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"[A] principle to be vital must be capable of wider application than the mischief which gave it birth." – Louis D. Brandeis

I. INTRODUCTION

Transmission, which has long played a supporting role to the generation and sale of electricity, has now captured center stage.[1] Congress has directed the Secretary of Energy to conduct a nation-wide study of electricity transmission congestion and designate any area experiencing congestion that adversely affects customers as a national interest electric transmission corridor.[2]

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1. *See, e.g.*, Jon Wellinghoff et al., Letter to the Editor, *FERC is Doing the Right Thing,* WALL ST. J., Jan. 10, 2011, at A16 ("[I]nvestment in transmission promotes efficient and competitive electricity markets, which hold down prices for consumers. Transmission investment also enhances reliability and allows access to new energy resources. . . . Our actions will assist regions that seek to modernize their electric infrastructure to better compete in the global economy."); Matthew L. Wald, *Wind Energy Bumps into Power Grid's Limits,* N.Y. TIMES, Aug. 27, 2008, at A1; s*ee also* Ill. Commerce Comm'n v. FERC, 576 F.3d 470, 478 (7th Cir. 2009) (Cudahy, J., dissenting) ("The United States is now engaged in an urgent project to upgrade its electric transmission grid, which for years has been generally regarded as inadequate.").

2. 16 U.S.C. § 824(p)(a) (2006); *see also* U.S. DEP'T OF ENERGY, NATIONAL INTEREST ELECTRIC TRANSMISSION CONGESTION STUDY (2006), *available at* http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-10.3.pdf. States generally site transmission facilities, but under certain limited circumstances, the FERC has backstop transmission siting authority in national interest electric transmission corridors. 16 U.S.C. § 824p (2006); *see also*

The Department of Energy has promised approximately $3.4 billion dollars of American Recovery and Reinvestment Act of 2009[3] funding to various smart grid[4] endeavors.[5] Just this past year, the Federal Energy Regulatory Commission ("Commission" or "FERC") launched two groundbreaking transmission-related rulemaking proceedings, one on transmission planning and cost allocation, including for transmission projects that traverse several states or regions,[6] and the other on integrating variable energy resources, such as wind and solar power, into the transmission grid.[7] Further, the Commission has avidly

Piedmont Envtl. Council v. FERC, 558 F.3d 304, 315 (4th Cir. 2009) (holding that FERC only has transmission siting authority when the state cannot act, fails to act in a timely manner, or acts inappropriately by granting a permit with unattainable conditions). In addition, Congress directed FERC to adopt rules providing the opportunity to collect incentive-based transmission rates, including a return on equity that attracts investment in transmission, such as the deployment of new transmission technologies. 16 U.S.C. § 824(s) (2006); *see also* Debbie Swanstrom & Meredith M. Jolivert, *DOE Transmission Corridor Designations and FERC Backstop Siting Authority*: *Has the Energy Policy Act of 2005 Succeeded in Stimulating the Development of New Transmission Facilities?*, 30 ENERGY L.J. 415, 459-60 (2009).

3. American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5, 123 Stat. 115 (2009).

4. The term "smart grid" refers to the marriage of information technology and the electric system. More precisely it means "combining time-based prices with the technologies that can be set by users to automatically control their use and self-production, lowering their power costs and offering other benefits such as increased reliability to the system as a whole." PETER FOX-PENNER, SMART POWER: CLIMATE CHANGE, THE SMART GRID, AND THE FUTURE OF ELECTRIC UTILITIES 10 (2010).

5. *See, e.g.*, *DOE to Award Smart Grid Funds Today,* ELEC. POWER DAILY, Oct. 27, 2009. Congress appropriated $4.5 billion for DOE to modernize the transmission grid; $3.5 billion for Smart Grid Investment Grant Program. Dep't of Energy, http://www.energy.gov/recovery/ smartgrid.htm (last visited Jan. 18, 2011).

6. *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 75 Fed. Reg. 37,884, 37,884 (proposed June 30, 2010) (to be codified at 18 C.F.R. pt. 35) (proposing to amend transmission planning and cost allocation requirements to ensure that Commission-jurisdictional services are provided in a just and reasonable and not unduly discriminatory or preferential manner).

7. Integrating Variable Energy Resources, 75 Fed. Reg. 75,335 (proposed Dec. 2, 2010) (to be codified at 10 C.F.R. pt. 430) (proposing to improve transmission scheduling practices to allow wind and solar developers to adjust their transmission scheduling on a more frequent basis; provide better

implemented financial incentives for new, non-routine transmission infrastructure, responding, in part, to Congressional directive.[8]

The need for transmission has intensified now that many states have adopted renewable portfolio standards.[9] This is partially attributable to the fact that many of these abundant renewable resources, such as those located in the Southwest and Northwest, are "location constrained," i.e., remotely located from customer centers, in regions where there is insufficient

communications between utilities and renewable generators; and establish a generic ancillary service rate schedule for generator regulation service).

8. Congress directed FERC to adopt rules providing the opportunity to collect incentive-based transmission rates, including a return on equity that attracts investment in transmission, such as the deployment of new transmission technologies. 16 U.S.C. § 824(s) (2006). FERC accomplished this mandate in Promoting Transmission Investment Through Pricing Reform, Order No. 679, 71 Fed. Reg. 43,294, 43,294 (Fed. Energy Reg. Comm'n July 31, 2006), *order on reh'g*, Order No. 679-A, 72 Fed. Reg. 1152 (Fed. Energy Reg. Comm'n Jan. 10, 2007), *order on reh'g*, 119 F.E.R.C. ¶ 61,062 (2007) (adopting regulations to bolster investment in transmission infrastructure, promote reliability, and reduce costs to consumers). The Commission has granted incentives in over fifty cases. The details of these cases can be found at FERC, *eLibrary*, http://www.ferc.gov/docs-filing/elibrary.asp (last visited Mar. 14, 2011); *see also* Posting of Esther Whieldon to Power Lines, http://www.platts.com/weblog/powerlines/2010/11/01/ferc_does_its_part_for_administrations.html (Nov. 1, 2010, 15:17 EST) (reporting that FERC awarded some incentives to a project that supported the public policy goal of getting more renewable on line despite the fact that it had not been proven to reduce congestion or ensure grid reliability).

9. A Renewable Portfolio Standard ("RPS") requires a percentage of an electricity provider's energy sales ("MW/h") or installed capacity ("MW") to be derived from renewable resources. *See* Joshua P. Fershee, *Moving Power Forward: Creating a Forward-Looking Energy Policy Based on a National RP*S, 42 CONN. L. REV. 1405, 1415 (2010) (asserting that successful RPS will require significant infrastructure investment, including transmission); *see also* Cal. Indep. Sys. Operator Corp., 133 F.E.R.C. ¶ 61,224, at P 2 (2010) (revising transmission planning process to create a new category of "policy-driven" transmission, which would include transmission required to assist utilities in meeting California's RPS goals). As of August 2010, 29 states and the District of Columbia have an RPS, 7 states and 3 power authorities (Nebraska's two larges public power districts and the Tennessee Valley Authority, which spans a 7-state region), have renewable goals. FERC, Market Oversight, Renewable Power & Energy Efficiency Market: Renewable Portfolio Standards, http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf (last visited Feb. 22, 2011) (map percentages are final year's targets).

transmission capacity to bring the resource to major markets.[10] Whereas transmission development was once exclusively the province of incumbent utilities, independent transmission developers and merchant transmission developers are increasingly getting into the act, eager to build transmission facilities to bring renewable energy to purchasers.

Merchant transmission providers are distinguished from other transmission providers by the fact that they do not serve captive retail customers and assume all market risk of a transmission project.[11] For the past decade, the Commission has recognized the important role merchant transmission projects can play in expanding competitive generation alternatives.[12] The

10. *See* Andrew Revkin, *California Utility Looks to Mojave Desert Project for Solar Power,* N.Y. TIMES, Feb. 12, 2009, at B3 ("The reality is that renewable projects are very far away from where customers are[.]"); s*ee also* Ill. Com. Comm'n*,* 576 F.3d at 478 (stating that electricity restructuring and "demand for power from renewable generation sources (such as wind farms) that are often located in places remote from centers of electric consumption" have placed additional strains on the already strained transmission grid.); SunZia Transmission, L.L.C. (*SunZia*), 131 F.E.R.C. ¶ 61,162, at P 21 (2010) ("The Commission is committed to supporting the development of new transmission infrastructure that is essential not only to providing location-constrained resources with access to markets, but also to meeting our nation's current and future energy needs.") (citing Tres Amigas, L.L.C. (*Tres Amigas I*), 130 F.E.R.C. ¶ 61,207 (2010); Cal. Indep. Trans. Sys. Operator Corp., 119 F.E.R.C. ¶ 61,061 (2007) (discussing unique challenges associated with location-constrained resources)).

11. Unlike traditional public utilities, merchant transmission providers assume all of a project's market risk and have no captive pool from which to recoup project costs. *See* Chinook Power Transmission, L.L.C. (*Chinook*), 126 F.E.R.C. ¶ 61,134, at P 1 n.1 (2009). Merchant transmission projects are distinct from independent transmission projects that request Commission approval for incentive rates, and whose costs are allocated to one or more customers without each customer's contractual consent. *See, e.g.,* Nev. Hydro Co., 122 F.E.R.C. ¶ 61,272 (2008) (annualized cost included in California Independent System Operator's rate base); Trans Bay Cable, L.L.C., 112 F.E.R.C. ¶ 61,095 (2005) (same).

12. *See* Wyo. Colo. Intertie, L.L.C., 127 F.E.R.C. ¶ 61,125, at P 38 (2009) (stating that merchant transmission projects "can play a useful role in expanding competitive generation alternatives for customers and meeting reliability needs"); *see also* TransÉnergie U.S. Ltd. (*TransÉnergie I*), 91 F.E.R.C. ¶ 61,230, 61,838 (2000) (agreeing with applicant that merchant transmission "enhances competition and market integration by expanding capacity and trading opportunities between the New England and New York markets."); *accord Tres Amigas I*, 130 F.E.R.C. ¶ 61,207, at P 77 (2010), *order on motion for*

Commission has granted merchant transmission developers the right to charge for transmission service at negotiated rates, unencumbered by the traditional cost of service ratemaking principles and filings usually applied to transmission service.[13] FERC's orders harmonize the Commission's statutory responsibility to ensure that rates, terms and conditions of service are just and reasonable and not unduly discriminatory[14] with the merchant transmission developer's need to obtain financing for its projects.[15] Unlike incumbent utilities, merchant transmission developers have no obligation to build transmission projects, and will only do so where they are financially viable. The challenge for the Commission, therefore, is to facilitate financing transmission construction where it is needed, while at the same satisfying the requirement under the Federal Power Act ("FPA") that rates are just and reasonable[16] and preserving core

clarification, 131 F.E.R.C. ¶ 61,281 (2010), *reh'g denied,* 132 F.E.R.C. ¶ 61,233 (2010).

13. *See, e.g.*, Champlain Hudson Power Express, Inc. (*Champlain*), 132 F.E.R.C. ¶ 61,006, at P 59 (2010) (waiving the cost-based data and Form No. 1 filing requirements); *Chinook*, 126 F.E.R.C. ¶ 61,134 at P 68-69 (same). Lacking captive customers, merchant transmission providers do not earn the regulated, cost-based rate of return that captive customers would traditionally pay. Instead, merchant transmission providers' compensation comes from contracts they sign with customers to transmit electricity over their merchant transmission lines. *See* MATTHEW H. BROWN & RICHARD P. SEDANO, ELECTRICITY TRANSMISSION: A PRIMER 73 (2004), *available at* http://envhist.wisc.edu/cool_stuff/energy/grid.shtml. An advantage of this approach is that it enables multi-state projects to progress outside the complicated process of inter-regional cost allocation; *see* Tres Amigas (*Tres Amigas III*), 132 F.E.R.C. ¶ 61,233, at P 29 (2010).

14. Section 205 of the Federal Power Act ("FPA") requires that "[a]ll rates and charges made . . . shall be just and reasonable." 16 U.S.C. § 824d(a) (2006). "FERC's actions must be solidly grounded in its authorizing statutes." Hon. Jon Wellinghoff & David Morenoff, *Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation,* 28 ENERGY L.J. 389, 397 (2002).

15. *Chinook*, 126 F.E.R.C. ¶ 61,134 at P 45.

16. 16 U.S.C. § 824d(a) (2006). Courts have upheld FERC's interpretation of the FPA as not requiring the use of any particular ratemaking methodology so long as the rates fall within a zone of reasonableness (i.e. neither excessive to the consumer nor less than compensatory to the seller). *See, e.g.*, Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944); Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679, 692-93 (1923). In 1991, the Supreme Court affirmed that "the just and reasonable standard does not compel the Commission to use any single pricing formula. . . ." Mobil

principles like open access to transmission service and[17] transparency in capacity allocation.[18]

This article examines the Commission's justification for granting merchant transmission providers negotiated rates in the context of antecedents in market-based rates for electricity generation and natural gas regulation. Evolution of the Commission's analysis for authorizing negotiated rates for merchant transmission analysis is considered, along with an assessment of the issues the Commission is likely to continue grappling with in the future. Specifically, this article begins with an overview of the Commission's market-based rate program because it was a precursor to negotiated rates for merchant transmission and provides a framework for evaluating similar market power[19] concerns. It then turns to a consideration of natural gas regulation, to examine critical concepts merchant transmission developers borrowed from this discipline, notably negotiated rates, open seasons, and the use of anchor shippers or

Oil Exploration & Producing Se. Inc. v. United Distrib. Cos., 498 U.S. 211, 224 (1991) (discussing the "just and reasonable" standard in the natural gas context). It is a well-settled principle that comparable provisions, Natural Gas Act sections 4 and 5 and Federal Power Act sections 205 and 206, are generally read in pari materiae. Ky. Utils. Co. v. FERC, 760 F.2d 1321, 1321 n.6 (D.C. Cir. 1985).

17. "Open access" refers to non-discriminatory access to the transmission grid. In 1993, the Commission began to require individual utilities, on a case-by-case basis, to transmit competing wholesale sellers' electricity over the utility's transmission lines. In 1996, to foster greater competition in wholesale power markets, the Commission promulgated industry-wide rules mandating all public utilities offer open access transmission service. *See* Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890-D, 129 F.E.R.C. ¶ 61,126, at P 1 (2009) (citing Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Transmitting Utilities, Order No. 888 (*Order No. 888*), 61 Fed. Reg. 21,540 (May 10, 1996), 82 F.E.R.C. ¶ 61,046 (1998)); *see also* New York v. FERC, 535 U.S. 1, 1 (2002); Transmission Access Policy Study Grp. v. FERC, 225 F.3d 667, 667 (D.C. Cir. 2000).

18. *See, e.g.,* Mont. Alta. Tie, Ltd. (*MATL*), 116 F.E.R.C. ¶ 61,071, at P 37 (2006) ("[T]he Commission's concern in evaluating the open season process is to provide transparency in the bidding process and to enable unsuccessful bidders to determine if they were treated in a fair manner.").

19. The Commission has defined market power as a seller's ability to "significantly influence price in the market by withholding service and excluding competitors for a significant period of time." Citizens Power & Light Corp., 48 F.E.R.C. ¶ 61,210, 61,777 (1989).

anchor customers to secure financing for a project. A comparison is made between market-based rates for natural gas storage and negotiated rates for transmission with respect to market power concerns. Next, this article examines how the Commission's evaluation of merchant transmission applications developed over time into the current, flexible four-factor approach. The article concludes with a summary of the key requirements the Commission currently emphasizes when granting negotiated rates for merchant transmission and highlights a few potential issues for future consideration.[20]

II. MARKET-BASED AND NEGOTIATED RATE POLICIES

A. Market-Based Rates for Electricity

For most of the history of regulation under the FPA, rates for service were established under traditional cost of service ratemaking principles, pursuant to which a utility's cost of providing service is ascertained and rates are assessed on that basis.[21] Moreover, nearly all service provided by public utilities was offered on a "bundled basis" – combined generation, transmission, and distribution service – to retail customers taking retail service regulated by state public service commissions. FERC and its predecessor, the Federal Power Commission, have authority under the FPA to regulate interstate transmission and wholesale sales of electricity, but little such service was historically provided on an unbundled basis.[22]

20. On the brink of this article's publication, the Commission signaled its interest in further exploring merchant transmission issues in a technical conference forum. *See* Notice of Technical Conference re Priority Rights to New Participant Funded Transmission, 76 Fed. Reg. 11,238, 11,238 (Mar. 1, 2011) (exploring issues related to new transmission infrastructure ownership models, including merchant transmission).

21. For a complete discussion of traditional cost of service ratemaking, see generally JAMES C. BONBRIGHT ET AL., PRINCIPLES OF PUBLIC UTILITY RATES (1961).

22. *See generally* New York v. FERC, 535 U.S. 1 (2002).

With the passage of Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"),[23] Congress encouraged the development of independently owned power generation through a program entitling independent power producers ("IPPs") to sell their power to utilities at a utility's own incremental cost of providing electricity ("avoided cost").[24] With that, and with FERC's authority to compel the provision of unbundled transmission service under section 211 of the FPA,[25] attention turned to the conditions under which independent generators could gain access to the unbundled transmission service essential to serving a newly competitive wholesale market. Further, the increasing availability of competitive generation raised the question whether such generation was sufficiently competitive to protect customers and ensure just and reasonable rates through competition instead of via traditional cost of service regulation.[26]

While Section 211 of the FPA authorized FERC to compel the provision of transmission service on a case-by-case basis, the Commission concluded in issuing Order No. 888 that a ubiquitous "open access" requirement was necessary to protect customers, including IPPs, from discrimination in the provision of transmission service deemed essential to achieving sufficiently robust generation competition.[27] The Commission concluded that without regulatory reform, utilities possessed an economic incentive to block competitors' access to their transmission networks, protecting their monopoly status within a geographic region or service territory.[28]

With the provision of open access transmission service in place, in conjunction with technological advances that improved the competitiveness of wholesale power markets, the Commission

23. 16 U.S.C. § 824a-3.

24. 16 U.S.C. § 824a-3(d).

25. *See* 18 U.S.C. § 824j.

26. New York v. FERC, 535 U.S. at 26.

27. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and transmitting Utilities, FERC Order No. 888-A, 62 Fed. Reg. 12,274, 12,275 (Mar. 14, 1997) ("[A]bsent open access, undue discrimination will continue . . . .").

28. Atl. City Elec. Co. v. FERC, 295 F.3d 1, 4 (D.C. Cir. 2002).

began considering applications for market-based rates for wholesale power sales.[29] In contrast to a cost-based rate, a market-based rate does not specify the precise rate, but rather allows the rate to be negotiated or arbitrated between the seller and its customers. Granting market-based rate authority in lieu of setting cost-based rates for wholesale power sales constituted a fundamental shift in Commission policy. Whereas cost-based ratemaking "focused on preventing the exercise of market power by controlling profits rather than fostering efficiency[,]"[30] market-based rates were intended to "create competitive pressures that would improve efficiency, reduce costs, and lower wholesale power prices."[31]

Turning to the law, the Commission found in the statutory mandate to set "just and reasonable" rates under section 205 of the FPA,[32] the provision under which it has historically approved cost-based rates, sufficient authority to allow market forces to protect the public interest.[33] The Commission found, and courts agreed, that in a competitive market, market-based rates are just and reasonable, provided "the seller and its affiliates do not have, or adequately have mitigated, market power."[34] The principle underlying this approach is that "in a competitive market, where neither buyer nor seller has significant market power, it is

29. *See* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697 (*Order No. 697*)**,** 121 F.E.R.C. ¶ 61,260, at P 7 (2007).

30. Hon. Joseph T. Kelliher, *Market Manipulation, Market Power, and the Authority of the Federal Energy Regulatory Comm'n,* 26 ENERGY L.J. 1, 9 (2005) (citing ALFRED E. KAHN, THE ECONOMICS OF REGULATION, PRINCIPLES AND INSTITUTIONS 26-30 (1970)).

31. Hon. Joseph T. Kelliher & Maria Farinella, *The Changing Landscape of Federal Energy Law,* 61 ADMIN. L. REV. 611, 643 (2009); *see also* Entergy Servs. Inc., 58 F.E.R.C. ¶ 61,234, 61,753 (1992) (approving market-based rates because rates set through competitive forces will result in cost savings to ratepayers); Public Serv. Co. of In., 51 F.E.R.C. ¶ 61,367, 61,224-25 (1990) (finding that competitive pricing improves efficiency by creating incentives for full use of existing capacity).

32. 16 U.S.C. § 824d(a).

33. Kelliher & Farinella, *supra* note 31, at 643-44.

34. La. Energy & Power Auth. v. FERC, 141 F.3d 364, 365 (D.C. Cir. 1998) (rejecting challenge to FERC's approval of an electrical utility's application to charge market-based rates because FERC had determined the utility lacks market power).

rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment."[35] While the Supreme Court has yet to opine on the lawfulness of the market-based rate program, "[b]oth the Ninth Circuit and the D.C. Circuit have generally approved FERC's scheme of market-based rates."[36]

From the inception of the market-based rate program, the Commission has evaluated wholesale supplier applications for market-based rates on a case-by-case, applicant-centric basis.[37] The Commission does not evaluate the competitiveness of the market as a whole, but rather whether the market is competitive vis-à-vis the applicant for market-based rate authority, and courts have endorsed this approach.[38]

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35. Lockyer v. FERC, 383 F.3d 1006, 1013 (9th Cir. 2004) (quoting Tejas Power Corp. v. FERC, 908 F.2d 998, 1004 (D.C. Cir. 1990)).

36. Morgan Stanley v. Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash., 554 U.S. 527, 538 (citing *Lockyer*, 383 F.3d at 1011-13; *La. Energy & Power Auth.*, 141 F.3d at 365). The D.C. Circuit first upheld market-based rates in the natural gas context, holding that "when there is a competitive market the FERC may rely upon market-based prices in lieu of cost-of-service regulation to assure a 'just and reasonable' result." Elizabethtown Gas Co. v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993). The court in *Louisiana Energy & Power Authority* first upheld market-based rates for an electric utility. The case involved a plaintiff's challenge to FERC's approval of an electric utility's application to charge. *La. Energy & Power Auth.*, 141 F.3d at 365.

37. *See Order No. 697*, 121 FERC ¶ 61,260, at P 7 (2007).

38.

> We have never held that FERC must establish the competitiveness of an entire market before permitting any participant to charge market-based rates. We have required that, before FERC approves an individual seller's use of market-based pricing in lieu of cost-of-service regulation, it must determine that "the seller and its affiliates do not have, or adequately have mitigated, market power in the generation and transmission of [electric] energy, and cannot erect other barriers to entry by potential competitors. . . . In other words, *what matters is whether an individual seller is able to exercise anticompetitive market power, not whether the market as a whole is structurally competitive.*

Blumenthal v. FERC, 552 F.3d 875, 882 (D.C. Cir. 2009) (citing *La. Energy & Power Auth.*, 141 F.3d at 365) (emphasis added); *see also* Consumers Energy Co. v. FERC, 367 F.3d 915, 922-23 (D.C. Cir. 2004); *Elizabethtown Gas Co.*, 10 F.3d at 871; *see also Tejas Power Corp.*, 908 F.2d at 1004.

Over time, the Commission steadily refined its market power tests to better protect customers from the exercise of market power and to provide greater certainty to sellers seeking market-based rate authority. The Commission's efforts culminated in a final rule issued on June 21, 2007, which reformed its market-based rate program and codified its market-based rate standards in its regulations.[39] There are three critical features of the Commission's current market-based rate regime: upfront applicant evaluation; additional safeguards against market power exercise in organized markets; and multiple layers of ongoing evaluation to protect consumers.[40]

The first of these features, "rigorous" upfront analysis, calls for an assessment of whether the applicant-seller has or any of its affiliates have market power in generation or transmission and, if so, whether such market power has been mitigated.[41] The Commission uses a two-part test. Part one assesses horizontal (generation) market power using two indicative screens: (1) pivotal supplier analysis, based on annual peak demand and (2) seasonal market share analysis.[42] Failure of either screen creates the rebuttable presumption that the applicant seller has market power.[43] The second part of the test evaluates vertical (transmission and other barriers to market entry) market power. To prevent the exercise of vertical market power, the Commission requires that where a public utility or its affiliate owns, operates or controls transmission facilities, it must have an Open Access Transmission Tariff on file with the Commission before obtaining authorization to charge market-based rates.[44] In addition, if a transmission owner loses market-based rate authority, there is a rebuttable presumption that all of its affiliates in the same market will also lose market-based rate authority.[45]

If the seller is authorized to charge market-based rates, the authorization is conditioned on: (1) affiliate restrictions on

39. *Order No. 697*, 121 F.E.R.C. ¶ 61,260, at P 6 (2007).
40. *Id.* at P 2.
41. *Id.*
42. *Id.* at P 13-20.
43. *Id.* at P 13.
44. *Id.* at P 21.
45. *Order No. 697*, 121 F.E.R.C. ¶ 61,260 at P 2.

transactions and conduct between power sales affiliates where one or more affiliates have captive customers and (2) ongoing filing requirements.[46] Order No. 697 codifies the prohibition on power sales between a franchised public utility with captive customers and its affiliates without first receiving Commission authorization.[47] It also codifies the restriction contained in the market-based rate code of conduct regarding separation of functions, information sharing, sales of non-power goods, and power marketing.[48] As for ongoing filing requirements, these include the submission of post-transaction electric quarterly reports containing specific information about contracts and transactions; the notification of any change of status; and the updates large sellers must file triennially.[49]

The second feature of the market-based rate regime requires wholesale sellers that have market-based rate authority and sell into the markets administered by a Regional Transmission Organization ("RTO") or Independent System Operator ("ISO") to abide by the market rules the Commission has approved for all market participants.[50] These market rules provide additional checks on market power to ensure rates are just and reasonable. They include market power mitigation measures, price caps where appropriate, and market monitors to help oversee market behaviors and competitive conditions.

46. *Id.*; *see also* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697-A, 123 F.E.R.C. ¶ 61,055, at P 410 (2008) (explaining that "the Commission has in place "multiple layers" of protections for customer to ensure that market based rates are just and reasonable and that they remain so.").

47. *Order No. 697*, 121 F.E.R.C. ¶ 61,260 at P 23.

48. *Id.*

49. *Id.* at P 3. "Mitigation" of market power is required for sellers who fail one or both of the indicative horizontal market power screens and, if they attempted to rebut the presumption of market power with a delivered price test, failed that test. The Commission's default is cost-based mitigation, although sellers can propose alternative non-cost based mitigation, which the Commission may approve on a case-by-case basis. *Id.* at P 25 n.12. This may include the spin-off of generation that enables the seller to exercise market power. Mitigation applies in all balancing area authorities where the seller is presumed or found to have market power; mitigated sellers can obtain and retain market-based rate authority in areas where the Commission has found they do not have market power. *Id.* at P 28.

50. *Id.* at P 4.

Third, after the initial authorization has been granted, the Commission exercises ongoing oversight of market conditions and market-based rate authorizations. The Commission addresses any market power concerns that subsequently develop and modifies rates as necessary. This oversight is accomplished in part through its "significantly enhanced" market oversight and enforcement division, as well as the opportunity to act on complaints (initiated *sua sponte* or by a market participant) under section 206 of the FPA.[51] For example, if an electric quarterly report or a triennial update filing indicates that a seller may have acquired market power subsequent to receipt of its original market-based rate authorization, the Commission may initiate a section 206 proceeding to revoke a seller's market-based authorization. Based on review of electronic quarterly reports or daily price information, the Commission may also investigate a specific public utility or market anomaly to ascertain whether there has been any violation of RTO/ISO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take remedial action. Remedies include refunds to customers, disgorgement of profits for tariff violations, and civil penalties if the seller engaged in prohibited market manipulation or violated Commission orders, tariffs, or rules. In addition, the Commission could refer the matter to the Department of Justice for potential criminal prosecution.[52]

In the twenty years since the Commission first began to grant market-based rate authority, the Commission has evinced a willingness to refine its market-based rate program continuously and to guard vigilantly against the exercise of market power. The current market-based rate program entails "multiple layers"[53] of filing and reporting requirements and incorporates numerous[54] protections against excessive rates. The ongoing reporting requirement was a critical factor in persuading the United States Court of Appeals for the Ninth Circuit to uphold generally the

51. 16 U.S.C. § 824(e) (2006).
52. 16 U.S.C. § 825m (2006).
53. *Order No. 697*, 121 F.E.R.C. ¶ 61,260 at P 967.
54. *Id.* at P 970.

Commission's market-based rate program.[55] Further, preventing affiliate abuse is a critical component of the Commission's market-based rate program. Finally, the market-based rate applicant has the burden to justify that it lacks market power or has adequately mitigated power, and this is a continuing obligation. While its authorization of negotiated rates for merchant transmission only reaches back a decade, to a certain degree, the Commission implicitly incorporates these aspects of its market-based rate program into its merchant transmission assessment in order to protect customers.

B. Natural Gas Act Precedent:

1. Negotiated/Recourse Rates

The Commission's traditional approach to natural gas ratemaking has been to set an annual revenue requirement for regulated interstate pipelines based on operating and capital costs incurred during a historic test period, adjusted for known and measurable changes expected to occur by the time rates take effect.[56] In general, rates are designed to recover the annual revenue requirement based on contract capacity entitlements and projected annual or seasonal volumes.[57] In 1989, Congress urged the Commission to "improve the competitive structure [of the natural gas industry] in order to maximize the benefits of wellhead decontrol."[58] The Commission responded by taking steps to ensure that all natural gas customers (i.e. shippers) have meaningful access to the transportation system and to maximize competition through an open access program that served as the intellectual antecedent to Order No. 888 in the electric

55. Lockyer v. FERC, 383 F.3d 1006, 1015-16 (9th Cir. 2004) (finding of the absence of market power, coupled with ongoing reporting requirements, satisfies the notice and filing requirements of section 205 of the Federal Power Act).

56. Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 70 F.E.R.C. ¶ 61,139, 61,393 (1995).

57. *Id.*

58. H.R. REP. NO. 29, at 6 (1980) (cited in Alternatives to Traditional Cost-of-Service Ratemaking of Natural Gas Pipelines, 74 F.E.R.C. ¶ 61,076, 61,225 n.2 (1996). Wellhead decontrol refers to the cessation of regulation of natural gas prices.

industry.[59] The next step was to provide additional rate design flexibility in the post-restructuring environment.[60] In its 1996 Alternative Rate Policy Statement, the Commission declared that it was willing to accept, on a shipper-by-shipper basis, filings requesting authority to charge negotiated rates for pipeline transportation service.[61] But the Commission made clear that it would only accept such negotiated rates subject to the proviso that customers retain the ability to choose a cost-of-service based tariff rate as backstop regulatory protection from the exercise of market power.[62] The Commission concluded that negotiated/recourse service – rates negotiated between the pipeline and the customer, with a recourse cost-of service rate available at the customer's request – could achieve flexible, efficient pricing when market-based rates would not be appropriate due to concerns the pipeline could potentially

59. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas After Partial Wellhead Decontrol, Order No. 636, 57 Fed. Reg. 13267, 13295 (1992), FERC Stats. & Regs ¶ 30,939, *order on reh'g,* Order No. 636-A, FERC Stats. & Regs. ¶ 30,950, *order on reh'g,* Order No. 636-B, 61 F.E.R.C. ¶ 61,272 (1992), *reh'g denied*, Order No. 636-C, 62 F.E.R.C. ¶ 61,007 (1993), *aff'd in part and remanded in part sub nom*; United Distrib. Cos. v. FERC*,* 88 F.3d 1105 (D.C. Cir. 1996), *order on remand*, Order No. 636-C, 78 F.E.R.C. ¶ 61,186 (1997).

60. *See* Alternatives to Traditional Cost-of-Service Ratemaking of Natural Gas Pipelines, 74 F.E.R.C. ¶ 61,076, 61,225 (1996), *reh'g and clarification denied*, 75 F.E.R.C. ¶ 61,024 (1996), *petitions denied and dismissed*, Burlington Res. Oil & Gas Co. v. FERC, 172 F.3d 918 (D.C. Cir. 1998) [hereinafter 1996 Alternative Rate Policy Statement]; *see also* Natural Gas Pipeline Co. of Am., 72 F.E.R.C. ¶ 61,083, 61,440 (1995) (willing to permit pipelines flexibility to negotiate rates with current and prospective customers for unsubscribed capacity). The initial rate placed into effect via a certificate proceeding under section 7 of the Natural Gas Act, 15 U.S.C. § 717f (2006), establishes the maximum recourse rate ceiling level, unless the natural gas pipeline makes a filing to change the recourse rate under section 4 of the Natural Gas Act, 15 U.S.C. § 717c(2006). *See* Portland Natural Gas Trans. Sys., 134 F.E.R.C. ¶ 61,129, at P 3-7 (2011).

61. 1996 Alternative Rate Policy Statement, *supra* note 60, at 61,241. With respect to market-based rates, the Commission pointed out that it had already determined that "where a natural gas company can establish that it lacks significant market power, market based rates are a viable option for achieving the flexibility and added efficiency required by the current market-place." *Id*. at 61,227 (citations omitted).

62. *Id.*

exercise market power.[63] The availability of a recourse service would prevent pipelines from exercising market power because the customer could always fall back on the traditional cost-of-service rate if the pipeline were to withhold service or demand excessive rates.[64] In this manner, the recourse rate mitigates market power, and thus obviates the need to demonstrate absence of market power.[65] "At a minimum, negotiated/recourse rates offer the potential for increased market responsiveness in pipeline services without protracted disputes regarding market power."[66] While the Commission has updated its natural gas pricing policy a few times since it was first issued,[67] this remains the basic framework.

2. Natural Gas Storage Service

The Commission generally evaluates applicants' requests for market-based rates for storage services under its 1996 Alternative Rate Policy Statement.[68] The Commission has approved market-based rates for storage providers where the applicant has demonstrated it lacks market power or has adopted conditions that significantly mitigate market power.[69] For example, the Commission has approved applications for market-based rates for storage where it found the applicants would be unable to exercise market power due to their small size, the presence of numerous competitors, or the small share of the market that the participant has.[70] In defining the relevant market for purposes of calculating market concentration and

63. *Id.* at 61,240.

64. *Id.*

65. *Id.*

66. *Id.*

67. *See, e.g.*, Certification of New Interstate Natural Gas Pipeline Facilities (*1999 Pricing Policy Statement*), 88 F.E.R.C. ¶ 61,227, 61,737 (1999) (establishing rebuttable presumption favoring incremental rates over rolled-in rates to protect historic customers from subsidizing new customers), *clarified*, 90 F.E.R.C. ¶ 61,128, *further clarified*, 92 F.E.R.C. ¶ 61,094 (2000).

68. *See generally* 1996 Alternative Rate Policy Statement, *supra* note 60.

69. Rate Regulation of Certain Natural Gas Storage Facilities, Order No. 678 (*Order No. 678*), 71 Fed. Reg. 36,612, 36,612 (June 27, 2006) (to be codified at 18 C.F.R. pt. 284).

70. *See, e.g.,* Egan Hub Partners, 99 F.E.R.C. ¶ 61,269, at P 17 (2002).

market share, pursuant to Order No. 678, the Commission now allows consideration of close substitutes for gas storage, such as available pipeline capacity, liquefied natural gas, local gas production, and released transportation capacity.[71] To be a good substitute, the alternative must be comparable in terms of availability, quality, and price.[72]

Section 312 of the Energy Policy Act of 2005[73] ("EPAct 2005") added a new section 4(f) to the Natural Gas Act ("NGA").[74] This provision explicitly gives the Commission authority to permit natural gas companies to provide storage and storage-related services at market-based rates for new storage capacity (placed into service after the date of enactment of the Act), even where the company cannot demonstrate it lacks market power. To authorize negotiation of market-based rates for natural gas storage where the applicant cannot demonstrate lack of market power, the Commission must determine that market-based rates are in the public interest and needed to encourage the construction of the capacity.[75] It also must ensure that reasonable terms and conditions are in place to protect consumers and periodically review the market-based rates authorized to ensure they remain just, reasonable, and not unduly discriminatory or preferential.[76]

In addition to modifying the Commission's market power analysis to allow consideration of close substitutes for natural gas, as discussed above, Order No. 678 also adopted regulation implementing section 4(f) of the NGA.[77] Order No. 678 permits

71. *Order No. 678*, 71 Fed. Reg. at 36,612; *see also* Steckman Ridge, L.P., 123 F.E.R.C. ¶ 61,248, at P 33 (2008) (approving market-based rates for storage where proposed storage facilities will be in a highly competitive area with numerous storage alternatives; proposed market shares are low, market area HHI of the applicant and its affiliates are mitigated by applicant's small market share, the availability of competing services, affiliate storage fields are subject to cost-based rates and applicants entry into the market will increase storage options in the region).

72. *Order No. 678*, 71 Fed. Reg. at 36,617-18.

73. Energy Policy Act of 2005, Pub. L. No. 109-58, § 312, 199 Stat. 594, 688 (2005) (to be codified at 15 U.S.C. § 717 (c)(f)(1)(A)).

74. 15 U.S.C. § 717(c) (2006).

75. Energy Policy Act of 2005 § 312.

76. *Id.*

77. *See Order No. 678*, 71 Fed. Reg. at 36,612.

storage providers that are unable to demonstrate lack of market power to negotiate market-based rates if they meet the following criteria: (1) the capacity that enables provision of the service was placed in service after the enactment date of EPAct; and (2) market-based rates must be in the public interest and necessary to facilitate construction of storage capacity where the facility is needed; customers must be protected.[78] Further, the applicant can demonstrate storage is needed in the area by providing evidence of a lack of storage in the region; full utilization of existing storage capacity; nearby pipeline constraints; and projected increased demand for natural gas in the region.[79]

The Commission has declared that its pricing policies are to ensure access to storage services on a nondiscriminatory basis at just and reasonable rates and to provide that sufficient storage capacity will be available to meet anticipated increases in market demand.[80] The Commission further explained that Order No. 678's overarching purpose is to reduce the volatility of natural gas prices and improve adequacy of natural gas supply during peak demand periods by encouraging expansions of gas storage capacity while protecting customers from the exercise of market power. In essence, Order No. 678 reconciles, on the one hand, the need to facilitate development of new natural gas storage capacity, with, on the other hand, the statutory duty to protect customers from unjust and unreasonable rates.[81]

3. Precedent/Anchor Shipper Agreements

Prior to constructing any facilities for providing service or initiating any new service, the pipeline must receive permission from the Commission in the form of a certificate of convenience

78. *Id.* at 36,624.

79. *See, e.g.*, Tex. Gas Trans., L.L.C., 122 F.E.R.C. ¶ 61,190, 62,105 at P 25 (2008) (approving market-based rates where applicant demonstrated that but for the market-based rates the project would not be built; customers would be protected because the open season offered an incremental cost-based reserve price for the proposed storage capacity and all available market-based storage capacity will be posted on a website and available via proposed auctions).

80. *Id.* at P 32.

81. *Id.*

and necessity.[82] The Commission may impose conditions on the provision of service or construction of facilities.[83] Under the Commission's policy, the threshold requirement for proposing new projects is that the pipeline must be prepared to support the project without relying on subsidization from existing customers.[84] Furthermore, the Commission's policy requires that:

> "[A]ll new interstate pipeline construction must be preceded by a non-discriminatory, non-preferential, open-season process through which potential shippers may seek and obtain firm capacity rights. Second, as part of the open season, the project sponsor must offer a maximum recourse rate so that the bidder in the open season may have the option to choose between the recourse rate and a negotiated rate."[85]

In order to demonstrate interest and obtain a certificate (and financing), pipelines traditionally enter into precedent agreements, also called anchor shipper agreements.[86]

4. Prelude

In sum, as will become evident in the next section of this discussion, natural gas precedent provided an important template for merchant transmission proposals. Merchant transmission

82. *See* 15 U.S.C. § 717(f)(c) (2006).

83. JAMES H. MCGREW, FEDERAL ENERGY REGULATORY COMMISSION § 31.15 (2003).

84. Rockies Express Pipeline L.L.C., 116 F.E.R.C. ¶ 61,272, at P 36 (2006); *see generally* Certification of New Interstate Nat. Gas Pipeline Facilities (*1999 Policy Statement*), 88 F.E.R.C. ¶ 61,277 (1999), *order clarifying statement of policy,* 90 F.E.R.C. ¶ 61,128 (2000), *order further clarifying statement of policy,* 92 F.E.R.C. ¶ 61,094 (2000).

85. Rockies Express Pipeline L.L.C., 116 F.E.R.C. ¶ 61,272 at P 71.

86. *See, e.g.*, *id.* at P 24 (finding applicant's proposal to be in the public interest, where negotiated rate and contractual terms are dependent on whether the shipper qualifies as a Standard Shipper, Anchor Shipper or Foundation Shipper, and all potential shippers had notice of the different negotiated reservation rate options and had equal opportunity to bid for capacity of the project); Gulf Crossing Pipeline Co., L.L.C., 123 F.E.R.C. ¶ 61,100, at P 37 (2008) (conditioning certificate authorization so construction cannot begin until pipeline executed contracts reflecting the levels and terms of service represented in its precedent agreements).

developers borrowed the concept of negotiated rates. Although there is no explicit, Commission-approved maximum recourse rate in the merchant transmission context, there are implicit cost caps. As in the NGA certificate process, the Commission also requires the use of transparent open seasons and post-open season reporting to ensure there is no undue discrimination, and customers have equal opportunity to obtain access to the merchant transmission service. Within the past few years, as financing transmission projects grew more difficult, merchant transmission developers also borrowed the anchor shipper concept to line up anchor customer in advance to demonstrate and generate interest in the project and secure upfront financing. Finally, the negative implication that flows from section 4(f) of the NGA is that the Commission cannot assume a lack of market power for merchant transmission providers; rather, the Commission can only grant negotiated rate authority where there is an absence of market power, even if it would be in the public interest to build a line.[87]

III. NEGOTIATED RATES FOR MERCHANT TRANSMISSION AND PRIORITY ACCESS

A. Early Precedent: Open Season, Open Access and Ten Criteria

The early merchant transmission proposals were prompted in part by the development of organized markets – RTOs and ISOs. Particularly as these organized energy markets expanded in geographic scope, they created a concomitant need for additional transmission to support generation competition, and also provided opportunities for merchant transmission providers to

87. *Cf.* Estate of Bell v. Comm'r, 928 F.2d 901, 904 (9th Cir. 1991) ("Congress is presumed to act intentionally and purposely when it includes language in one section but omits it in another."); Ariz. Elec. Power Co-op. v. United States, 816 F.2d 1366, 1375 (9th Cir. 1987) ("When Congress includes a specific term in one section of a statute but omits it in another section of the same Act, it should not be implied where it is excluded.").

offer competitive generation alternatives.[88] Consequently, one feature these early cases had in common is that they involved applications for merchant transmission facilities located either within or adjacent to an organized market.[89] In these seminal cases, the Commission accepted the merchant transmission developers' basic economic rationale for justifying negotiated rates – i.e., that the negotiated rates will reflect the price differentials between location marginal prices in the organized markets at each end of the line, and will essentially be capped at the cost of expanding the systems at each end of the line.[90] The merchant transmission facilities essentially function as a generation substitute, providing a means to transmit lower cost generation from where the line begins (source) to a region of higher cost generation where the line ends (sinks).[91] In this

88. *See TransÉnergie I*, 91 F.E.R.C. ¶ 61,230, 61,838 (2000) (finding merchant transmission project connecting two organized markets "can play a useful role in expanding competitive generation alternatives for customers."); Neptune Reg'l Transmission Sys. (*Neptune I*), 96 F.E.R.C. ¶ 61,147, 61,633 *reh'g*, 96 F.E.R.C. ¶ 61,326 (2001), *on motion for clarification*, 98 F.E.R.C. ¶ 61,140 (2002), *granting in part and denying in part request for modification of prior order and granting clarification,* 103 F.E.R.C. ¶ 61,213 (2003) ("Like the TransÉnergie Project, the Commission believes that the Neptune Project can play a useful role in expanding competitive generation alternatives for customers."); *see also* Richard P. Bonnefield & Ronald L. Drewnoski, *Transmission at a Crossroads*, 21 ENERGY L.J. 447, 460 n.43 (2000) ("Merchant transmission lines can be installed between a source and a load market . . . . earning revenues by bidding into destination generation markets with generation purchased from the source market, thus earning arbitrage between the markets.").

89. *See Chinook*, 126 F.E.R.C. ¶ 61,143, at P 35 (2009).

90. *TransÉnergie I*, 91 F.E.R.C. at 61,836; *Neptune I*, 96 F.E.R.C. at 61,633; *Chinook*, 126 F.E.R.C. ¶ 61,134 at P 38 n.26. In *Chinook,* the Commission summarized:

> For example, negotiated rates may be appropriate when the service on a neighboring public utility under cost-of-service rates – essentially capped at the utility's cost of expansion – can provide a reasonable alternative. A further check on the negotiated rates could exist where the price customers are willing to pay for transmission service is disciplined by the difference in generation prices at the ends of the line (i.e., the market price of generation on either sides of the line).

Chinook, 126 F.E.R.C. ¶ 61,134 at P 38 n.26.

91. As economists have explained, "Merchant transmission projects that increase capacity between an import constrained area with high nodal prices and an export constrained area with low nodal prices are, in a sense, substitutes

manner, merchant transmission enhances competition and trading opportunities, and should help prices between the two regions to converge. The rationale behind negotiated rates for merchant transmission essentially parallels the justification for negotiated rates in the natural gas context. Natural gas pipelines are allowed to charge negotiated rates for transporting natural gas because the customer always has the option of requesting the pipeline to provide service under its cost-based recourse rate, which essentially caps the rate for transporting natural gas.[92] Where negotiated rate authority for merchant transmission is concerned, at least theoretically, the generator customer always has the option of requesting transmission service, and expansion if necessary to provide service, at cost-based rates from its incumbent utility provider.[93] The only ostensible difference between these two regimes is that in the merchant transmission context, the cost-based provider and the merchant transmission provider would be different entities, as opposed to a single natural gas pipeline.[94]

During this nascent period of assessing negotiated rate applications, the Commission also experimented with various criteria for evaluating the justness and reasonableness of negotiated rates for merchant transmission facilities. In particular, the Commission grappled with issues such as the use of open seasons to provide transparency and ensure there is no undue discrimination in the allocation of transmission rights on the merchant facilities; requiring transmission facilities to be turned over to a neighboring RTO/ISO and service provided

for generation projects of equivalent capacity inside the import constrained area." Paul Joskow & Jean Tirole, *Merchant Transmission Investment* 56 (Nat'l Bureau of Econ. Research, Working Paper No. 9534, 2003), *available at* http://econ-www.mit.edu/files/1159. "While the merchant transmission project does not compete directly with this kind of generation project, it does make it possible for generators outside the constrained area to compete with existing and new generators inside the import constrained area." *Id.*

92. 1996 Alternative Rate Policy Statement, *supra* note 60, at 61,241.

93. *See, e.g.*, *TransÉnergie I*, 91 F.E.R.C. at 61,838.

94. *See, e.g.*, *MATL*, 116 F.E.R.C. ¶ 61,071, at P 52 (2006) ("In summary, the Commission found in *TransÉnergie* that negotiated rate authority could be granted to a merchant transmission facility interconnected with an RTO given the cap effectively created by the difference in LMP prices on each end of the merchant line and the expansion cost cap.").

under the open access transmission tariff of the RTO/ISO that operates the merchant transmission facility; and prevention of favoritism towards affiliates. Key features of these critical cases are discussed below.

1. ***TransÉnergie*: Justification for Negotiated Rates and Evaluation Criteria**

In June 2000, the Commission granted the first merchant transmission owner application for negotiated rate authority in *TransÉnergie*.[95] TransÉnergie proposed to construct a 26-mile, undersea bi-directional high-voltage direct current[96] cable interconnection between Connecticut and Long Island, New York ("Cross-Sound Cable").[97] The Cross-Sound Cable would connect the control areas of the New York Independent System Operator ("NYISO") and the New England Independent System Operator ("ISO-New England").[98] TransÉnergie requested "blanket authority" to make sales of firm transmission capacity on the cable at market-based rates.[99] TransÉnergie emphasized that, "unlike traditional utilities recovering construction costs from their captive customers, investors in its project would assume the full market risk and were not in a position to exercise market power."[100]

To justify its request, TransÉnergie asserted that its "negotiated rates that will essentially reflect location-differential costs for competitive generation sales between the New York and New England markets."[101] TransÉnergie proposed to conduct an

95. *TransÉnergie I*, 91 F.E.R.C. at 61,835; *see also Chinook*, 126 F.E.R.C. at P 33 n.16 (stating that the first merchant transmission owner's application for negotiated rates was granted in June 2000) (citing *TransÉnergie I*, 91 F.E.R.C. ¶ 61,230).

96. The term "direct current" refers to "[e]lectricity that flows continuously in one direction, as contrasted with alternating current." EDISON ELEC. INST., GLOSSARY OF ELECTRIC INDUSTRY TERMS 43 (2005), *available at* http://www.eei.org/meetings/Meeting%20Documents/TWMS-26-glossry-electerm.pdf.

97. *TransÉnergie I*, 91 F.E.R.C. at 61,835.

98. *Id.*

99. *Id.* at 61,835.

100. *Id.* at 61,836.

101. *Id.*

open season for the initial subscription of firm transmission rights, followed by an auction for any unsubscribed rights. TransÉnergie provided a number of reasons why it would not be able to exercise market power, including the following: (1) the generation markets are competitive on each end of the line, while the new facilities would not constrain these competitive conditions and may serve to increase generation in those markets; (2) the initial allocation of firm transmission rights would be pursuant to a non-discriminatory open season; (3) it will not allow any of its affiliates to participate in the initial open season process; (4) after the open season, it will post and offer available firm transmission rights for sale on its Open-Access Same-Time Information System ("OASIS"); (5) physical access to the project will be provided in a non-discriminatory manner via scheduling and dispatch by NYISO and ISO-NE.[102]

The Commission conditionally approved TransÉnergie's proposal to provide service over the Cross-Sound Cable at negotiated rates reflecting the location-differential prices between ISO-NE and NYISO.[103] According to the Commission, the project would benefit producers and consumers in both markets by enhancing competition and market integration and expanding capacity and trading opportunities, while imposing no cost or risk on captive customers.[104]

In granting negotiated rate authority for the proposed project, the Commission accepted the applicant's explanation that "[s]ince TransEnergies [sic] proposal permits parties with firm transmission rights to arbitrage the generation prices between New Haven and Long Island, the negotiated rates will essentially

102. *Id.*

103. *TransÉnergie I*, 91 F.E.R.C. at 61,839. Among the conditions on approval of the project, the Commission required TransÉnergie to make the following compliance: provide the specific method it proposed to use in its open season; file the results of the open season 30 days after its close and specify the procedures for customers to use to reassign firm transmission rights; and join a regional transmission organization adjacent to or containing the geographic area of its project. *See id. at* 61,289; *see* TransÉnergie U.S., Ltd. (*TransÉnergie II*), 91 F.E.R.C. ¶ 61,347, 62,167 (2000) (accepting for filing TransÉnergie's description of its open season process and accepting reports on open season, procedures for reassignment of transmission rights and proposed standards of conduct).

104. *TransEnergie I*, 91 F.E.R.C. at 61,838.

be limited to the difference between the location-based marginal prices in the New York and New England markets."[105] In other words, customers would pay no more for transmission service over the merchant transmission line than the difference between the generation prices at each end of the transmission line, i.e., the difference between the locational marginal prices in the two ISOs that the merchant line interconnects. The Commission further justified granting negotiated rates based on the fact that any customer in either of those markets could request that the ISO expand its transmission facilities to provide service at cost-based transmission rates. This provided an expansion cost cap on TransÉnergie's rates.[106]

Notably, while TransÉnergie had requested market-based rates because it considered its project to be more akin to a new merchant generation plant than to a traditional transmission investment, the Commission declined to address this issue.[107] Instead, the Commission found it appropriate to approve TransÉnergie's proposal to provide service under negotiated rates as being consistent with existing transmission pricing methodologies.[108] As the Commission explained, it had "long permitted" transmission owners to charge the higher of embedded cost or opportunity pricing for transmission service.[109] For a

105. *Id.*

106. *Id.* at 61,839.

107. *Id.* at 61,838.

108. *Id.* The demarcation between market-based rates and negotiated rates is not crystal clear, and the distinction may in part reflect the 1996 Alternative Pricing Policy Statement classification of market-based rates (applicant lacks market power and there is no recourse rate) and negotiated rates (no need to prove lack of market power as long as there is a recourse rate). In general, the term "market-based rates" implies a competitive market where neither buyer nor seller has significant market power (or has adequately mitigated market power) whereas the term "negotiated rates" implies a bilateral negotiated transaction between two parties. *See* Tejas Power Corp. v. FERC, 908 F.2d 998, 1004 (D.C. Cir. 1990).

109. *TransÉnergie I*, 91 F.E.R.C. at 61,838 (citing Pa. Elec. Co., 58 F.E.R.C. ¶ 61,278, *reh'g denied,* 60 F.E.R.C. ¶ 61,034, *reh'g denied,* 60 F.E.R.C. ¶ 61,244 (1994), *aff'd* Pa. Elec. Co. v. FERC, 11 F.3d 207 (D.C. Cir. 1993)); *see* Jeffrey D. Watkiss & Douglas W. Smith, *The Energy Policy Act of 1992 – A Watershed for Competition in the Wholesale Power Market*, 10 YALE J. ON REG. 447, 477 (1993). The Commission's pricing policy is generally referred to as the higher of embedded cost or incremental cost, aptly described as follows:

vertically-integrated utility,[110] where the utility sells both transmission and generation, opportunity costs are the costs incurred when the utility foregoes opportunities to reduce generation costs to serve its customers as a result of providing transmission service to a third party instead of using it to serve its own customers.[111] According to the Commission, a "significant tenet" of its opportunity cost pricing policy is that prices should be capped at the transmission provider's cost of expansion of its system.[112] This means that where congestion costs [113] exceed the cost of expansion, expansion is the cheaper option, and the transmission provider should therefore expand its system.[114] Acknowledging that TransÉnergie, as a merchant transmission provider with no energy customers to serve, is in a different position because opportunity costs cannot be based on

> Under that model, the transmitting utility is entitled to recover operating costs, plus the capital costs of dedicated enlargements (e.g., radial lines or other facilities used exclusively for the wheeling service [citation omitted]), plus an allocable share of the capital costs of the transmission system equal to the greater of embedded cost or incremental cost; for purposes of this last cost component, incremental cost is defined as the lesser of the cost of expanding the system or the opportunity costs the transmitting utility incurs in order to provide the requested service. Where the transmission system of the transmitting utility is not constrained – i.e., where there is sufficient unused capacity to provide the requested transmission – incremental costs will ordinarily be lower than embedded cost and the resulting rate will recover only the embedded capital cost of the transmission facility. Where constraints exist, however, incremental costs (either expansion cost or opportunity cost) may exceed embedded cost.

Watkiss & Smith, *supra*, at 477.

110. A vertically-integrated utility generally refers to an electric utility that owns generation, transmission, and distribution facilities. "When a single company owns the entire system – from the generator to your meter – and sells you the power made in its generators, it is said to be *vertically integrated*." PETER FOX-PENNER, *supra* note 4, at 10.

111. *TransÉnergie I*, 91 F.E.R.C. at 61,838.

112. *Id.*

113. Congestion is defined as "[t]he condition that occurs when transmission capacity is not sufficient to enable safe delivery of all scheduled or desired wholesale electricity transfers simultaneously." U.S. DEP'T OF ENERGY, NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY 67 (2006), *available at* http://www.oe.energy.gov/DocumentsandMedia/ Congestion_Study_2006-10.3.pdf.

114. *TransÉnergie I*, 91 F.E.R.C. at 61,838-39.

the transmission provider's generation costs, the Commission nevertheless found opportunity costs to be either the generation savings of the electricity customers served by TransÉnergie's stand-alone transmission line or the savings provided by customers' other alternatives, such as new generation.[115] As noted above, the Commission further found that the expansion cost cap is provided by the obligation of the independent system operators that flank the project to expand at cost-based rates to meet new requests for transmission service – including facilities to provide service across Long Island Sound.[116] Based on this line of reasoning, the Commission concluded that TransÉnergie 's pricing proposal constituted a form of opportunity pricing, which, "in this situation, is a logical extension of our prior [transmission pricing] policy."[117]

While TransÉnergie originally proposed to construct a 600 MW line, the final capacity of the line was about half the size, at 330 MW.[118] Through the open season process, the entire transmission capacity was awarded in a 20-year contract to what is now Long Island Power Authority.[119] The project was completed in July 2002 and emergency operations began on August 14, 2003, after the 2003 blackout.[120]

In its application, TransÉnergie proposed a set of seven "safe harbor" criteria for evaluating merchant transmission projects.[121]

115. *Id.* at 61,838. This reflects the theories of economist Bill Hogan. *See* WILLIAM W. HOGAN, MARKET-BASED TRANSMISSION INVESTMENTS AND COMPETITIVE ELECTRICITY MARKETS 1 (1999) ("A short-term electricity market coordinated by a system operator provides a foundation for a competitive electricity market. In this setting, locational price differences define the opportunity cost of transmission."), *available at* http://www.hks.harvard.edu/fs/whogan/tran0899.pdf.

116. *TransÉnergie I*, 91 F.E.R.C. at 61,838.

117. *Id.* (citing Cal. Indep. Sys. Operator Corp., 89 F.E.R.C. ¶ 61,153, 61,436 (1999) (involving opportunity costs for short-term firm transmission rights)).

118. *See TransÉnergie I*, 91 F.E.R.C. at ¶ 61,230; *see* Cross-Sound Cable Co., 109 F.E.R.C. ¶ 61,223, at P 2 (2004).

119. TransÉnergie U.S., Ltd. (*TransÉnergie III*), 93 F.E.R.C. ¶ 61,289, 61,971 (2000).

120. Cross-Sound Cable Co., 109 F.E.R.C. ¶ 61,223 at P 25.

121. *See TransÉnergie I*, 91 F.E.R.C. ¶ 61,230, 61,837. TransÉnergie proposed that the merchant transmission facility should: assume full market risk; create tradable transmission rights; use an open-season process initially to allocate transmission rights; not preclude access to essential facilities by competitors; be

The Commission used these criteria plus an additional criterion to assess TransÉnergie's application, as well as subsequent applications,[122] and they became the foundation for the ten criteria the Commission used to assess merchant transmission provider applications for negotiated rate authority for nearly a decade.

The ten criteria or "guideposts" used to assess whether it is just and reasonable to grant negotiated rate authority to a merchant transmission project are the following: (1) assumption of market risk: the merchant transmission facility must assume full market risk; (2) Open Access Transmission Tariff: operational control of the facility should be turned over to a neighboring ISO/RTO and the transmission service should be provided under that ISO's or RTO's Open Access Transmission Tariff; (3) secondary transmission rights: the merchant transmission facility should create tradable firm secondary transmission rights; (4) open season: an open season process should be used initially to allocate transmission rights; (5) open season report: the open season results should be posted on the OASIS and filed in a report to the Commission; (6) affiliate concerns: affiliate concerns should be adequately addressed (no undue discrimination); (7) access to essential facilities: the merchant transmission facility should not preclude competitors' access to essential facilities; (8) market monitoring: the merchant transmission facilities should be subject to market monitoring for market power abuse; (9) reliability requirements: physical power flows on merchant transmission facilities should be coordinated with, and subject to, the relevant RTO or independent system operator's reliability requirements; and (10) preexisting property rights: merchant transmission facilities should not impair pre-existing property rights to use the transmission grids of interconnected utilities or RTOs.[123]

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subject to market monitoring for market power abuse; coordinate physical energy flows on merchant transmission facilities with and subject to reliability requirements of the relevant ISO or RTOs; and not impair pre-existing property rights to use the transmission system or inter-connected RTOS or utilities. *Id.*

122. *See, e.g.*, *Neptune I*, 96 F.E.R.C. ¶ 61,147, 61,633 (2001).

123. Sea Breeze Pacific San Juan de Fuca Cable (*Sea Breeze*), 112 F.E.R.C. ¶ 61,295, at P 16 (2005) (citing Ne. Utils. Serv. Co. (*NUSCO I*), 97 F.E.R.C. ¶ 61,026 (2001)).

2. Neptune: Open Season

Neptune proposed to build merchant transmission facilities that would connect, through undersea high-voltage, direct current lines, the capacity-rich regions of Maine, New Brunswick, and Nova Scotia with the capacity-deficient regions of Boston, New York City, Long Island, and Connecticut.[124] The Commission evaluated Neptune's application under the *TransÉnergie* criteria and conditionally approved Neptune's request. Pointing out that that Neptune was willing to assume all the risk of the project and proposed to establish rates that would be "effectively capped by market forces,"[125] the Commission determined that the project could "play a useful role in expanding competitive generation alternatives for customers."[126] However, the Commission rejected both Neptune's proposal to provide service under a stand-alone tariff and its request for a waiver of the requirement to provide service under an Open Access Transmission Tariff. Instead, as in *TransÉnergie*, the Commission conditioned approval of the application on Neptune joining an RTO or ISO adjacent to or containing the proposed project and placing those facilities under the transmission organization's operational control.[127]

Significantly, Neptune brought the open season issue to the fore. Neptune proposed to allocate at least eighty percent of the project's capacity for long-term service, through transmission scheduling rights with duration of one year or longer. All of the remaining capacity would be available on a short-term basis and sold in the open seasons administered by the RTO.[128] Neptune argued that these short-term open seasons would provide a check on potential exercise of market power by long-term capacity holders because the short-term prices would limit the price at which the long-term capacity could be resold on the secondary

124. *Neptune I*, 96 F.E.R.C. ¶ 61,147, 61,629 (2001).
125. *Id.* at 61,633.
126. *Id.*
127. *Id.* Note that Neptune's application was submitted during a time when there was the possibility that there would be one Northeastern RTO. *See id.*
128. *Id.* at 61,631.

market.[129] They would also ensure that some generation would have the opportunity to use Neptune's system in competition with long-term capacity holders. In addition, Neptune originally proposed to negotiate bilateral agreements with large customers for up to thirty percent of the capacity of the project prior to holding an open season.[130] Neptune asserted that this would provide assurance of adequate interest in the project, giving it "legitimacy and momentum."[131] Neptune argued that these bilateral contract rates would be capped by the same market forces – the purchaser's opportunity costs – that would cap rates during the open season.[132]

The Commission rejected this feature of its proposal, reasoning that if the project is economically viable, Neptune should be able to obtain binding financial commitment through open season contracts.[133] Also, because the prices would be effectively capped by the same forces prior to and during the open season, there was no ostensible benefit to Neptune negotiating thirty percent of its capacity pre-open season.[134] Moreover, the Commission declared that, as a matter of policy, all capacity for merchant transmission projects should be made available through open seasons to ensure its allocation is "transparent, nondiscriminatory and fair."[135]

Neptune responded by insisting that an open season was not essential to ensuring "transparent, non-discriminatory and fair" access to capacity on its project, and that market forces would dictate that no purchaser pays more than opportunity costs, regardless of whether capacity rights are purchased through pre-open season negotiated transactions or open seasons.[136] This is particularly true, Neptune argued, because it lacks captive customers and is assuming all market risk of the project.[137]

129. *Id.*
130. *Neptune I*, 96 F.E.R.C. at 61,633-34.
131. *Id.* at 61,634.
132. *Id.* at 61,633-34.
133. *Id.* at 61,634.
134. *Id.* at 61,633-34.
135. *Id.* at 61,634.
136. Neptune Reg'l Transmission Sys. (*Neptune II*), 103 F.E.R.C. ¶ 61,213, at P 11 (2004).
137. *Id.*

Neptune further claimed that it had no incentive to discriminate among market participants during its negotiations.[138] To support their position, both Neptune and intervenor TransÉnergie drew comparisons with gas regulation. TransÉnergie pointed out that gas pipelines can pre-sell capacity prior to holding an open season; precluding merchant transmission from pre-selling their capacity limits their ability to allay risk and hampers project development.[139] Neptune complained that bidders in pipeline open seasons only compete on price, subject to the applicable cost-based cap (recourse rate) because other terms and conditions are already included in the pipeline's tariff. In contrast, Neptune's open season bidders' terms and service were less clearly spelled out, needed to be negotiated, and also to be provided under the (as yet unknown) terms of the Open Access Transmission Tariff of an (as yet to be created Northeastern) ISO/RTO. These complicating factors, Neptune insisted, made interested customers less willing to participate in its open season.[140]

The Commission denied rehearing and continued to reject Neptune's pre-open season contracting proposal.[141] Emphasizing that the transparency afforded in the open season is essential to ensuring all parties are treated fairly, the Commission declared that it was "not ready to abandon its policy that all initial transmission rights must be sold through an open season."[142] The Commission found this particularly important where it allowed affiliates to participate in the open season, as it did for Neptune.[143] The Commission nevertheless signaled its willingness to consider "other options" to assist merchant transmission providers in their quest for innovative ways to add transmission to the grid and secure financing for their projects.[144]

Pointing to its approval of a four-part open season as one example, the Commission also suggested Neptune broaden its criteria for evaluating transmission capacity bids and offered up

138. *Id.* at P 12.
139. *Id.* at P 16.
140. *Id.* at P 15.
141. *Id.* at P 17.
142. *Neptune II*, 103 F.E.R.C. ¶ 61,213 at P 17.
143. *Id.*
144. *Id.* at P 18.

the possibility of developing standard transmission scheduling rights contracts.[145] Notably, it also signaled its willingness to reconsider the open season issue for initial allocation of project rights where equity investors and other affiliates do not participate.[146]

3. Northeast Utilities Service Company: Appeasing Affiliate Concerns

Similar to its predecessors TransÉnergie and Neptune, Northeast Utilities Service Company ("NUSCO") requested the Commission approve negotiated transmission rates on an undersea, high-voltage direct-current cable linking New England and New York.[147] Unlike its predecessors, however, NUSCO was affiliated with and controlled the facilities of the regulated entity to which it proposed to connect.[148] On its first pass, the Commission rejected the pricing proposal, with specific suggestions.[149] Citing NUSCO's lack of explanation whether any affiliated or unaffiliated entity could connect new transmission facilities to the project, the Commission emphasized that neither NUSCO nor its affiliates should be able to delay competitors from interconnecting with the project of the ISO at each end.[150] Also pointing out that, unlike NUSCO, neither TransÉnergie nor Neptune was in a position to shift risk to captive customers, the Commission required NUSCO to describe in detail the procedures used to ensure that NUSCO assumes full market risk for the project, including accounting procedures and codes of conduct.[151] The Commission was also troubled by NUSCO's proposal to include its affiliates in the open season for allocating transmission rights, whereas TransÉnergie and Neptune (originally) had prohibited their affiliates from such

145. *Id.*
146. *Id.*
147. *NUSCO I*, 97 F.E.R.C. ¶ 61,026, 61,071 (2001); Ne. Utils. Serv. Co. (*NUSCO II*), 98 F.E.R.C. ¶ 61,310, 62,326 (2002).
148. *NUSCO I*, 97 F.E.R.C. at 61,074.
149. *Id.* at 61,074-75.
150. *Id.* at 61,074.
151. *Id.*

participation.[152] Consequently, finding the application raised "significant affiliate issues," market power issues such as barriers to entry and assumption of risk, concerns regarding the open season process and business risk criteria in the application, the Commission found the filing deficient and required NUSCO to provide additional detail.[153] The Commission also rejected NUSCO's proposal for its subsidiary to provide service on a stand-alone rate schedule, instead finding that, consistent with TransÉnergie and Neptune, service should be provided under the terms and conditions of the Open Access Transmission Tariff ("OATT") of the RTO that would operate the project.[154]

The Commission ultimately conditionally accepted NUSCO's application for negotiated rates, after the company submitted additional information and revised aspects of its proposal, including no longer permitting its affiliates to participate in open seasons.[155] However, plans for what would have been this 300 MW line were withdrawn in November 2002, after a disappointing open season.

B. Transitional cases

TransÉnergie and other early merchant transmission applicants were located in or adjacent to RTOs and ISOs.[156] The criteria or "guideposts" the Commission crafted to assess negotiated rate applications took this factor into account, and the precedent discussed above conditioned negotiated rate authority on turning facilities over to an RTO to operate and to facilitate non-discriminatory open access.[157]

Within the past five years, however, requests for negotiated rate authorization for merchant transmission projects located

152. *Id.* at 61,074-75.

153. *See id.* at 61,071.

154. *See NUSCO I*, 97 F.E.R.C. at 61,075.

155. *See NUSCO II*, 98 F.E.R.C. at 62,329. However, plans for what would have been this 300 MW line were withdrawn in November 2002, after a disappointing open season. *See id.* at 62,328 n.10.

156. *See Chinook*, 126 F.E.R.C. ¶ 61,134, at P 35 (2009).

157. *See, e.g.*, *TransÉnergie I*, 91 F.E.R.C. ¶ 61,230, 61,840 (2000); *Neptune I*, 96 F.E.R.C. at 61,633; *NUSCO I*, 97 F.E.R.C. at 61,075.

outside the footprint of an RTO or ISO have increased.[158] This development is at least partially attributable to the increased development of generation from renewable resources and the fact that these resources are often located in areas that are remote from customers.[159] In *Sea Breeze*,[160] the Commission granted a request to charge negotiated rates for transmission service over a 22-mile, 540 MW high voltage direct current transmission line (and converter stations) that would run underneath the Strait of San Juan de Fuca between Washington State and British Columbia, Canada. In *MATL*,[161] the Commission granted a request to charge negotiated rates for a merchant line that would run from Lethbridge, Alberta, Canada to Great Falls, Montana. In each case the applicant used the ten criteria as a framework to present its proposal, noting the distinction from prior cases that involved organized markets. In both cases, the Commission either waived certain criteria or applied them flexibly, and signaled its receptivity to reconsidering the relevance of all ten

158. *See, e.g.*, *Champlain*, 132 F.E.R.C. ¶ 61,006, at P 3 (2010) (proposing to connect locations in Montreal, Quebec, New York City and New England); *SunZia*, 131 F.E.R.C. ¶ 61,162, at P 2 (2010) (proposing to connect sites in New Mexico and Arizona); *Tres Amigas I*, 130 F.E.R.C. ¶ 61,207, at P 4 (2010) (proposing to connect in New Mexico all three interconnections in the continental United States); Mountain States Transmission Intertie, L.L.C. (*Mountain States*), 127 F.E.R.C. ¶ 61,270, at P 3 (2009) (proposing to connect locations in Montana and Idaho); Wyo. Colo. Intertie, L.L.C., 127 F.E.R.C. ¶ 61,125, at P 2 (2009) (proposing to connect Western Area Power Administration with Public Service Company of Colorado); *Chinook*, 126 F.E.R.C. ¶ 61,134 at P 2 (proposing to connect locations in Idaho and Nevada and Montana and Nevada); *MATL*, 116 F.E.R.C. ¶ 61,071, at P 2 (2006) (proposing to connect locations in Canada and Montana); *Sea Breeze*, 112 F.E.R.C. ¶ 61,295, at P 2 (2005) (proposing to connect locations in Washington state and British Columbia).

159. *See MATL*, 116 F.E.R.C. ¶ 61,071 at P 24 (finding MATL proposed "an innovative merchant transmission project that will provide a link between two regions and allow for efficient and economic access to existing and new generation sources, such as newly developing wind farms.").

160. *See Sea Breeze*, 112 F.E.R.C. ¶ 61,295 at P 24 (citing *NUSCO I*, 97 F.E.R.C. ¶ 61,026 (2001)).

161. *See MATL*, 116 F.E.R.C. ¶ 61,071 at P 24 (finding MATL proposed "an innovative merchant transmission project that will provide a link between two regions and allow for efficient and economic access to existing and new generation sources, such as newly developing wind farms.").

criteria for these types of projects.[162] For example, the Commission allowed each of these applicants to serve customers under their respective OATTs.

Also noteworthy, lacking an RTO on each end to "discipline" or cap negotiated rates, the Commission justified granting MATL negotiated rate authority on slightly different grounds than it had in prior cases. The Commission found that MATL's open season process, in which it auctioned off over half of the project's capacity, coupled with the fact that it agreed to be a price taker (bid in at zero, willing to take the auction clearing price), subject to a floor defined by the current auction price, would result in transmission rights being auctioned in an open, fair and transparent manner at a price approximating the current costs of capital, construction and operation initial rates for capacity.[163] As for MATL's rates for transmission capacity going forward, similar to its rationale in the RTO context, the Commission explained that NorthWestern Energy has an obligation under its OATT, if requested, to expand capacity at cost-based rates in or near the region served by MATL. Consequently, the Commission reasoned, MATL's customers would be "likely to pay prices that are no higher than, and probably lower than, Northwestern [sic] Energy's cost of expansion."[164] The applicant argued that the prices would be limited to the differential between the power markets in Montana and Alberta.

162. *See Sea Breeze,* 112 F.E.R.C. ¶ 61,295 at P 17, 22, 27, 32; *see MATL*, 116 F.E.R.C. ¶ 61,071 at P 27, 32, 35.

163. *See MATL*, 116 F.E.R.C. ¶ 61,071 at P 53.

164. *See id.* The Commission also pointed out that this is the same approach it had initially taken when authorizing market-based rates for certain sellers of ancillary services, relying on cost-based rates of transmission providers to limit the prices charged by competitors. *Id.* (citing Avista Corp., 87 F.E.R.C. ¶ 61,223 (1999), *order on reh'g,* 89 F.E.R.C. ¶ 61,136 (1999)). Note that the applicant had argued that the prices would be limited to the differential between the power markets in Montana and Alberta. *See id.* at P 54 (the Commission did not discuss this rationale in its determination).

C. Recent Developments: FERC's Flexible Four-Factor Test

After gaining experience with evaluating proposals for negotiated rate authority for merchant transmission projects located outside the footprint of organized markets, the Commission ultimately settled on a streamlined, flexible approach that it concluded would facilitate financing for such projects.

1. Chinook and Zephyr

In the landmark order on Chinook Power Transmission, L.L.C. and Zephyr Power Transmission L.L.C., the Commission: (1) whittled its ten factor-test for authorizing negotiated, rather than cost-based, rates for transmission down to a simpler, more flexible, four-factor test;[165] and (2) departed from prior electricity precedent and borrowed from the natural gas model to allow project developers to pre-subscribe fifty percent of project capacity to anchor customers before holding open season auctions to allocate the remainder of the capacity.[166] While, as discussed above, the Commission had rejected pre-open season contracting in a prior case, *Neptune,* the Commission modified its policy to help merchant transmission developers surmount the practical difficulties they face in financing large projects.[167] In *Chinook*, the Commission concluded that the financial commitments made by anchor customers prior to an open season gave merchant transmission providers crucial early support and certainty,

165. *See Chinook*, 126 F.E.R.C. ¶ 61,134, at P 37 (2009).

166. *See id.* at P 60. The Commission subsequently allowed as much as 75 percent of capacity to be presubscribed before an open season. *See Champlain*, 132 F.E.R.C. ¶ 61,006, at P 45 (2010) (granting request to charge negotiated rates for transmission rights on a high voltage direct current merchant transmission project linking Montreal, Quebec to the New York City and New England area markets). The Commission allowed presubscription of 75 percent capacity in 30-year contracts to help Champlain secure financing, including $3 billion ARRA loan guarantee from DOE and $800 million private equity; and (2) given the project's specifics, such as few potential open season participants, and the applicants' commitments, including posting of winning bidders, keeping books and records, filing financial reports and having its books and records audited by an independent auditor. *Id.* at P 46.

167. *See Chinook*, 126 F.E.R.C. ¶ 61,134 at P 44.

enabling them to gain the critical mass necessary to develop these projects.[168] The Commission emphasized that this approach may be particularly beneficial for location-constrained resources.[169] While the Commission signaled its willingness to be more flexible regarding capacity allocation outside of the open season context, the FPA provided the limits on this flexibility, by precluding merchant transmission developers from allocating transmission capacity in an unduly discriminatory manner.[170]

a. Description of the Chinook and Zephyr Projects

Chinook proposed to construct a 1000-mile, 500 kV high-voltage direct current transmission line that would originate in Montana and terminate south of Las Vegas, Nevada.[171] Zephyr proposed to develop a 1100-mile, 500 kV high-voltage direct current transmission line from Wyoming to south of Las Vegas, Nevada.[172] The developers asserted their projects would benefit the western power grid by providing transmission capacity to transmit approximately 3000 MW of wind-generated electricity to load centers in the southwestern United States.[173] The proposed transmission lines, which would cost approximately three billion dollars each, would run parallel to each other along the southern portions of Borah, Idaho, to their termination points south of Las Vegas.[174] Converter stations, to change alternating current to direct current and back, would be located at the lines' respective origin, terminus, and in Idaho and Nevada.

b. Presubscription and Open Season

To defray expenses, Chinook and Zephyr each entered into an agreement with a wind generation developer to become an

168. *See id.*
169. *See id.*
170. *See id.*
171. *See id.* at P 2.
172. *See id.*
173. *See Chinook*, 126 F.E.R.C. ¶ 61,134 at P 2-3.
174. *See id*

"anchor customer" and share developmental costs.[175] Chinook and Zephyr explained that extensive discussions with numerous prospective customers confirmed the need for the project, but no one was willing to commit without demonstrable commercial support.[176] They argued that in the current financial climate, the projects would not move forward without anchor customers.[177]

Consequently, they proposed to subscribe fifty percent of the transmission rights to their project to their respective anchor customer and then hold open seasons to auction the remaining 1500 MW of capacity for each line.[178] They argued that pre-subscription of at least fifty percent of each project prior to conducting an open season was needed to ensure commercial viability.[179] They asserted that this amount "strikes a reasonable balance between satisfying commercial objectives and still providing all other customers an opportunity to bid for capacity in the open season."[180] A precedent agreement with one large customer, they insisted, would simplify negotiations and expedite the development process.[181] They warned that pre-subscriptions with multiple small entities would increase the risk that one or more entities would back out, leaving Chinook and Zephyr contractually committed to other entities, but lacking support needed to complete the projects.[182]

Chinook and Zephyr asserted that the anchor customers' precedent agreements would be used as a model for the open season customers' precedent agreements and that any customer in the open season willing to commit to a twenty-five-year term for any megawatt amount would receive the same rate and terms as the anchor customers.[183] They proposed that if there were more successful bids than transmission capacity, they would

175. *See id.* at P 10.
176. *See id.*
177. *See id.*
178. *See id.*
179. *See Chinook*, 126 F.E.R.C. ¶ 61,134 at P 12.
180. *See id.*
181. *See id.*
182. *See id.*
183. *See id.*

either prorate the awarded open season capacity rights or enlarge the projects, if feasible.[184]

c. Lack of Market Power and Negotiated Rate Authority

Chinook and Zephyr contended that they lacked market power and only willing potential customers would seek transmission rights on these lines.[185] They pointed out that they are merchant transmission developers with no captive customers and, as they are located outside of an organized market, i.e., not located in an RTO or ISO, there are no members of those organizations to subsidize any costs of the proposed projects.[186] Chinook and Zephyr argued that there are a number of proposed projects in the Western Interconnection that will compete with these projects and customers will not sign onto a project that does not offer competitive transmission prices.[187] They asserted that this guarantees that the negotiated rates will be just and reasonable.[188] They further asserted that customers will be protected by incumbent transmission providers' obligations to expand capacity upon request in the vicinity of the projects and the availability of cost-based transmission rates for service over such expansions.[189] They contended that customers are likely to pay prices no higher than the neighboring transmission providers' expansion costs.[190] In addition, they asserted that the anchor shipper selection process and open season commitments ensure the "open, fair and transparent" allocation of transmission rights at a price around the current cost of construction, operation and capital.[191]

184. *See id.*
185. *See Chinook*, 126 F.E.R.C. ¶ 61,134 at P 17.
186. *See id.*
187. *See id.*
188. *See id.*
189. *See id.*
190. *See id.*
191. *See Chinook*, 126 F.E.R.C. ¶ 61,134 at P 18.

d. Commission Disposition: The Four-Factor Test

Significantly, in *Chinook,* the Commission consolidated and refined the ten criteria for granting negotiated rate authority for merchant transmission projects, particularly where the criteria did not suit merchant transmission projects located outside the footprint of an organized market.[192] Declaring an "evolution in the Commission's policy," the Commission jettisoned the requirement that all initial capacity must be allocated through a pre-construction open season, which had formerly precluded use of the anchor shipper model used in the natural gas context.[193] Acknowledging the practical difficulties merchant transmission developers face in financing large projects – including the "chicken-and-egg problem" that generators, purchasers and transmission owners are all loathe to be the first to commit to a project – the Commission concluded that anchor shippers' financial commitments prior to an open season could provide "crucial early support and certainty to merchant transmission developers, which enables them to gain the critical mass necessary to develop these projects."[194]

The revised four-part analysis focuses on the following four "areas of concern:" (1) justness and reasonableness of rates; (2) potential for undue discrimination;[195] (3) potential for undue preference, including affiliate preference; and (4) regional reliability and operational efficiency requirements.[196] The first three factors track the requirements of section 205 of the FPA,

192. *See id.* at P 37. The Commission explained its intent was to "'re-focus' the Commission's analysis on the mandate of section 205 and the underlying areas of concern that the Commission seeks to address in its evaluation of negotiated rate applications for merchant transmission projects." *Id.* at P 37.

193. *See id.* at P 42.

194. *See id.* at P 44 (citing comments in Docket No. AD08-13). Note that the Commission's rationale reflects Neptune's prior arguments attempting to persuade the Commission to allow pre-open season contracts. In *Chinook,* the Commission also pared down the requirement that facilities must be turned over to an RTO/ISO. *Id.*

195. Generally speaking, "[d]iscrimination is undue when there is a difference in rates or services among similarly situated customers that is not justified by some legitimate factor." El Paso Natural Gas Co., 104 F.E.R.C. ¶ 61,045, at P 115 (2003).

196. *See Chinook*, 126 F.E.R.C. ¶ 61,134 at P 37.

and the fourth factor reflects the imperative that transmission be reliable (EPAct 2005 enhanced this authority) and efficient.[197] In evaluating whether negotiated rates are just and reasonable, the Commission announced that it will take into consideration: whether the merchant transmission owner assumed the full market risk and is not building within the region of its own or affiliate's transmission system, to assure there are no captive customers to subsidize the project. The Commission will also consider whether the merchant transmission developer: already owns transmission facilities in the region where the project will be located and what alternatives customers have; is capable of erecting barriers to competitors' entry; and would have any incentive to withhold capacity.[198] The Commission further reiterated its prior rationale for approving negotiated rates:

> For example, negotiated rates may be appropriate when the service on a neighboring public utility under cost-of-service rates – essentially capped at the utility's cost of expansion – can provide a reasonable alternative. A further check on the negotiated rates could exist where the price customers are willing to pay for transmission service is disciplined by the difference in generation prices at the ends of the line (i.e., the market price of generation on either side of the line).[199]

Merchant transmission providers retaining ownership and control of their projects are still required to create firm tradable secondary transmission rights, as well as an OASIS through which customers may buy and sell those rights.[200]

As for the second area of concern, preventing undue discrimination, the Commission stated that it primarily considers the following two factors: (1) the merchant transmission provider's open season; and (2) its OATT commitments (or, commitment to turn operational control over to the RTO/ISO,

197. *See id.* at P 53 (explaining that "[b]ecause merchant transmission is subject to mandatory reliability requirements, separate reliability requirements no longer seem necessary.") (citation omitted).

198. *See id.* at P 38.

199. *See id.* at P 38 n.26.

200. *See id.* at P 39.

where applicable).[201] The Commission explained that, to the developer, open seasons are important for determining the extent of interest in the project and whether the project needs to be resized.[202] For customers, open seasons must be "fair, transparent and non-discriminatory,"[203] and the Commission declared that it would continue its practice of requiring developers to file reports shortly after holding an open seasons, to provide transparency in the initial allocation of transmission rights as well as the basis for an entity to file a complaint alleging undue discrimination.[204] At a minimum, the reports are to include the terms of the open season, including the notice period, the identity of the party (or parties) that purchased capacity; and the price, amount and term of capacity purchase.[205] The open season reporting requirement and customer complaints will continue to be the main tools for preventing merchant transmission developers from unduly discriminating among potential customers.[206]

Notably, the Commission acknowledged that its one hundred percent allocation of initial capacity in a pre-construction open season requirement had become "unduly rigid and inflexible."[207] The Commission stated that it would evaluate on a case-by-case basis any proposal to allocate some or all initial capacity outside of an open season, reasoning that its continued reliance on the post-open season reporting requirement and complaint process should provide sufficient transparency and protection to customers where the merchant transmission owner presubscribes a portion of its capacity to an anchor customer.[208]

After the pre-construction open season, merchant transmission projects located in or adjacent to RTOs/ISOs are "to consider" turning over operational control of their facilities to the RTO/ISO; merchant transmission developers not located in or

201. *See id.*
202. *See Chinook*, 126 F.E.R.C. ¶ 61,134 at P 41.
203. *Id.*
204. *See id.* at P 43.
205. *See id.*
206. *See id.* at P 45.
207. *Id.* at P 42.
208. *See Chinook*, 126 F.E.R.C.¶ 61,134 at P 45-49.

within the vicinity of an RTO/ISO must file and provide non-discriminatory service pursuant to an Order 890-compliant OATT. Any deviations from the *pro forma* OATT will be considered on a case-by-case basis, as it had in *MATL*.[209]

The third factor, undue preference and affiliate concerns, is implicated when the merchant transmission owner is affiliated with either the anchor customer, open season participants, and/or customers that take service on the merchant transmission facility.[210] In particular, the Commission emphasized that it will apply a "higher level of scrutiny" when the anchor shipper is affiliated with the merchant transmission developer out of concern that the affiliate's captive ratepayers could subsidize the merchant project inappropriately.[211] Similarly, while not imposing a blanket prohibition on affiliates from participating in open seasons, the Commission nevertheless expressed concern that affiliates could be offered unduly lower rates than non-affiliates or that the merchant transmission developer could charge higher rates to a regulated entity with captive customers, harming captive customers by compelling them to subsidize the project, as well as effectively blocking entry by other merchant transmission developers, thus limiting competition.[212] For post-open season purchases of transmission rights on the merchant line, the Commission requires all transactions to be transparent and posted on the relevant entity's OASIS.[213]

As for the fourth criterion, regional reliability and operational efficiency, the Commission explained that these concerns had been its impetus for requiring merchant transmission developers to turn facilities over to the relevant RTO/ISO in the past.[214] However, FERC explained, now that merchant transmission providers are subject to mandatory reliability requirements, separate reliability requirements no longer seem necessary. Merchant transmission developers are required to comport with North American Electric Reliability

209. *See id.* at P 47.
210. *See id.*
211. *See id.* at P 49.
212. *See id.*
213. *See id.*
214. *See Chinook*, 126 F.E.R.C. ¶ 61,134 at P 52.

Corporation ("NERC") and any regional reliability council and are encouraged to participate in Order 890 regional planning processes.[215]

Using these four factors to assess the applications, the Commission conditionally authorized Chinook and Zephyr to charge negotiated rates for transmission rights on the respective projects: "We re-affirm our commitment to fostering the development of merchant transmission projects through our adoption of a more flexible approach toward negotiated rate applications that simultaneously acknowledges the financing realities faced by merchant transmission developers and carries out the Commission's customer-protection mandate."[216]

2. Tres Amigas

This past year, the Commission acted on a groundbreaking proposal, called Tres Amigas, which "has the potential to expand markets and to provide new and significant trading opportunities to location-constrained resources in a part of the country that is rich in potential for renewable energy development."[217] On December 8, 2009, Tres Amigas LLC ("Tres Amigas") filed a request for authorization to charge negotiated rates for transmission rights on a proposed merchant transmission project that would utilize innovative technology to link, for the first time in history, the three asynchronous transmission interconnections in the continental United States: the Eastern Interconnect, the Western Electric Coordinating Council ("WECC"), and Electric Reliability Council of Texas ("ERCOT").[218] The Project would

215. *See id.*

216. *Id.*

217. *Tres Amigas I*, 130 F.E.R.C. ¶ 61,207, at P 1 (2010), *order on motion for clarification,* 131 F.E.R.C. ¶ 61,281 (2010), *reh'g denied,* 132 F.E.R.C. ¶ 61,233 (2010).

218. On the same day, Tres Amigas also filed a related petition for disclaimer of Commission jurisdiction over the transmission facilities and entities that would interconnect the proposed Tres Amigas superstation project with ERCOT. Petition for Disclaimer of Jurisdiction, *Tres Amigas* (2009) (No. EL10-22). Historically, because ERCOT facilities are not used for transmission and sales of electricity in interstate commerce, FERC has lacked jurisdiction over ERCOT facilities, except under sections 210 and 211 of the FPA. 16 U.S.C. §§ 824i, 824j (2006). The Commission denied Tres Amigas' request to disclaim jurisdiction.

consist of a three-way alternating current (AC)/DC transmission interconnection "superstation" in New Mexico, near the Texas border. In making its pitch for negotiated rates, Tres Amigas argued that cost-based rates would not be realistic for the project because it has no captive customers, there is no RTO to recover the project costs, the beneficiaries of the project are spread throughout all three interconnections, and the project risks exceed typical cost-based project risks.[219]

On March 18, 2010, using the four-prong *Chinook* analysis, the Commission granted Tres Amigas' request for negotiated rates, "subject to a number of conditions designed to ensure that the goals of open access are protected and that the rates for transmission service on the project remain just and reasonable."[220] First, the Commission determined that Tres Amigas qualified for negotiated rates because it would be a new entrant in the regional market for transmission services, with no captive customers, and would assume full market risk of the project.[221] Articulating a voluntarism principle, the Commission emphasized that if customers voluntarily agree to take service, neighboring utilities are not obligated to construct transmission facilities to the merchant transmission project, and the project does not require mandatory use of the transmission system or impose a system benefit charge, this indicates that the developer has assumed full market risk.[222] The Commission explained that the reason it assesses whether the merchant transmission provider has assumed full market risk is to protect customers from inappropriate cross-subsidization.[223] Utilities that voluntarily decide to construct transmission facilities to the project, like existing neighboring facilities, are under no obligation to connect to or purchase service from Tres Amigas, so

Tres Amigas L.L.C., 130 F.E.R.C. ¶ 61,205, *reh'g denied*, 132 F.E.R.C. ¶ 61,232 (2010).

219. *See* Application for Authorization to Sell Transmission at Negotiated Rates and Related Relief (2009) (No. ER10-396, at 3-4).

220. *Tres Amigas III*, 132 F.E.R.C. ¶ 61,233 at P 13 n.6 (citing *Tres Amigas I*, 130 F.E.R.C. ¶ 61,207).

221. *See Tres Amigas I*, 130 F.E.R.C. ¶ 61,207 at P 51.

222. *See Tres Amigas III*, 132 F.E.R.C. ¶ 61,233 at P 18, 19, 22.

223. *Id.* at P 22.

there is no cross-subsidization of the merchant transmission project.[224]

In addition, the Commission determined that the project's negotiated rates would be just and reasonable because it found checks on Tres Amigas' ability to develop and exercise market power, singling out the following controls: the developer's commitment to expand its facilities at cost-based rates if the market will not support a merchant upgrade; the Commission's requirement that Tres Amigas seek Commission approval of its open season, via filing an independently audited post-open season report, and any anchor customer transactions.[225] The Commission also relied on Tres Amigas' various commitments, such as its promise to file an OATT that provides its open season terms and seek Commission approval prior to selling project capacity to project owners or affiliates or selling an equity interest to a utility with captive customers.[226] Furthermore, the Commission found that a number of factors would provide long-term price discipline, striking the "appropriate balance" between financing realities and long-term market power.[227]

Under the second prong, consistent with *Chinook,* the Commission granted Tres Amigas authority to enter into anchor customer agreements for up to fifty percent of the project's initial capacity.[228] However, notably, it modified the open season auction process to make available at all times all the initial capacity not purchased by an anchor customer.[229] In addition, to allay the potential for undue discrimination, the Commission required the merchant transmission developer to offer the same

224. *See id.* at P 24.

225. *See id.* at P 25.

226. *Id.*

227. *See id.* at P 26 n.54. In particular, the Commission listed the factors: competition from holders of secondary transmission rights; options to purchase capacity on existing interties, capped at the cost of expanding these interties; a new entrant's cost to construct an intertie between any or all of the interconnections; the difference in the price of generation in the markets the project connects; and the cost of expanding the project at cost of service rates once the project is built. *Id.*

228. *See Tres Amigas I*, 130 F.E.R.C. ¶ 61,207 at P 57.

229. *See id.* at P 54. Tres Amigas had proposed to withhold twenty percent. *Id.* at P 59.

rates and terms it offers to anchor customers to any customer in the open season auction.[230]

As for the third prong, the Commission concluded that the project did not present any undue preference or affiliate concerns because the applicant promised to seek prior Commission authorization for any affiliate transaction.[231] Fourth, Tres Amigas promised to participate in the Order 890 planning process and comply with WECC requirements, so the Commission determined that the project met regional reliability and operational efficiency requirements.[232]

D. Limits of Flexibility

In 2009, *Mount States Transmission Intertie, LLC*, Mountain States, a wholly-owned subsidiary of utility NorthWestern Corporation ("NorthWestern"), together with NorthWestern filed a petition for declaratory order requesting negotiated rate authority for a proposed transmission project.[233] They also proposed to give customers that were already in NorthWestern's existing transmission interconnection queue a priority on the proposed project if open season demand were to exceed the capacity of the project configuration.[234] The applicants stated that NorthWestern's existing generation capacity significantly exceeds its load, rendering NorthWestern an exporting control

230. *See id.* at P 61. The Commission subsequently clarified that Tres Amigas is only required to offer other potential customers the same rates and terms as it may negotiate with the anchor customer on a one-time basis after the anchor customer agreement has been approved by the Commission. Tres Amigas L.L.C. (*Tres Amigas II*), 131 F.E.R.C. ¶ 61,281, at P 14 (2010).

231. *See Tres Amigas I*, 130 F.E.R.C. ¶ 61,207 at P 94.

232. *See id.* at P 97.

233. *See Mountain States*, 127 F.E.R.C. ¶ 61,270, at P 1 (2009).

234. *See id.* at P 1, 7. Mountain States contemplated three potential configurations for the project: (1) a 433 mile, 500 kV line from Townsend, Montana to Borah, Idaho; (2) a 362 mile, 345 kV line from Townsend to Borah; or (3) a 268 mile, 230 kV line from Mill Creek, Montana to Borah. *See* Petition for Declaratory Order on Rate Treatments and Open Season for Transmission Export Project and Request for Expedited Treatment, at 3-5 (filed Jan. 15, 2009) (No. EL09-30-000). The developer, Mountain States, proposed to determine the ultimate size and configuration of the project through a two-stage open season that would result in binding customer commitments. *See id.* at 5, 11-12.

area.[235] Consequently, they proposed to develop the project as a stand-alone transmission system, rather than an expansion of the NorthWestern system, as previously anticipated, to protect NorthWestern's existing customers from subsidizing the cost of a new transmission facility to serve off-system markets.[236] They asserted that Mountain States had no captive customers and would assume full market and financial risk for the project.[237] Mountain States would provide transmission service under an Order 890-compliant OATT since the project would not be located within or adjacent to an RTO/ISO.[238]

PPL EnergyPlus, LLC and PPL Montana, LLC (collectively, "PPL") vigorously contested the application for negotiated rates, arguing that rather than process PPL's 2004 request for transmission service under the OATT, with cost-based rates, NorthWestern sought to force PPL to compete for transmission service at rates that would depend on the number of customers who would participate in the open season for affiliate Mountain States project and the ultimate size of the transmission facility.[239] Contending that the proposal raised affiliate concerns such as cross-subsidization as well as rate pancaking issues, PPL urged the Commission to deny the request.[240] PPL emphasized that, unlike the Mountain States project, Commission precedent on granting negotiated rate authority involved cases where either the proposed lines were not interconnected with transmission systems owned by affiliates or an RTO/ISO was to operate and schedule the lines or the proposed projects.[241]

While the Commission reaffirmed its commitment to developing a "new transmission infrastructure that is essential to

235. *See Mountain States,* 127 F.E.R.C. ¶ 61,270 at P 4.

236. *See id.* at P 5.

237. *See id.* at P 6.

238. *See id.*

239. *See id.* at P 12-13.

240. *See id*. at P 14-18. Because it denied the request to charge negotiated rates on the proposed project, the Commission declared the issue of whether Mountain State could grant customers from NorthWestern's queue a tie-breaking priority in Mountain State's open season to be moot. *Id.* at P 65 n.40.

241. *See Mountain States*, 127 F.E.R.C. ¶ 61,270 at P 14 (citing *Neptune*, 96 F.E.R.C. at 61,633; *Sea Breeze*, 112 F.E.R.C. ¶ 61,295, at P 16 (2005); *MATL*, 116 F.E.R.C. ¶ 61,071, at P 14 (2006)).

access and deliver power from locational constrained resources and to meet our Nation's future energy requirements,"[242] the Commission nevertheless denied the request for negotiated rates.[243] Emphasizing the affiliate relationship between Mountain States and NorthWestern, the Commission found petitioners had not shown that negotiated rate authority for the project would be just and reasonable (as required by the FPA) per the first prong of *Chinook* analysis.[244] The Commission explained that its just and reasonable evaluation "first looks to whether the merchant transmission owner has assumed the full market risk for the cost of constructing a particular transmission project and is not building within the footprint of its own (or an affiliate's) traditionally regulated system."[245] Comparing Chinook with Mountain States, the Commission noted that the merchant transmission developers in *Chinook* were new entrants with no affiliates in the footprints of their respective transmission projects. In contrast, the Mountain States project would be largely located within its affiliate NorthWestern's traditionally regulated transmission system.[246] The Commission further noted that NorthWestern had played a "substantial" role in the preliminary developmental stages of the project, undermining the assertion that Mountain States had assumed full risk of the project and giving Mountain States the appearance of an undue preference.[247] In addition, the Commission found that the absence of meaningful competition between affiliates NorthWestern and Mountain States would concentrate their control over transmission in and around Montana, potentially increasing the incumbent utility's market power.[248]

Furthermore, whereas in prior cases the Commission had found that a neighboring transmission system's obligation to expand functioned essentially as a cap on negotiated rates, buttressing the determination that negotiated rates are just and

242. *See id.* at P 58.
243. *See id*.
244. *See id.* at P 57 n.24 (citing *Chinook*, 126 F.E.R.C. ¶ 61,134 (2009)).
245. *Id.* at P 60 n.29 (citing *Chinook*, 126 F.E.R.C. ¶ 61,134 at P 33-37).
246. *See id.* at P 60.
247. *See Mountain States*, 127 F.E.R.C. ¶ 61,270 at P 61.
248. *See id.* at P 62.

reasonable,[249] the Commission concluded that this disciplining force was lacking in *Mountain States*.[250] Granting Mountain States' negotiated rate authority would actually create a disincentive for NorthWestern's to expand its system at cost-based rates under its OATT, the Commission explained.[251] This is because NorthWestern would have incentive to favor its affiliate Mountain States by withholding capacity and/or delaying the timely expansion of its system in response to transmission service requests.[252] Indeed, the fact that PPL's request for transmission service back in 2004 had not yet led to the construction of transmission capacity lent credence to the Commission's rationale, and also discredited the value of NorthWestern's pledge to honor its OATT obligation to expand.[253] The Commission found that the lack of an independent operator, such as an RTO/ISO, in the vicinity of the project exacerbated concerns about the affiliate relationship. Consequently, while, for example, the Commission had allowed the merchant transmission provider NUSCO to charge negotiated rates, even though it would interconnect to an affiliate with captive customers, this was because, contrary to *Mountain States*, NUSCO would turn control of the facilities over to an ISO that would ensure the merchant did not act unduly discriminatorily or erect barriers to entry.[254]

Another example where the Commission recently reached its limits of flexibility is *Sunzia Transmission LLC.*[255] In *Sunzia,* the Commission denied without prejudice authority to charge negotiated rates where the applicant failed three of the four prongs of the four-prong test, proposed presubscription of up to one hundred percent of capacity, possibly allocating some to affiliates, and refused to offer the same presubscription deal to other customers in the open season.

249. *See, e.g.*, *TransÉnergie I*, 91 F.E.R.C. ¶ 61,230, 61,839 (2000).
250. *See Mountain States*, 127 F.E.R.C. ¶ 61,270 at P 63.
251. *See id.*
252. *See id.*
253. *See id.*
254. *See id.* at P 64 n.39 (citing *NUSCO II*, 98 F.E.R.C. ¶ 61,310 (2002)).
255. *See generally Sunzia*, 131 F.E.R.C. ¶ 61,162 (2010).

IV. SUMMARY AND RUMINATIONS

As this survey of Commission precedent reveals, the Commission has borrowed concepts from its market-based rate program[256] and natural gas regulation to devise a creative and flexible approach to assessing negotiated rate authority for merchant transmission. The four-factor test announced in *Chinook,* the approach du jour, is not only flexible, but also provides a consistent framework for assessing disparate and wide-ranging merchant transmission proposals. Significantly, the four-factor test incorporates and balances at least three Commission concerns: (1) the FPA's consumer protection mandates; (2) the financing realities faced by merchant transmission developers; and (3) the Commission's requirements that transmission providers afford customers open access to transmission facilities. In applying the test, the Commission has clearly "demonstrated a commitment to fostering the development of merchant transmission projects where reasonable and meaningful protections are in place to preserve open access principles and to ensure that the resulting transmission rates are just and reasonable."[257]

With regard to consumer protection, the rationale behind negotiated rates for merchant transmission essentially parallels the justification for negotiated rates in the natural gas context. Natural gas pipelines are allowed to charge negotiated rates for transporting natural gas because the customer has the option of requesting the pipeline to provide service under its cost-based recourse rate, which essentially caps the rate for transporting natural gas.[258] Where negotiated rate authority for merchant transmission is concerned, at least theoretically, the generator customer has the option of requesting transmission service, and

256. Note that it is the broad concepts, such as evaluating market power and ongoing oversight, rather than the particular tests, which the Commission has imported into the merchant transmission context. *See Tres Amigas III*, 132 F.E.R.C. ¶ 61,233, at P 31, 68 (2010) (dismissing objection that FERC had not applied the rigorous market power tests used to evaluate generator requests for market-based rate authority to assess the merchant project).

257. *SunZia*, 131 F.E.R.C. ¶ 61,162 at P 38.

258. Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 74 F.E.R.C. ¶ 61,076, 61,236 (1996).

expansion if necessary to provide service, at cost-based rates from its incumbent utility provider.[259] The only ostensible difference between these two regimes is that in the merchant transmission context, the cost-based provider and the merchant transmission provider would be different entities, as opposed to a single natural gas pipeline.[260]

The Commission's approach to merchant transmission reflects an effort to reconcile its traditional obligation under the FPA to protect consumers with the current need to encourage third-party investment in the transmission grid. Consequently, as the above discussion reveals, the Commission has recognized and attempted to accommodate the financing difficulties merchant transmission developers face, by, for example, changing its policy to allow pre-open season contracting for transmission capacity. The Commission has nevertheless imposed several critical requirements on these projects to ensure that, consistent with the FPA, service is provided on a just and reasonable and not unduly discriminatory basis.

These obligations include, first, equal opportunity to obtain service at the outset of the project. If there are anchor customers, the merchant transmission provider must offer the same terms of those agreements to other customers. Also, reflecting natural gas precedent, there must be a non-discriminatory, fair and transparent open season – or at least something comparable to an open season[261] – with sufficient notice, so all customers have the opportunity to obtain service on the merchant line on the same or similar terms. In order to be fair and transparent, the open season processes must be published before the open season begins. This includes publishing rules on who may bid, description of the bidding process, what a bid must include, how bids will be selected and how capacity will be apportioned if there

259. *See TransÉnergie I*, 91 F.E.R.C. ¶ 61,230, 61,838-89 (2000).

260. *See, e.g.*, *MATL*, 116 F.E.R.C. ¶ 61,071, at P 52 (2006) ("In summary, the Commission found in *TransÉnergie* that negotiated rate authority could be granted to a merchant transmission facility interconnected with an RTO given the cap effectively created by the difference in LMP prices on each end of the merchant line and the expansion cost cap.").

261. *See, e.g.*, Conjunction L.L.C., 108 F.E.R.C. ¶ 61,090, ¶ 61,090 (2004) (finding Requests for Proposals ("RFP") that are open to the public and fair in transparent may constitute an acceptable open season).

is a plethora of interest or tie bids. To further enhance transparency, the Commission also requires merchant project developers to disclose their selection rationale in an open season report.[262] It also bears emphasizing that an important purpose of the open season is to judge the extent of market interest in the project, which factors into how to decide the extent of the project, i.e., right sizing.[263] This helps guarantee there is sufficient transmission capacity to meet customers' needs, and also protects the merchant transmission developer's interest in not overbuilding.

Second, terms of service must be standard and transparent. Service must be provided under an OATT, either that of the RTO at or near the vicinity of the project, or, if not, the project must provide the service under its own OATT.[264] This makes merchant transmission providers subject to the open access requirements of Order Nos. 888 and 890, like all transmission providers subject to Commission jurisdiction. This is consistent with natural gas regulation, which also requires pipelines to provide open access transportation service. Pipelines, which are like merchant transmission facilities in that they are stand-alone rather than vertically-integrated, must offer firm and interruptible service under a Commission-approved, generally applicable tariff.

Third, there must be a transparent opportunity for customers subsequently to obtain capacity: the merchant transmission facility must create tradable firm secondary transmission rights,

262. The Commission has demonstrated sensitivity to the complexity of bid evaluation, however, by allowing providers to use non-price considerations that implicate financial risk, such as levels and type of insurance. *See TransEnergie II*, 91 F.E.R.C. ¶ 61,347 at 61,167 n.5 (citing Open Season Report, June 9, 2000, Attach. 1, at 6).

263. *TransEnergie I*, 91 F.E.R.C. ¶ 61,230, 61,839. Indeed, after the open season, some projects were re-sized, such as Neptune's. *See Neptune II*, 102 F.E.R.C. ¶ 61,213, at P 3-5 (2004) (discussing impact of dismal open season on timing of various phases of the project as initially proposed).

264. *See, e.g.*, *Neptune I*, 96 F.E.R.C. ¶ 61,147, 61,633 (2001) (denying Neptune's request for waiver of the requirement to provide service under a Order No. 888 pro forma tariff). *But see* PSEG Energy Res. & Trade, 123 F.E.R.C. ¶ 61,001, at P 28 (2008) (allowing a generation tie line facility to serve its sole generation customer in accordance with its contract and defer open access until receiving a third party request for service on the tie line).

which must be posted on an OASIS. The Commission extolled this as a critical feature of the original merchant transmission proposal, *TransEnergie,* finding that a vibrant secondary market would enhance competition in both the source and sink markets. The Commission also required the developer to specify procedures for customers to reassign rights and to follow the posting requirements in Order No. 889. This is consistent with natural gas regulation, which operates under a physical rights model – firm customers on interstate pipelines are allowed to release their capacity to other shippers via auction or the pipeline's electronic bulletin board or through a bilaterally negotiated transaction, which must be posted on the electronic bulletin board for informational purposes. As for tradable financial rights, posting firm secondary transmission rights is also consistent with the way financial transmission rights are treated in organized markets.

Fourth, consistent with the Commission's market-based rate program and natural gas regulation, the merchant transmission provider must address affiliate concerns to guard against undue preference. As discussed above, the early projects proposed to appease affiliate concerns by not allowing affiliates to participate in the open season. Subsequent projects proposed measures to prevent affiliate abuse if affiliates were included in their open season, such as hiring an independent consultant or auditor to evaluate sealed bids at the end of the open season period.[265]

Having said this, and because the Commission's approach to merchant transmission has so recently evolved and is largely untested in the courts, there remain certain challenges that may bear further consideration. First, there is an inherent tension between the Commission's open access policy and the use of anchor shippers. How much capacity is it just and reasonable to allocate prior to an open season? While the Commission has permitted as high as seventy five percent of capacity to be pre-subscribed,[266] the outcome of that case may have been influenced

265. *See, e.g.*, *Conjunction L.L.C.*, 108 F.E.R.C. ¶ 61,090 at P 13; *Sea Breeze*, 112 F.E.R.C. ¶ 61,295, at P 29 (2005); *MATL*, 116 F.E.R.C. ¶ 61,071 at P 35, 41; Linden VFT, L.L.C., 119 F.E.R.C. ¶ 61,066, at P 25, *order on clarification,* 120 F.E.R.C. ¶ 61,242 (2007).

266. *See Champlain*, 132 F.E.R.C. ¶ 61,006, at P 47 (2010).

by the applicant's insistence that such a high percentage was necessary to obtain ARRA financing. Because certainty enhances efficiency, however, the Commission may want to consider explicitly establishing a limit, even if it is a "soft cap" that leaves open the possibility that extraordinary circumstances (or some other standard) could warrant a higher percentage in particular cases.

Additionally, it seems probable that the Commission will be asked at some juncture whether the existing approach provides sufficient protection against the exercise of monopoly power. When initially approving a merchant transmission developer's negotiated rate application, arguably the Commission need not be overly concerned with market power issues. This is because, as the Commission has held, market power is initially checked by the incumbent utilities' ability to expand to provide new service, and, at least theoretically, other merchant transmission providers and their investors may step up to fund competing projects.[267] Once the merchant transmission project is built, however, market power issues may become more acute. Although conceivably its customers could seek other transmission alternatives, such as requesting the incumbent public utility to build a new competing line, or purchase generation elsewhere, in practice this might not prove to be a viable alternative.[268] For example, a new line could be cost prohibitive or the new line could not be built in sufficient time to serve the customer's needs or the customer could be obligated to purchase energy from a renewable resource to meet its RPS requirement, but competing generation from these sources is not available except as provided by the merchant transmission line. Where a line traverses more than one state, as in Chinook/Zephyr, it becomes more difficult to build an alternative to the original line because the customer would likely have to negotiate with more than one public utility/transmission provider and face more regulatory hurdles.

267. Interview with David Mead, Economist, FERC (Jan. 13, 2011) (on file with author).

268. *Cf. Mountain States,* 127 F.E.R.C. ¶ 61,270, at P 12 (2009) (noting that customer requested interconnection with incumbent utility and waited in the queue for over 5 years).

At least two potential solutions to this dilemma are ongoing monitoring, akin to what the Commission employs in its market-based rate program, and an "open tap" policy, which would require the transmission provider to allow expansion of the line to serve a new customer.[269] The Commission already has the basic tools for monitoring in place, including requiring transparent secondary trading on the transmission provider's OASIS and a division devoted to market oversight and enforcement. Furthermore, akin to pipelines, merchant transmission providers file open season reports and, as in the market-based rate program, merchant transmission providers also file electronic quarterly reports detailing their transactions.[270] As for an open tap policy, it may be appropriate to require the merchant transmission provider to permit expansion of the original merchant transmission facilities if needed to serve a new customer.[271] This would further the Commission's open access goals.

In addition, because the merchant transmission provider is linking two pricing regions, it is enhancing competition, and helping the prices converge between the two regions. The transmission provider's negotiated rate, however, is based on the spread between the two regions. Accordingly, the transmission provider has an incentive to keep the price differentials between the two regions high.[272] This tendency can be tempered, however, through ongoing monitoring.[273]

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269. Interview with David Mead, *supra* note 267.

270. *See, e.g.*, *Chinook*, 126 F.E.R.C. ¶ 61,134, at P 9 (2009).

271. Some applicants have offered to expand, if feasible, and the Commission has accepted this representation. *See MATL*, 116 F.E.R.C. ¶ 61,071, at P 24 (2006); *see also Tres Amigas III*, 132 FERC ¶ 61,233, at P 41 (2010) (finding Tres Amigas' offer to expand its facility at cost-based rates if the needed expansion is not supported by negotiated rates provides customers with one of a number of cost-based alternatives).

272. Interview with Partha Malvadkar, Economist, FERC (Mar. 15, 2011) (on file with author).

273. Note that the Commission has an active office of Market Oversight and Enforcement. Also, to aid transparency and facilitate liquidity, the Commission already requires secondary trading on OASIS. *See, e.g.*, *Tres Amigas I*, 130 F.E.R.C. § 61,207, at P 80 (2010) (accepting applicant's commitment to establish an OASIS to enable the trading of secondary transmission rights); *Chinook,* 126 F.E.R.C. at P 51, 54 (requiring all purchases of transmission rights on a merchant transmission line after the open season to be conducted transparently

Finally, there is a separate line of cases, involving "gen-tie" lines, which, while distinct from the merchant transmission context, have raised related open access, undue discrimination, and potential market power issues.[274] Whereas a merchant transmission line is built to serve third parties, a gen-tie is a line built and owned by the generator to connect its generation resources to the transmission grid. It serves itself, essentially.[275] Because the generator builds the line to serve its own needs, and not those of third parties, the Commission has permitted the generator to dedicate one hundred percent of the gen-tie's capacity to its own needs, as long as the generator can demonstrate that it actually needs or has specific pre-existing plans to develop generation that will utilize all of this capacity to transmit its generation to the grid.[276] If a generation developer constructs a gen-tie with capacity greater than its immediate needs, in anticipation of expanding its own generation in the future, and a third party wants access, then the generator must make the capacity available to the third party until it needs the capacity to serve its own generation.[277] Again, because merchant transmission is built to serve third parties, this differs from the way that merchant transmission is handled. As we have seen, at least to date, the Commission has not allowed all capacity on a

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and posted on the relevant transmission owner's OASIS; both Chinook and Zephyr committed to establishing a website and ultimately an OASIS to enable the trading of secondary transmission rights).

274. *See, e.g.*, Ne. Utils. Serv. Co., 127 F.E.R.C. ¶ 61,179, at P 17 (2009); Milford Wind Power Corridor, L.L.C. (*Milford*), 129 F.E.R.C. ¶ 61,149, at P 23-24 (2009); Aero Energy, L.L.C., 115 F.E.R.C. ¶ 61,128, at P 39 (2006).

275. Under the traditional model, a generator would request the transmission provider to interconnect the generator with its facilities, and the transmission provider, according to its OATT, would construct the facilities needed to connect the renewable generation source to the grid. *See generally* Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003); Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007). However, the transmission provider may not be able to construct the interconnection in time to meet the developer's needs, or it may be too expensive, or the generator may prefer to own the line itself, so developers are opting to construct the interconnection themselves.

276. *See* Terra-Gen Dixie Valley, L.L.C., 132 F.E.R.C. ¶ 61,215, at P 50 n.90 (2010) (citing *SunZia*, 131 F.E.R.C. ¶ 61,162, at P 37 (2010); Aero Energy L.L.C., 116 F.E.R.C. ¶ 61,149 at P 28).

277. *See Milford*, 129 F.E.R.C. ¶ 61,149 at P 23.

merchant line to be pre-subscribed in anchor customer agreements, and is wrestling with the issue of how much capacity must be made available in an open season; furthermore, the Commission also requires tradable rights on the secondary market for merchant transmission capacity.

A salient difference between these two scenarios, however, is that since the gen-tie line is built to serve the generator's own needs, and not third parties, there is no open season requirement or presubscription phase that might help right-size the line at the outset. This matters because as generators build ever longer gen-tie lines, they come to resemble, superficially at least, merchant transmission facilities linking renewable generation resources to the grid or other markets. If the gen-tie line is the only line in a certain region, it may raise market power concerns, particularly barriers to entry. This body of precedent, like the merchant transmission precedent, is complex and rapidly evolving. The Commission may want to consider harmonizing these two bodies of precedent and framework of analyses.[278]

V. CONCLUSION

Drawing on concepts from its market-based rate program and natural gas regulation, as well as economic principles, the Commission has found innovative ways to support merchant transmission solutions. In granting applications for negotiated rates, the Commission has recognized the financial needs of

278. Notably, on March 15, 2011, Commission staff held a technical conference to explore issues related to merchant transmission and gen-tie lines. In a two-panel format, participants expressed their views concerning the appropriate balance between open access, undue discrimination, transmission project financing and efficient, low-cost interconnection of renewable generation. The merchant (and/or independent) transmission panel focused on the tension between allocation of priority rights for use of transmission facilities and open access policies. Among other things, panelists discussed "right-sizing" projects, open seasons, and the need for flexibility in anchor shipper arrangements. The gen-tie line panel discussed the application of the Commission's open access policies to gen-tie lines when third-parties seek to use their facilities. *See* Supplemental Notice of Technical Conference re Priority Rights to New Participant Funded Transmission, Docket No. AD11-11-000 (Mar. 7, 2011). The technical conference was webcast, and staff announced at the technical conference that a supplemental notice will provide the deadline and details for filing post-technical conference comments with the Commission.

merchants, while honoring the Commission's statutory obligation to ensure that rates, terms and conditions of transmission service are just and reasonable and not unduly discriminatory. The Commission has demonstrated flexibility in its analysis, and will no doubt continue to refine its approach, as the landscape for transmission and generation, particularly renewable resources, continues to change.[279]

279. For an engaging and provocative discussion of the future of the American electricity industry, including the transmission grid, see generally Fox-Penner, *supra* note 4. As the author opines, "the economic and regulatory structure of the American power industry is a contraption only a lawyer could love." *Id.* at 10.