ELECTRIC WHOLESALE POWER SALES AT MARKET-BASED RATES

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I. INTRODUCTION

The use of market-based pricing for wholesale sales of electric power with the corresponding reliance on competition in the marketplace is timely as the nation seeks to augment and diversify its electric generating resources. Increasing competitive pressures in the marketplace have fostered development of non-utility electric generating facilities to meet supply needs, including those developed and constructed as qualifying facilities (QFs) in connection with section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA),[1] independent power producers (IPPs), and power producers which are affiliated with public utilities or entities that have franchised service areas. Questions of competition and market-based pricing are also relevant (insofar as "traditional" utilities are concerned) as a possible method to encourage more efficient and productive utilization of existing generation resources.

This enhanced competitive environment has led the Federal Energy Regulatory Commission (FERC or Commission) to recognize that the long-standing and traditional approach to ratemaking by using an entity's costs may not be appropriate in all situations. Thus, the Commission has expressed dissatisfaction with the potential for discouraging economic incentives for investment under cost-based pricing,[2] indicated concern with the potentially subjective nature of traditional ratemaking methodologies,[3] and has noted the increasing amount of wholesale electricity that has been purchased within the industry in place of higher-cost self-generated electricity.[4] The growing influence of market-based pricing is evidenced by the increasing number of proposals that have come before the Commission for the sale of power where market-based pricing considerations are reflected and by the Commission's efforts to examine significant issues facing the electric industry, including questions that directly concern market-based rates and their relationship with access to transmission services.[5]

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1. 16 U.S.C. §§ 824a-3 (1988).

2. *See* Notice of Proposed Rulemaking, *Regulations Governing Indep. Power Producers*, IV F.E.R.C. Stats. & Regs. ¶ 32,456, at 32,108, 53 Fed. Reg. 9327 (1988).

3. *See* Ocean State Power, 44 F.E.R.C. ¶ 61,261, at 61,983 (1988).

4. Commonwealth Atl. Ltd. Partnership, 51 F.E.R.C. ¶ 61,368, at 62,248 (1990).

5. *See* Notice of Public Conference and Request for Comments on Electricity Issues, 55 F.E.R.C. ¶ 61,069 (1991) [hereinafter Notice of Public Conference]. The Commission has recently accepted market-based rates without a substantive discussion of market power and other issues addressed in previous orders on electric market-based pricing proposals. *See* Wallkill Generating Co., L.P. 56 F.E.R.C. ¶ 61,067 (1991) (letter order).

For example, in its recent public conference on electricity issues, the Commission addressed certain matters relating to changes in the electric industry, including the role of independent and affiliated power producers. The Commission specifically sought to address whether: (1) market-based rates for wholesale power sales should be examined on a case-by-case or generic basis, (2) the Commission's deliberations of market-based rates have been consistent, (3) greater regulatory certainty can be provided for parties that propose to utilize market-based rates, and (4) the Commission has adequately examined and considered issues relating to affiliations involving power producers or marketers.[6] As a part of the conference proceedings, Commissioner Trabandt suggested, and requested comments upon, a procedure providing for automatic Commission approval of market-based, non-contested rates for IPPs and public utilities.[7] Such a procedure would apply where there is no affiliation between the seller and the purchaser (and any utility interconnected with the purchaser), where the seller does not own or control transmission that reaches the buyer, and where the capacity being offered is new capacity.[8] This proposed abbreviated review would also apply when all of the following factors are met: (1) there is no affiliation between the parties, (2) all power would flow within a state, (3) utilities are required under a state procurement plan to obtain power by the most economical means, and (4) and the state has approved the purchase under the procurement plan.[9]

In cases where the Commission has approved market-based pricing for wholesale electric sales, it reasoned that substantial changes occurring in the electric industry require consideration of when such pricing may satisfy the just and reasonable standard under the Federal Power Act (FPA).[10] In these instances, the Commission sought to inquire whether non-traditional rate proposals meet the goal of "ensuring an adequate and reliable supply of electricity at the lowest possible cost to consumers in the long run."[11] The Commission also examined whether the pricing method will allow the most cost-efficient resources to be used and if incentives for productivity-enhancing innovation will result from competitive pressures on suppliers.[12] Market-based pricing proposals have received Commission approval where concerns with market power and excessive rates are alleviated:

> The Commission has allowed pricing flexibility in recent cases, and has concluded that noncost based rates fall within a zone of reasonableness in circumstances where the seller can show that it lacks market power or has mitigated its

6. Notice of Public Conference, *supra* note 5, at 61,196. In its Notice, the Commission also addressed issues relating to integrated resource planning, transmission access, electric utility mergers, and the Commission's role in implementing the Clean Air Act Amendments of 1990. *Id.* at 61,196-97.

7. Public Conference and Request for Comments on Electricity Issues, No. PL91-1-000, slip op. at 1-3 (June 28, 1991) (Questions from Comm'r Trabandt).

8. *Id.* at 2.

9. *Id.* at 3.

10. Federal Power Act, 16 U.S.C. §§ 791-825 (1988). *See, e.g.*, Opinion No. 349, Pub. Serv. Co. of Ind., 51 F.E.R.C. ¶ 61,367, at 62,223, *order on reh'g*, Opinion No. 349-A, 52 F.E.R.C. ¶ 61,260, *clarified and modified*, 53 F.E.R.C. ¶ 61,131 (1990), *appeal pending sub nom.*, Northern Indiana Pub. Serv. Co. v. FERC, No. 90-1528 (D.C. Cir. Nov. 9, 1990).

11. Enron Power Enter. Corp., 52 F.E.R.C. ¶ 61,193, at 61,711 (1990).

12. *Id.*

> market power, and there is a pricing cap based either on the seller's costs, or on the purchaser's avoided cost.[13]

Even where market-based pricing is approved, fundamental statutory requirements must still be met. In *Farmers Union Central Exchange v. FERC (Farmers Union)*,[14] the United States Court of Appeals for the District of Columbia Circuit makes clear that the Commission cannot rely solely on market forces as the means of rate regulation. The Commission must determine whether the rates fall within the zone of reasonableness, analyze the existence of a competitive market, discuss any relevant non-cost factors, and establish a method to monitor that the market-based rates remain within the zone of reasonableness.[15]

Questions relating to market-based pricing have also been considered in developments on others fronts. Potential Congressional reform of the Public Utility Holding Company Act of 1935 (PUHCA),[16] for the purpose of exempting certain wholesale power generators from the PUHCA, may encourage the development of new wholesale power generators. However, such potential exempt status under PUHCA may not necessarily remove those generators from the Commission's rate regulation under the Federal Power Act (FPA), including any related examination of market power and affiliated dealings.[17] Moreover, the potential for Congressional imposition of least cost planning requirements upon utilities may impact on the Commission's determination of whether a market-based rate for a wholesale power purchase is just and reasonable. Depending upon the extent of statutory change, a utility's wholesale purchase of power at a rate consistent with a least cost planning mandate may aid the Commission in approving the transaction.

Market-based pricing has been present in certain recent proceedings under the Natural Gas Act (NGA),[18] where the Commission has considered issues of competition analogous to those in electric market-based ratemaking proceedings.[19] For example, in order to depart from cost-of-service ratemaking principles in favor of flexible pricing contained in a gas pipeline's gas inventory charge,[20] the Commission has indicated that it must: (1) find that market-based pricing would promote the statutory objectives of the NGA; (2) conclude, based on substantial evidence, that competition in the relevant

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13. Doswell Ltd. Partnership, 50 F.E.R.C. ¶ 61,251, at 61,756 (1990) (footnotes omitted).

14. Farmers Union Cent. Exch., Inc. v. FERC, 734 F.2d 1486 (D.C. Cir.), *cert. denied*, 469 U.S. 1034 (1984).

15. *Id.* at 1507-10.

16. 15 U.S.C. §§ 79-79z-6 (1988).

17. *See* Cynthia A. Marlette, Associate General Counsel, Federal Energy Regulatory Commission, Statement before the Subcommittee on Energy and Power, United States House of Representatives (May 1, 1991) at 2-3.

18. 15 U.S.C. §§ 717-717z (1988).

19. *See, e.g.*, Transcontinental Gas Pipe Line Corp., 55 F.E.R.C. ¶ 61,446, at 62,332-35, *order amending settlement*, 56 F.E.R.C. ¶ 61,085 (1991); Transwestern Pipeline Co., 43 F.E.R.C. ¶ 61,240, at 61,650-53, *reh'g granted in part*, 44 F.E.R.C. ¶ 61,164 (1988), *remanded on other grounds*, 897 F.2d 570 (D.C. Cir. 1990); Transwestern Pipeline Co., 53 F.E.R.C. ¶ 61,298, at 62,113-15 (1990).

20. A gas inventory charge is a mechanism to "define the limits on pipelines' ability to charge their customers for the costs of maintaining an inventory of contract rights to purchase gas. . . ." *Transwestern*, 897 F.2d 570, at 573.

markets would operate as a "meaningful constraint" on the pipeline's exercise of market power; and (3) establish that the market-based pricing mechanism, with a cost-based cap or constraint, would produce a rate within a zone of reasonableness.[21] In its notice of proposed rulemaking concerning the restructuring of gas pipeline services, the Commission has indicated that the competitive marketplace, and not regulation, should be the "primary incentive" for willing buyers and sellers to enter into transactions, and that market-based sales pricing or gas inventory mechanisms are appropriate for firm sales that are unbundled from any transportation service.[22] There, the Commission noted that a pipeline's sales are considered to be made in a sufficiently competitive market when the pipeline provides comparable transportation service with respect to all gas supplies, and when there is adequate divertable gas. In addition, the Commission suggested the establishment of a market-based pricing mechanism because, first, it proposed to establish comparable transportation services for all gas supplies whether purchased from the pipeline or another source; and second, adequate divertable gas supplies were found to exist because of the determination that the market for natural gas is competitive on a national level as a result of the Congress' decontrol of all first sales of gas supplies.[23] The Commission's actions regarding the natural gas industry, particularly with respect to the use of market-based rates and the implementation of open-access transportation, may well provide significant guidance to the future of market-based ratemaking in the electric industry and transmission access as a means to mitigate market power.

This article examines the various considerations given by the Commission under recent proposals for the use of market-based pricing for the wholesale sale of electric power. Reviewed are Commission decisions which approve or reject such proposals as just and reasonable through analysis of issues pertaining to: (1) market power, (2) self-dealing and abuse stemming from affiliate relationships, and (3) the use of price caps or ceilings or other constraints to keep market-based rates within the statutory zone of reasonableness.

II. JUDICIAL DECISIONS USED TO JUSTIFY MARKET-BASED RATEMAKING

A departure from cost-based pricing and use of other ratemaking methodologies such as market-based pricing still requires that the just and reasonable standard of the FPA be satisfied.[24] Section 205(a) of the FPA provides

21. *Transwestern*, 43 F.E.R.C. ¶ 61,240, at 61,650. *See also Transcontinental*, 55 F.E.R.C. ¶ 61,446, at 62,334. Where the pipeline's customers had access to substantial sales and transportation capacity on a number of other pipeline systems, the Commission was able to determine that a sufficiently competitive market existed. In concluding that non-cost based pricing was acceptable, the Commission also found a lack of significant market power by the subject pipeline in the supply area where it purchased gas. *Transwestern*, 43 F.E.R.C. ¶ 61,240, at 61,651-52.

22. *In re* Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, 56 F.E.R.C. ¶ 61,178 slip op. at 33 (1991).

23. *Id.* at 32-33. The Commission also determined that the issue of sufficient divertible gas supplies need not be considered because of the significant amount of uncommitted gas available at competitive prices. *Id.* at 33.

24. The Commission appears to have gone to great length in proceedings under the NGA to

that all rates for the transmission or sale of electric energy subject to the Commission's jurisdiction be just and reasonable, and that any such rate which is not just and reasonable is unlawful.[25] At any hearing involving a proposed rate increase, the burden of proof is on the filing public utility to demonstrate that its increased rate is just and reasonable.[26] Section 206 of the FPA permits the Commission, after hearing, to establish the just and reasonable rate to be thereafter in force.[27]

Although *Federal Power Commission v. Hope Natural Gas Co. (Hope)*[28] indicates that the use of historical costs is a valid (but not the only) general methodology on which to calculate utility rates, it also holds that the Commission is not bound to any single formula or theory in ratemaking, but instead must assure that the "total effect" of its rate determination is not unjust and unreasonable.[29] Moreover, the Commission is authorized to make, where necessary, pragmatic adjustments in its ratemaking role.[30] Rates established as just and reasonable are tested to determine whether they fall within a "zone of reasonableness." At one end of the zone the need to "maintain financial integrity, attract necessary capital, and fairly compensate investors" is recognized, while the other end exists to "provide appropriate protection to the relevant public interests, both existing and foreseeable."[31] The Commission enjoys discretion in carrying out its ratemaking functions, yet it must still act within the "just and reasonable" statutory standard.[32] Further, it cannot establish ratemaking policy on mere economic theory alone, but must do so on the basis of record evidence and reasoned decisionmaking.[33] The Commission, in recent issuances, has justified its use of market-based or non-cost ratemaking considerations by reliance on *Hope* and other cases that fall primarily under

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distinguish between market-based rates and potential deregulation. In its notice of proposed rulemaking for gas pipeline service obligations the Commission stated that it was "not proposing the deregulation of pipeline sales." *In re* Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, 56 F.E.R.C. ¶ 61,178 slip op. at 33 (1991). Instead, the Commission stated that its reliance on decontrolled market forces to constrain certain gas prices within the NGA's just and reasonable standard amounts to "light-handed regulation." *Id. See also Transcontinental*, 55 F.E.R.C. ¶ 61,446, at 62,332-33 (reliance placed on competitive market forces to constrain gas prices within a just and reasonable range).

25. 16 U.S.C. § 824d(a) (1988).

26. *Id.* § 824d(e) (1988).

27. *Id.* § 824e(a) (1988).

28. 320 U.S. 591 (1944).

29. *Id.* at 602. *See also* Alabama Elec. Coop., Inc. v. FERC, 684 F.2d 20, 27 (D.C. Cir. 1982) (footnote omitted), which states:

> While neither statutes nor decisions of this court require that the Commission utilize a particular formula or a combination of formulae to determine whether rates are just and reasonable, it has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity.

30. *Hope*, 320 U.S. at 602. (citing FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942)). *See also* Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989).

31. Permian Basin Area Rate Cases, 390 U.S. 747, 792 (1968). *See also* Jersey Cent. Power & Light Co. v. FERC, 810 F.2d 1168, 1176 (D.C. Cir. 1987).

32. FPC v. Texaco, Inc., 417 U.S. 380, 394 (1974).

33. Electricity Consumers Resource Council v. FERC, 747 F.2d 1511, 1517 (D.C. Cir. 1984).

the Commission's natural gas ratemaking duties[34] and on meeting certain principles set forth in *Farmers Union*.

These authorities recognize the Commission's ability to use a ratemaking methodology which relies on market forces instead of one based strictly on costs, but they do not relieve the Commission of its duty to meet the just and reasonable requirement. For example, in *City of Detroit v. FPC*,[35] orders were remanded for the Commission to supplement the record and justify its use of a field price for a utility's own produced gas in calculating rates in place of a price based on the "traditional rate base method." The Court indicated that the Commission would not be precluded from substituting the field price method, provided that the just and reasonable rate level was not exceeded and that the use of the field price method was justified in terms of a demonstrated public interest.[36] Moreover, a comparison with the results of the "traditional" methodology was necessary as a point of departure:

> [W]hen we refer to an "increase" we mean an increase in the rates above those which would result from use of the conventional rate-base method. For, though we hold that method not to be the only one available under the statute, it is essential in such a case as this . . . has been repeatedly used by the Commission, and repeatedly approved by the courts, as a means of arriving at lawful—"just and reasonable"—rates under the Act. Unless it is continued to be used at least as a point of departure, the whole experience under the Act is discarded and no anchor, as it were, is available by which to hold the terms "just and reasonable" to some recognizable meaning.[37]

Derivations from cost-based pricing must not be unreasonable and must be consistent with the Commission's other responsibilities.[38] In *FPC v. Texaco, Inc.*,[39] the Court remanded to the Commission an order which exempted small natural gas producers from direct rate regulation on the grounds that rates could be regulated through the review of the cost of purchased gas for purchasing pipelines. The Court stated that although the law directs that producer rates be "just and reasonable," this does not mean that the "cost of each

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34. *See, e.g.*, Opinion No. 349, *infra* note 77, 51 F.E.R.C. ¶ 61,367, at 62,222. The relevant portions of the Natural Gas Act (NGA) and the Federal Power Act (FPA) are in all material respects substantially identical, and may be cited interchangeably. *See, e.g.*, Arkansas Louisiana Gas Co. v. Hall, 453 U.S. 571, 577 n.7 (1981).

35. City of Detroit v. FPC, 230 F.2d 810 (D.C. Cir. 1955), *cert. denied*, 352 U.S. 829 (1956).

36. *Id.* at 815, 818. The Court also stated that if the purpose of the rate increase is to encourage development, then the Commission must be satisfied that the increase is no more than is actually needed. *Id.* at 817.

37. *Id.* at 818-19. The use of non-cost based pricing also has been the subject of other proceedings under the NGA, including those relating to area rate proceedings. For example, in Wisconsin v. FPC, 373 U.S. 294, 309 (1963), the Supreme Court stated that individual company cost of service ratemaking was not an indispensable methodology. Also, the Commission's reliance on both cost and non-cost factors in setting area rates for natural gas was found acceptable in Permian Basin Area Rate Cases, 390 U.S. at 815, where the Supreme Court held that consumer interests could not properly be served by excluding all but current or projected costs.

38. *See, e.g.*, Mobil Oil Corp. v. FPC, 417 U.S. 283, 308-09 (1974) (quoting *Permian Basin*, 390 U.S. at 792). *See also* FERC v. Pennzoil Producing Co., 439 U.S. 508, 518 (1979) (quoting *Mobil*, 417 U.S. at 308-09); Farmers Union Cent. Exch. Inc. v. FERC, 734 F.2d at 1502 (D.C. Cir. 1984).

39. Texaco, Inc. v. FPC, 474 F.2d 416 (D.C. Cir. 1972), *approved in relevant part and vacated on other grounds*, 417 U.S. 380 (1974).

company be ascertained and its rates fixed with respect to its own costs."[40] However, the Court also makes clear that Congressional intent for the NGA did not include having price always dictated by the marketplace:

> For the purposes of the proceedings that may occur on remand, we should also stress that in our view the prevailing price in the marketplace cannot be the final measure of "just and reasonable" rates mandated by the Act. . . . This does not mean that the market price of gas would never, in an individual case, coincide with just and reasonable rates or not be a relevant consideration in the setting of area rates, it may certainly be taken into account along with other factors. It does require, however, the conclusion that Congress rejected the identity between the "true" and the "actual" market price.[41]

Recent Commission orders seek to satisfy *Farmers Union*. There the Court remanded a Commission order concerning a generic ratemaking methodology for oil pipelines under the Interstate Commerce Act. The Commission determined that competitive market forces should be relied upon in setting rates and found that rate regulation of oil pipelines should protect against "egregious exploitation and gross abuse" by the regulated pipelines.[42] Moreover, the Commission found that ratemaking should be used to keep rates in a "zone of commercial reasonableness," but not necessarily a "public utility [zone of] reasonableness."[43]

Under review, the Court found that the Commission's "novel" interpretation of its ratemaking duties failed to square with the just and reasonable standard and faulted the Commission for seeking to set rates at a level in excess of the statutory zone of reasonableness.[44] Although numerous factors could be used to determine the bounds of the zone of reasonableness, an inquiry into cost was cited as the "most useful and reliable starting point."[45] In order to rely on non-cost factors in setting rates, the Commission must act consistently with its statutory responsibility and "specify the nature of the relevant non-cost factor and offer a reasoned explanation of how the factor justifies the resulting rates."[46] The Court found that the Commission had not acted within its statutory duties of assuring that rates be just and reasonable. To the contrary, by setting rates which guarded "against only grossly exploitative pricing practices" the Commission "abdicated its statutory responsibilities."[47] The Court held that "contrasting or changing characteristics of regulated industries" may justify changes in the process used to determine just and reasonable rates, but the Commission could not "pour any meaning" it wanted into the statute.[48] Furthermore, the Commission's reliance on market forces as a leading method of rate regulation was held to be misplaced. Market price,

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40. *Id.* at 387.

41. *Id.* at 397-99 (footnote and citations omitted).

42. Opinion No. 154, Williams Pipe Line Co., 21 F.E.R.C. ¶ 61,260, at 61,649 (1982).

43. *See* Farmers Union Cent. Exch. Inc., 734 F.2d at 1492.

44. *Id.* at 1501.

45. *Id.* at 1502 (citing Mobil Oil Corp. v. FERC, 417 U.S. at 305-06, 316; FPC v. Hope Natural Gas Co., 320 U.S. at 602-03).

46. *Farmers Union*, 734 F.2d at 1502.

47. *Id.* at 1503-04.

48. *Id.*

together with other factors, may be relevant in a particular case.[49] However, the Commission's approval of rates above the zone of reasonableness went beyond any rational consideration of market power because it relied only on competitive forces to keep rates in check and was thus rendered unlawful by its failure to establish a device to monitor rates if competition does *not* drive the price within the zone of reasonableness.[50]

Another important aspect of market-based rates is the issue of undue preferences resulting from affiliate dealings. Section 205(b) of the FPA provides that "no public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, make or grant any undue preference or advantage, or maintain any unreasonable difference in rates, charges or services."[51] Discrimination is prohibited in order to prevent favored rate treatment where services are substantially similar.[52] Affiliate relationships are analyzed out of concern that incentives to provide a preferential or more favorable rate to an affiliate could result in an exercise of market power and thus distort the market and impair the establishment of just and reasonable rates.

III. DETERMINATION OF MARKET POWER

Market-based pricing may be appropriate to establish just and reasonable rates when a working competitive market exists or where the seller or its affiliate does not possess significant market power.[53] The lack of market power has been critical to the approval of market-based pricing.[54] A seller has market power when it "can significantly influence the price in the market by withholding service and excluding competitors for a significant period of time."[55] Market power also may be present where a seller "can hold a price constant and offer an inferior service while excluding competitors."[56] The use of market power has been said to cause unreasonably high rates and inefficient decisions by consumers and those generating power.[57]

In case-by-case determinations of market-based pricing proposals, the Commission has analyzed market power and, where necessary, any affiliation between the seller and an entity, including franchised utilities, that could lead to favored or preferential treatment or discourage competitors from offering service, or otherwise have the effect of distorting the marketplace and thus affecting market power. In these instances, the Commission has required that the seller bear its burden to demonstrate a lack of market power by showing:

49. *Id.* at 1509 (citing Texaco Inc. v. FPC, 417 U.S. at 399 (1974)).

50. *Id.* (citing Texaco, Inc. v. FPC, 474 F.2d 416, 422) (D.C. Cir. 1972) (emphasis added).

51. 16 U.S.C. § 824d(b) (1988).

52. *See* St. Michaels Utils. Comm'n v. FPC, 377 F.2d 912, 915 (4th Cir. 1967).

53. Ocean State Power, 44 F.E.R.C. ¶ 61,261, at 61,979 (1988) (citations omitted).

54. *See* Doswell Ltd. Partnership, 50 F.E.R.C. ¶ 61,251, at 61,756 (1990).

55. *Id.* at 61,757 n.12 (1990) (citing Citizens Power & Light Corp., 48 F.E.R.C. ¶ 61,210, at 61,777) (1989).

56. Terra Comfort Corp., 52 F.E.R.C. ¶ 61,241, at 61,837 (1990) (footnote omitted).

57. Ocean State Power, 44 F.E.R.C. ¶ 61,261, at 61,981 (1988).

1. The seller and its affiliates are not a dominant firm in the sale of generation services in that market;
2. The seller and its affiliates do not own or control any electric transmission facilities that the buyer could utilize to reach alternate suppliers of generation services, or that the seller and its affiliates have adequately mitigated their ability to deny the buyer access to those alternate suppliers; and
3. The seller and its affiliates are not able to erect or control any other barrier to enter the market.[58]

The circumstances of a particular situation may also be examined for actual or potential abuses resulting from self-dealing or reciprocal dealing,[59] as well as whether procedures existed that would have permitted competitive forces in the marketplace to act.[60]

A. Market Power In Generation

The availability of viable alternative power supply options is paramount in determining whether the seller is a dominant firm in the sale of generation services in the market. The question of access to other supplies is also considered in some instances where generation market power is concerned. However, the access issue, particularly where the seller controls transmission facilities which the buyer would have to rely on to obtain supplies from alternative sources, is primarily a matter of transmission market power which is discussed in the following section.

An important element in this evaluation has been the competitive process under which the sales agreement between the parties was negotiated. Depending upon one's point of view, the Commission has acted either inconsistently or with flexibility in assigning weight to the competitive process in each situation. Nevertheless, it is important that evidence be offered to show that the negotiations or procurement process took place in competitive surroundings. Thus, in *Ocean State Power (Ocean State)*,[61] the rate for the sale of capacity to an unaffiliated buyer was found to have resulted from arm's length direct negotiations. Even though there were direct negotiations between the parties, as opposed to a formal bidding process, the Commission relied on the purchaser's review and consideration of alternative power supply sources for capacity, which included twenty-five projects unaffiliated with the selling project and its participants.[62]

In *Doswell Ltd. Partnership (Doswell)*,[63] the Commission examined whether a "market process" existed in connection with the purchaser's solicitation for capacity, which had resulted in twenty-seven offers from QF devel-

58. *See, e.g.*, Enron Power Enter. Corp., 52 F.E.R.C. ¶ 61,193, at 61,708 (1990).

59. *Id.*

60. *Cf.* Nevada Sun-Peak Ltd. Partnership, 54 F.E.R.C. ¶ 61,264, *order granting and denying reh'g and accepting rates*, 55 F.E.R.C. ¶ 61,058 (1991) (utility approached only two potential suppliers, and one did not bid on project).

61. Ocean State Power, 44 F.E.R.C. ¶ 61,261 (1988).

62. *Id.* at 61,981 n.17. The Commission also considered the generally competitive nature of the procurement process in the New England region, and the diverse fuel mix of the alternative supply sources available to the purchaser. *Id.* at 61,981.

63. Doswell Ltd. Partnership, 50 F.E.R.C. ¶ 61,251 (1990).

opers. The rate agreed to by Doswell and the purchasing utility was to track the utility's avoided costs relating to a plant under construction. The Commission refused to accept the avoided cost rate from the solicitation as just and reasonable under the FPA since the solicitation had been for QF projects, and instead performed its own market power analysis. A "market process" was found to have existed because the purchaser had discretion to restructure its solicitation after initial responses were received from developers, the seller had discretion to present a lower price as a potential inducement to increase its chances of being chosen by the purchaser, and nonprice terms (pertaining, for example, to matters of dispatchability and performance) which helped lower the total effective cost of each supply option were negotiated.[64] Having thus established that the entire process took place in a competitive environment, the Commission proceeded to find no evidence that the seller, or its predecessor, was a dominant firm in the generation market. The seller was not able to prevent the purchaser from reaching competing suppliers because neither the seller nor an affiliate owned or controlled transmission facilities in or around the purchaser's service area.[65] In addition, both the seller and its predecessor were new in the market and were not able to exercise market power over the purchaser by withholding services because the purchaser had alternatives available, including options to buy from others at the same price or to self-construct generating facilities.[66]

A determination of the existence of market power over generation has been less difficult for the Commission to find where the seller participated in and "won" a formal all-source bidding procedure. The competitive nature of such a procedure may create an environment conducive to a favorable finding for the use of market-based rates. In *Commonwealth Atlantic Ltd. Partnership (Commonwealth)*,[67] the purchasing utility sought bids for 1750 mw of capacity and energy and received bids for 95 projects representing nearly 15,000 mw of capacity. The solicitation had been structured in accordance with guidelines issued by the state commission which recommended that the bidding process be formulated around competitive negotiation. In this situation, the Commission found a lack of market power by the seller after examining the total capacity bid, the cumulative capacity offered to the purchaser, and the number of bids ultimately selected, concluding that the purchaser had additional alternatives from which to choose.[68] A lack of market dominance in generation was relatively easy to find in these circumstances, where the purchaser had received responses to its solicitation from IPPs, QFs, and electric utilities.

The Commission also had the opportunity in *Enron Power Enterprise Corp. (Enron Power)*[69] to address a proposal for market-based rates where the sale resulted from a solicitation by the purchaser. No state commission

64. *Id.* at 61,757. In a concurring opinion, Commissioner Trabandt indicated that there was insufficient factual support in the record to support this "market process" conclusion, and that the majority's decision on this point was based on conjecture. *Id.* at 61,761.

65. *Id.* at 61,757.

66. *Id.* at 61,758.

67. Commonwealth Atl. Ltd. Partnership, 51 F.E.R.C. ¶ 61,368 (1990).

68. *Id.* at 62,444.

69. Enron Power Enter. Corp., 52 F.E.R.C. ¶ 61,193 (1990).

approval was necessary for the seller's proposal, and the purchaser structured its own solicitation for power. The Commission noted:

> NEPCO used a procurement process that combined elements of bidding and negotiation. Regardless of what type of process is used, our key concern is to satisfy ourselves that the outcome resulted from a procurement process in which the seller lacked market power and there was no evidence of favoritism attributable to affiliation or joint ventures, such as self-dealing or reciprocal dealing.[70]

The seller was not found to be a dominant firm for purposes of generation market power as a result of the level of competition in the solicitation process, which reflected the small percentage of total capacity represented by the seller's bid and the fact that numerous bids were rejected by the purchaser.[71] A lack of market power was further supported by the purchaser's use of other sources to satisfy its requirements, even though the seller could have met the purchaser's entire need.[72]

The Commission also examined market power in generation markets by reference to contemporaneous solicitations for capacity by the purchaser from other classes of generators. Thus a seller, which was not a QF, was not found to be a dominant supplier where its direct negotiations with the purchaser were held at the same time the purchaser made a solicitation for QF capacity, which prompted bids for over twelve times the capacity sought in the solicitation.[73] Even though the solicitation was limited to QFs, the buyer was in a position to weigh those bids against the seller's own offer, and make a considered decision.[74]

Despite the fact that many of the preceding orders make specific reference to the number of bids made and capacity associated with those bids, the Commission clarified that it is not interested in playing a numbers game. Thus, in *TECO Power Services Corp. (TECO)*, the Commission originally found that only eight bidders responded to a solicitation by the purchaser, and only three of those represented actual, viable options.[75] On rehearing, the Commission denied that it used a "sparseness" test for evaluating generation market power:

> [T]he Commission did not intend to apply a rigid numerical "sparseness test" in the original order, nor does the Commission consider that a rigid numerical test is appropriate in determining whether a bidding program is sufficiently subscribed to allay our concerns about market dominance in generation. In reviewing a bidding program the Commission considers all of the circumstances surrounding the solicitation and response. However, as discussed in the original order, the Commission believes that a relatively low response rate provides a warning flag that dominance may be a problem or that there may have been

70. *Id.* at 61,708 n.44.

71. *Id.* at 61,708.

72. *Id.* at 61,708-09. The Commission also found that market power was lacking because of the purchaser's ability to negotiate favorable non-price terms, which included the right to suspend obligations, the right to future termination of the agreement, and the right to receive capacity charge reductions. *Id.* at 61,709.

73. Dartmouth Power Assocs. Ltd. Partnership, 53 F.E.R.C. ¶ 61,117, at 61,359 (1990).

74. *Id.*

75. TECO Power Servs. Corp., 52 F.E.R.C. ¶ 61,191, at 61,699, *order denying reh'g and accepting agreements*, 53 F.E.R.C. ¶ 61,202 (1990).

> hidden barriers to entry—either of which would call for further investigation. Thus, while a low response rate is not determinative of market power, it is potentially symptomatic of market power and must be carefully investigated.[76]

In *Public Service Co. of Indiana (PSI)*,[77] the Commission analyzed generation market power and what constitutes competing supplies in the context of market-based rates proposed by a electric utility, and it reviewed various components of the seller's market, including product, geographic, and future markets. In the product market analysis, all products capable of substitution for long-term firm bulk base-load power would be considered, with excess generation capacity held to be the measure of the product market.[78] The geographic market was defined by the customer's ability to obtain transmission to connect it to relevant generation sources, which were sources able to deliver comparable generation at a competitive price.[79] Projections of future market share were subject to uncertainty and speculation.[80] The Commission concluded that the seller did not have market power in generation because: (1) its share of excess generating capacity in the region was small; (2) the seller's customers would be able to access alternative suppliers inside and outside the region, including new units built in response to increased demand or an exercise of market power by the seller; (3) eligible customers were sophisticated in the acquisition of alternative resources in the market; and (4) the seller agreed to file a transmission tariff which was "essential" to the mitigation of seller's market power in the relevant sales.[81] The importance of this last point was highlighted by the Commission's statement that the ability of the seller's customers to reach alternative sources of supplies, together with the absence of significant barriers to entry, is more important than projections of market share.[82]

What generating sources constitute true alternatives for generation market power purposes was considered in *Portland General Exchange, Inc. (Portland General Exchange)*.[83] Ruled out as "viable and comparable" alternatives by the Commission were certain past suppliers of the purchaser which were not shown to have the necessary capacity or interest to make the sales themselves, and power from future sources. With respect to the remaining poten-

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76. 53 F.E.R.C. ¶ 61,202, at 61,810 (1990).

77. Opinion No. 349, Public Serv. Co. of Ind., 51 F.E.R.C. ¶ 61,367, *order on reh'g*, Opinion No. 349-A, 52 F.E.R.C. ¶ 61,260, *clarified and modified*, 53 F.E.R.C. ¶ 61,131, *appeal pending sub nom.* Northern Ind. Pub. Serv. Co. v. FERC, No. 90-1528 (D.C. Cir. Nov. 9, 1990) [hereinafter Opinion No. 349].

78. 51 F.E.R.C. ¶ 61,367, at 62,205. The Commission also considered market power in the context of seller's control of excess capacity in Pacific Gas and Elec. Co., 53 F.E.R.C. ¶ 61,145, at 61,501 (1990), and indicated that the most sound starting point to assess a seller's market over a buyer in generation is to determine how that buyer meets its current requirements. Although the buyer in *Pacific Gas and Elec. Co.* controlled a significantly greater percentage share of excess capacity than the seller in PSI, the existence of other supply sources lessened the impact of the seller's control, and led to a conclusion that the seller would not be able to exercise market power over the purchaser. 53 F.E.R.C. ¶ 61,145, at 61,502.

79. Opinion No. 349, *supra* note 77, 51 F.E.R.C. ¶ 61,367, at 62,206.

80. *Id.* at 62,208.

81. *Id.* at 62,209.

82. *Id.* at 62,208.

83. Portland Gen. Exch., Inc., 51 F.E.R.C. ¶ 61,108, *order granting clarification*, 51 F.E.R.C. ¶ 61,379, *order on compliance*, 53 F.E.R.C. ¶ 61,216 (1990).

tial alternative supplies, the Commission indicated that firm transmission access is a prerequisite for finding that another supplier is a viable alternative.[84] In this light, the Commission examined the potential alternative suppliers and found that four suppliers, other than the seller, had offered to sell to the purchasers from existing sources, had firm access rights to key transmission facilities, and appeared to hold firm surplus transmission capacity at the point the seller and purchasers entered into their agreements. The Commission also found two other potential suppliers which could have gained access to important transmission facilities. Although these six potential alternative suppliers had not offered service exactly similar to that in the seller's offer, the purchasers were found to be sufficiently able to adapt to the service that the alternative suppliers could have provided, thus leading to a conclusion that the seller had not exercised generation market power.[85]

Whether sufficient access to transmission exists in order to make a potential alternative supplier a truly viable alternative has been raised in other proceedings where generation market power was addressed. In *Terra Comfort Corp. (Terra Comfort)*,[86] a lack of market power in generation was not found where otherwise potential alternate suppliers lacked transmission access to the purchaser. All but one alternative supplier that offered to sell power in response to the purchaser's solicitation would have required transmission access through another utility, and no evidence was submitted by the seller to prove that the required intervening transmission service would, in fact, be provided.[87] In *Pacific Gas & Electric Co. (PG&E/SMUD)*,[88] an interconnection in agreement between PG&E and the Sacramento Municipal Utility District (SMUD) concerned coordination services to be offered at market-based rates. In assessing PG&E's market power in generation, the Commission found that SMUD had access to firm transmission service for its own resources in order to make purchases in other geographical areas.[89]

A seller must also present evidence of actual, and not merely potential, alternative generation sources to show a lack of market power. The Commission in *Nevada Sun-Peak Ltd. Partnership (Nevada Sun-Peak)* rejected arguments that the seller, in effect, competed against all developers in the country that build generating units, and held that evidence of self-construction alone does not show that the seller lacked market power.[90] What makes this decision appear harsh is that it was the buyer who decided that there was insuffi-

84. 51 F.E.R.C. ¶ 61,108 at 61,248.

85. *Id.* at 61,248-51. Among the factors considered were whether these alternate suppliers had access to the purchasers, if they could sell on a long-term basis, and whether the energy prices offered reflected the costs of fossil, baseload units. *Id.* at 61,250-51. As discussed elsewhere in this article, other portions of the proposal concerning Portland General Exchange and an affiliate were found to involve the potential and incentive to engage in preferential dealing.

86. Terra Comfort Corp., 52 F.E.R.C. ¶ 61,241 (1990). As discussed elsewhere in this article, in *Terra Comfort* the Commission also addressed affiliation and preferential pricing issues.

87. *Id.* at 61,841.

88. Pacific Gas and Elec. Co., 53 F.E.R.C. ¶ 61,145 (1990).

89. *Id.* at 61,501.

90. Nevada Sun-Peak Ltd. Partnership, 54 F.E.R.C. ¶ 61,264, at 61,769, *order granting and denying reh'g and accepting rates*, 55 F.E.R.C. ¶ 61,058 (1991).

cient time for a formal solicitation and approached the seller about acquiring additional capacity. However, this circumstance did not relieve the seller of its burden to demonstrate a lack of market power in the relevant market:

> The Commission recognizes that Sun-Peak's inability to meet the evidentiary requirements here is due at least initially to Nevada Power's actions. However, any supplier seeking market-based rates is affected by the actions of its buyers. When buyers conduct a well-organized and comprehensive market search, either by competitive bidding or negotiation, they can provide the supplier with much of the needed evidence. When buyers limit their options, the supplier's evidentiary task is more difficult. Whatever the cause, however, Sun-Peak has not, based upon the current record, met its evidentiary burden as to generation dominance and cannot receive market-based rates.[91]

Thus, the Commission concluded that the seller failed to demonstrate that it lacked market dominance.

In *Cleveland Electric Illuminating Co. (Cleveland)*,[92] the Commission looked to a buyer's purchase pool obligation to determine whether the seller was a dominant supplier in the sale of generation. In addition, the fact that the combination of any two offers to sell could have fulfilled the purchaser's requirements also was relied on by the Commission in finding that there was a lack of generation market power. This last finding is noteworthy because only two entities other than the seller offered service to the purchaser.[93] In contrast, in earlier Commission proceedings where generation market power was addressed, such as *Doswell* and *Commonwealth*, the Commission valued the high number of parties that responded to a solicitation or similar procedure. But, the decision in *Cleveland* appears consistent with the discussion on rehearing in *TECO*, where the Commission declined to apply a "sparseness" test with respect to reviewing bidding programs but would instead consider all circumstances associated with the transaction.

B. Market Power In Transmission

Market power also arises from the seller's ability to block a buyer from competing suppliers. If a seller can effectively stop a purchaser from gaining access to alternative supplies, the seller's own position in the marketplace is enhanced and the ability to prevent downward pressure on rates is increased. Thus, ownership or control of transmission facilities has been said to constitute the "most likely route" to market power in the electric utility industry.[94]

Market power may stem either from the control of transmission facilities through direct ownership or gaining rights of control through contract.[95] In

91. 54 F.E.R.C. ¶ 61,264, at 61,769-70. On rehearing, the Commission found the seller's rates to be justified on a cost basis, and thus did not address further the issue of the seller's market power. 55 F.E.R.C. ¶ 61,058, at 61,162. In fact, the Commission indicated that it was unable to respond to matters raised in rehearing applications to its first order because Nevada Sun Peak had requested the Commission either disclaim jurisdiction or authorize the disposition of the general partnership interest in the project to a new corporation. *Id.* at n.13.

92. Cleveland Elec. Illuminating Co., 55 F.E.R.C. ¶ 61,172 (1991).

93. *Id.* at 61,553.

94. Citizens Power & Light Corp., 48 F.E.R.C. ¶ 61,210, at 61,777 (1989).

95. *Id.*

either case, the entity controlling those transmission facilities or access thereto may be able to "withhold supply and exact monopoly prices."[96] Market power also may be enhanced by a seller's failure to make an affirmative offer to provide transmission services:

> A utility's control over transmission facilities, through its own actions or the actions of others, can deter competitors and put the utility in a position to influence the power sale price, even if other competitors exist. Further, an alternative supplier may be deterred not only by a direct refusal by the controlling utility to provide access, but also by the fact that the utility controlling transmission has made no general offer of transmission availability which would provide the opportunity for others to request service to be used in competing for wholesale sales.[97]

Where a seller has market power in transmission, that power must be mitigated in order for market-based aspects of the sale to be approved as just and reasonable.[98]

A seller has been held to lack market power with respect to transmission where it, or an affiliate, does not own or control transmission facilities in or around the purchaser's service area or in the region where the purchaser located.[99] As a part of its examination of market power in transmission, the Commission has looked to whether an alternative source of generation for the purchaser has adequate transmission service available to gain access to the purchaser without having to use transmission facilities of any of the participants in the seller's project.[100]

As previously discussed, the selling utility's agreement to file a transmission tariff to increase the alternatives available to its customers formed a significant basis for the Commission's approval of market-based pricing provisions for other services in PSI.[101] There, Public Service Company of Indiana PSI, a utility, in conjunction with a proposed sale of firm power at market-based rates, committed to provide long-term service over its transmission facilities so certain utilities could obtain bulk power elsewhere. The agreement by PSI to file this transmission tariff, whereby other utilities could obtain access to a supplier other than PSI, formed a significant basis for the Commission to conclude that PSI had mitigated its market power over transmission.[102]

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96. *Id.*

97. Portland Gen. Exch. Inc., 51 F.E.R.C. ¶ 61,108, at 61,251 (footnote omitted).

98. *See, e.g.*, Pacific Gas and Elec. Co., 53 F.E.R.C. ¶ 61,145, at 61,503 (1990).

99. *See, e.g.*, Dartmouth Power Assocs. Ltd. Partnership, 53 F.E.R.C. ¶ 61,117 at 61,360 (1990); Enron Power Enter. Corp., 52 F.E.R.C. ¶ 61,193, at 61,709 (1990); Commonwealth Atl. Ltd. Parnership, 51 F.E.R.C. ¶ 61,368 at 62,244 (1990); Doswell Ltd. Partnership, 50 F.E.R.C. ¶ 61,251, at 61,757 (1990). *See also* Cleveland Elec. Illuminating Co., 55 F.E.R.C. ¶ 61,172, at 61,554 (1991) (no market power in transmission where seller does not own or control transmission facilities within power pool system.).

100. Ocean State Power, 44 F.E.R.C. ¶ 61,261, at 61,982 n.21 (1988). In addition, the existence of guaranteed access to power pool generation facilities for the purchaser has been considered a relevant consideration in a market power analysis. *Id.* at 61,982.

101. Opinion No. 349 *supra* note 77, 51 F.E.R.C. ¶ 61,367, at 62,226.

102. *Id.* at 62,225. The Commission has conditioned its approval of a proposed merger upon the availability of transmission commitments offered by one of the parties in order to mitigate the anticompetitive effects of the merger. Opinion No. 364, Northeast Utils. Serv. Co., 56 F.E.R.C. ¶ 61,296

The Commission also has approved flexible pricing provisions for coordination power service but required the undertaking of conditions to mitigate market power in transmission. In *Pacific Gas and Electric Co. (PG&E/Turlock)*,[103] the Commission approved an agreement whereby Pacific Gas & Electric Company (PG&E) would sell power to a captive customer, the Turlock Irrigation District (Turlock), with the condition that Turlock have at least one potential alternative supplier before PG&E could charge flexible prices. The condition was removed after the Commission determined that reserved (firm) transmission service would be available from PG&E to Turlock for all types of transactions, which would provide Turlock access to significant alternative suppliers.[104]

In another proceeding involving an agreement for the sale of coordination power services, this time between PG&E and the Modesto Irrigation District (Modesto),[105] the Commission required PG&E to provide assurances relating to the availability of reserved transmission service for Modesto before it would accept a flexible pricing provision. The Commission indicated that such assurances could be provided if the parties showed, first, that the initial reserved transmission service available to Modesto (plus its own general and firm contracts) was sufficient to meet Modesto's projected load for three years, and, second, that the agreement between the parties had been amended to provide that flexible pricing would not be permitted if, during the twenty year term of the service agreement, the reserved transmission service and other resources were insufficient to meet Modesto's load because additional reserved transmission service was not available. As an alternative method of assurance, the Commission recognized that the agreement could be amended to provide firm service of the type approved in *PG&E/Turlock*.[106]

In *PG&E/SMUD*, the Commission approved the interconnection agreement which pertained to certain service to be provided by PG&E, including coordination power services. To mitigate transmission market power, however, the Commission required three modifications in order to approve the market-based portions of the proposal. Foremost among these was the requirement that pricing flexibility would be available only when reserved transmission service is provided, thus eliminating a provision that would have allowed PG&E to withhold such firm transmission service until SMUD, the

slip op. at 45, 49 (1991). *See also* Opinion No. 318, Utah Power & Light Co., 45 F.E.R.C. ¶ 61,095 (1988), *order on reh'g*, Opinion No. 318-A, 47 F.E.R.C. ¶ 61,209, *order on reh'g*, Opinion No. 318-B, 48 F.E.R.C. ¶ 61,035 (1989), *remanded sub nom.* No. 89-1333 (D.C. Cir. Aug. 2, 1991) (the Court of Appeals did not deny the Commission the ability to condition a merger approval with a transmission access condition, but remanded for further consideration of the Commission's exclusion of QFs and end-users from access to firm transmission).

103. Pacific Gas and Elec. Co., 42 F.E.R.C. ¶ 61,406, *order granting reh'g in part and denying reh'g in part and clarifying previous order*, 43 F.E.R.C. ¶ 61,403 (1988). The coordination service here were all services provided by PG&E other than obligation service (firm capacity) and reserved transmission service. Coordination services included both capacity and energy, and transmission services. 42 F.E.R.C. ¶ 61,406, at 62,192.

104. 43 F.E.R.C. ¶ 61,403, at 62,034.

105. Pacific Gas and Elec. Co., 44 F.E.R.C. ¶ 61,010, *order on reh'g and on compliance*, 45 F.E.R.C. ¶ 61,061 (1988), *order on compliance*, 46 F.E.R.C. ¶ 61,390 (1989).

106. 45 F.E.R.C. ¶ 61,061, at 61,205.

purchaser, incurred a resource deficiency.[107] PG&E also was required to remove certain restrictions in the use of reserved transmission service for exports by SMUD. The Commission found that the restriction not only enhanced PG&E's market power over SMUD, but also improved PG&E's market power with respect to its coordination power services in the area.[108] As an additional condition, the Commission ordered PG&E to remove a provision from the interconnection agreement which prohibited SMUD from reassigning reserved transmission service, because operation of the provision could have discouraged SMUD from using PG&E's transmission services to purchase from other suppliers.[109]

The question of transmission access where market-based pricing is involved has also been present where certain broad-based experiments have been authorized to test competition. In a proceeding involving the Western Systems Power Pool (WSPP), the Commission accepted, for two years, a filing by the WSPP to implement an experiment that included market-based pricing for coordination and transmission services.[110] When the members in the WSPP, which included numerous public utilities subject to Commission jurisdiction, sought to make permanent much of the experiment, the Commission rejected further use of market-based rates because WSPP had not met its burden to demonstrate that the WSPP participants lacked, or adequately mitigated, market power in generation and transmission.[111] First, an exercise of market power in the WSPP was found to exist by the member's practice of charging captive utilities more than was charged other utilities for power and short-term transmission services.[112] Second, owners of transmission could charge more for short-term transmission services when levels of available transmission capacity were low, which provided insufficient incentives for the expansion of transmission capacity.[113] Third, the Commission found that the availability of long-term transmission at cost-based rates could help discipline rates for short-term transmission services.[114]

Furthermore, it was determined that transmission principles proposed by the members would not adequately mitigate market power because the participants in the WSPP were not required to provide any transmission service and,

107. Pacific Gas and Elec. Co., 53 F.E.R.C. ¶ 61,145, at 61,503 (1990).

108. *Id.* at 61,504.

109. *Id.* at 61,505. In a partial dissent, Commissioner Trabandt viewed the last two restrictions as "regulatory overkill," stating that these restrictions had no relationship to finding a competitive market, and questioned the Commission's authority to use a rate filing to open transmission for purposes of efficiency. *Id.* at 61,507-10.

110. Pacific Gas and Elec. Co., 38 F.E.R.C. ¶ 61,242 (1987). Extensions of the experiment were later granted. *See* Pacific Gas and Elec. Co., 47 F.E.R.C. ¶ 61,121 (1989); Pacific Gas and Elec. Co., 50 F.E.R.C. ¶ 61,339 (1990). Earlier, the Commission also approved an experiment involving mandatory transmission access where the proposal included pricing two bulk power services at market-based rates. Opinion No. 203, Public Serv. Co. of New Mexico, 25 F.E.R.C. ¶ 61,469 (1983), *reh'g denied*, Opinion No. 203-A, 27 F.E.R.C. ¶ 61,154 (1984).

111. Western Sys. Power Pool, 55 F.E.R.C. ¶ 61,099, *order granting in part and denying in part reh'g*, 55 F.E.R.C. ¶ 61,495 (1991).

112. 55 F.E.R.C. ¶ 61,099, at 61,316.

113. *Id.*

114. *Id.* at 61,316-17.

thus, purchasers could not be guaranteed transmission with regard to service from other suppliers. Specifically, the availability of transmission would be in the transmitter's sole discretion which would not be subject to arbitration, transmission reassignments were subject to unreasonable restrictions, and sellers could not request transmission service.[115] In making these findings, the Commission rejected arguments that it was seeking to implement "perfect" competition. Rather, the Commission indicated that its own standard was "less restrictive and more realistic" because it tolerates "some market imperfections as long as the Commission is assured that the seller requesting market-based rates is not able to influence significantly the price to the buyer."[116] In sum, the WSPP's market-based rate ceilings were rejected because the WSPP did not provide adequate data regarding generation market power and did not consider adequate measures to mitigate transmission market power. Thus, the WSPP was directed to agree to cost-based price ceilings for coordination energy, transmission, and exchange services as a condition to acceptance of the WSPP agreement.

The existence of interconnections between the purchaser and other utilities does not guarantee that a seller lacks transmission market power where market-based rates are concerned. In *Terra Comfort* the existence of six interconnections between the purchaser and other utilities did not demonstrate the absence of market power in transmission. Whereas such interconnections may evidence a lack of market power with respect to generation, it is neither evidence of available transmission nor evidence of a lack of transmission market power.[117] Several other relevant factors were identified which contributed to the Commission's inability to find a lack of market power in this instance: (1) that a lack of requests for transmission service does not show a lack of market power, whereas a "positive offer" of transmission access is by far more convincing evidence of mitigation of market power; (2) a party's ability to mandate arbitration in connection with the use of a transmission facility renders use of that facility uncertain and does not diminish market power over transmission; and (3) a transmission path to an interconnection with a potential alternate supplier is not considered accessible where that interconnecting party has no "generally available transmission tariff."[118] The Commission further held that market power in transmission may mean that lack of access prevents a purchaser from considering least-cost alternative supplies and from realizing other benefits of competition:

> Iowa Electric [the purchaser] could also be foreclosed from considering competing suppliers with costs higher than the Applicants' but lower than the alterna-

115. *See* 55 F.E.R.C. ¶ 61,495, at 62,715.

116. *Id.* at 62,714.

117. Terra Comfort Corp., 52 F.E.R.C. ¶ 61,241, at 61,841-42. In a concurring opinion, Commissioner Trabant takes the more realistic approach that the Commission had before it more than mere "evidence of interconnections," and that the purchaser could have obtained transmission access. This reasoning is based, in part, on the ability of the purchaser to obtain power from other entities through the interconnections. *Id.* at 61,844-45.

118. *Id.* Commissioner Trabandt disavowed that portion of the order which creates a standard that forces utilities that "win" in a bidding process "to open their own transmission systems to all corners, or show that their neighbors have done so." *Id.* at 61,845-46 (Trabandt, Comm'r, concurring).

> tives accessible to Iowa Electric without Iowa Southern's [one of the sellers] transmission system. While a competing supplier with costs higher than the Applicants' costs could not supplant the Applicants as sellers, that competitor can exert a downward pressure on the market price that the Applicants can demand. Accordingly, if Iowa Southern can block such a competitor, the Applicants' influence over the price is enhanced.[119]

The potential for transmission market power in situations where affiliate relationships are present has also been closely monitored. This occurred in *TECO* where Tampa Electric Company (Tampa Electric) proposed to sell bulk power to its affiliate, TECO Power Services Corporation (Power Services), at market-based rates, and Power Services, in turn, would sell that bulk power together with other capacity and energy to a non-affiliated purchaser, Seminole Electric Cooperative (Seminole).[120] Tampa Electric was found to control transmission access in its service territory and was in a position to prevent possible alternative suppliers from seeking to respond to a solicitation made by Seminole. In addition, the Commission was unable to hold that Tampa Electric had mitigated its control of transmission because Tampa Electric had not offered transmission access to competing suppliers.[121]

In *Portland General Exchange*, in order to determine whether a marketer/seller of electricity services to two municipal customers had market power, the Commission found it necessary to establish with certainty whether the marketer, or its affiliate which was in the business of providing transmission services, controlled transmission to the point of controlling trade and influencing the price of the sale. Under these circumstances, and in reasoning similar to that in *TECO*, if the affiliate, Portland General Electric Corporation (Portland General Electric), had offered to provide "long-term firm, cost-based access over critical transmission paths to any interested utility," then the Commission could have concluded with sufficient certainty that there was not significant market power in transmission services to enhance the competitive position of the affiliate.[122] However, since there was no proof that such an offer was made, the Commission examined circumstances surrounding the "critical transmission facility"—in this case an intertie—to determine whether the two municipal customers could have accessed other suppliers through that facility, or whether the marketer or its affiliate could have exercised significant market power through its own capacity in that facility.[123] Although Portland General Electric was able to control access to the intertie because of its own capacity rights therein, its ability to exercise transmission market power was mitigated by the availability of capacity in the intertie from other parties, which could have been sold to competitors of Portland General Electric and its affiliate.[124]

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119. *Id.* at 61,842.

120. TECO Power Serv. Corp., 52 F.E.R.C. ¶ 61,191, at 61,700 (1990). In its rehearing order in *TECO*, the Commission accepted the rate proposals, as modified, on a cost-of-service basis. 53 F.E.R.C. ¶ 61,202, at 61,811 (1990).

121. 52 F.E.R.C. ¶ 61,191, at 61,700.

122. Portland General Exch. Inc., 51 F.E.R.C. ¶ 61,108, at 61,251 (1990).

123. *Id.* at 61,251-2.

124. *Id.* at 61,251.

Even where a seller does not presently have market power over transmission facilities, it may be required to continually justify a lack of such market power. This appears to be particularly true in the case of a marketing entity that is the seller of electric power. Although the market may have been found to lack market power over transmission facilities, the Commission has imposed conditions to safeguard against changes in contractual arrangements and corporate structure that could subsequently enhance the market power of the marketing entity.[125] Since market power could be gained in the future through various individual contracts, approval of the market-based pricing aspects of the marketer's proposal was conditioned upon the submission of informational filings to the Commission concerning purchase and sale agreements as a monitor of future market power.[126]

C. Barriers to Entry

In order to establish a lack of market power the seller and its affiliate must also demonstrate that they are not able to erect or otherwise control any other barrier to entry. Such barriers could result from control of major inputs to electricity production by competing generation sources or the transportation of those inputs.[127] Control could be exerted through ownership or the ability to influence the use of various properties or entities, including land sites for generating facilities, natural gas suppliers, natural gas pipelines and other fuel and delivery systems, and generating equipment.[128]

A combined gas and electric utility may be in a position to erect barriers to entry and, therefore, will be scrutinized by the Commission when sales of electric services are proposed in connection with market-based price levels.[129] Barriers to entry have not been found where an array of energy sources for generating electricity may be available as alternative sources, or existing state regulations are favorable to encourage the availability of natural gas transportation capacity to potential competing generation sources.[130]

A purchaser's broadly publicized solicitation open to a number of technologies, fuels, and categories of potential suppliers has been found to constitute an affirmative effort to remove barriers.[131] On the other hand, a utility's decision to offer capacity only to its affiliate, which then would resell that capacity "bundled" together with other services, prevented other potential non-affiliated bidders from presenting their own alternative package of "bun-

125. Citizens Power & Light Corp., 48 F.E.R.C. ¶ 61,210, at 61,777-78 (1989).

126. *Id.* at 61,778. Additional safeguards also were found to exist by the ability of interested parties to intervene in future proceedings involving sales of energy or transmission to the marketer, or through the filing of a complaint alleging abuse of market power.

127. *See* Enron Power Enter. Corp., 52 F.E.R.C. ¶ 61,193, at 61,709; Commonwealth Atl. Ltd. Partnership, 51 F.E.R.C. ¶ 61,368, at 62,245 n.51 (1990).

128. *See, e.g.*, Pacific Gas and Elec., 53 F.E.R.C. ¶ 61,145, at 61,505 (1990); Dartmouth Power Assocs. Ltd. Partnership, 53 F.E.R.C. ¶ 61,117, at 61,360 (1990); Enron Power Enter Corp., 52 F.E.R.C. ¶ 61,193, at 61,709 n.47 (1990); Doswell Ltd. Partnership, 50 F.E.R.C. ¶ 61,251, at 61,758 (1990).

129. *Pacific Gas*, 53 F.E.R.C. ¶ 61,145, at 61,506.

130. *Id.*

131. *Commonwealth*, 51 F.E.R.C. ¶ 61,368 at 62,245.

dled" services.[132] This amounted to a barrier to entry, resulting in the potential for the affiliate's use of market power. As explained in the immediately following section, an affiliate's potential exercise of market power where market-based pricing is proposed has been a major concern to the Commission.

IV. CONCERNS WITH AFFILIATION AND SELF-DEALING

Two potential violations of the FPA are commonly identified as associated with rates where affiliate transactions are concerned. The first, that the requirement of just and reasonable rates under section 205(a) of the FPA may be violated where rates are market-based and the seller, either by itself or through an affiliate, is able to exercise market power, has been addressed in preceding sections of this article. The second, self-dealing or reciprocal dealing due to affiliations, may result in a violation of the prohibition in section 205(b) of the FPA against unduly discriminatory or preferential rates and is considered in this section.[133]

When market based rates are proposed, a power producer's affiliation with a franchised utility "raises a warning flag."[134] Indeed, the Commission has stated that where an applicant seeks approval for market-based pricing in a transaction involving an affiliate, it is appropriate to utilize a standard whereby the mere opportunity for undue preference will lead to rejection of the proposal.[135] Harm could result because an affiliate relationship may be used to increase market power and prevent entry by a competitor:

> [S]uch affiliation only becomes a problem when there are transactions or locational considerations that can give rise to favoritism. The Commission's concern is not with the affiliation per se but with the abuses that may arise when the affiliates do business together or when the affiliated utility uses its control over transmission or some other entry barrier to block others from competing against its affiliate.[136]

The Commission has also discussed the profit motive associated with affiliation and how such financial pressures come to distort and disrupt market forces:

> [W]hether . . . [a seller] has market power over the affiliated purchasers is not in itself dispositive of whether we can rely on market forces in establishing just and reasonable rates to those purchasers. When a purchaser is affiliated with a seller, the purchaser might agree to pay a higher price than it would otherwise agree to pay because the purchaser would financially profit from the transaction.[137]

Thus, for example, a purchaser with captive downstream customers could attempt to pass through to those customers prices paid an affiliate, where the affiliate relationship may have altered ordinary market forces.[138] In this

132. TECO Power Serv. Corp., 52 F.E.R.C. ¶ 61,191, at 61,700 (1990).

133. *See, e.g.*, Terra Comfort Corp., 52 F.E.R.C. ¶ 61,241, at 61,836 (1990); *TECO*, 52 F.E.R.C. ¶ 61,191, at 61,697.

134. *Commonwealth*, 51 F.E.R.C. ¶ 61,368, at 62,245.

135. TECO Power Serv. Corp., 53 F.E.R.C. ¶ 61,202, at 61,809 (1990). *See also* Portland Gen. Exch. Inc., 51 F.E.R.C. ¶ 61,108, at 61,246 n.66 (1990).

136. *Commonwealth*, 51 F.E.R.C. ¶ 61,368, at 62,245.

137. Ocean State Power, 44 F.E.R.C. ¶ 61,261, at 61,983 (1988) (footnote omitted).

138. *Id.* at n.27.

regard, the Commission stated:

> Self-dealing occurs when a marketer sells to or buys from an affiliate on terms that are more favorable than those that would be available to other market participants. The difference between the price paid by the affiliate and the market price is then passed along to captive customers. Affiliates have the incentive to do this because they have the same goal: maximize profits for the parent firm. Pricing flexibility would increase the chances that an affiliated marketer could successfully engage in self-dealing.[139]

Abuses from self-dealing may result from affiliations between: (1) the seller and a franchised utility, (2) the seller and a supplier of key inputs associated with the generation of electricity, or (3) the seller and a firm that transports key inputs.[140] These concerns may be alleviated where the seller is not affiliated with any entity that has a franchised service area, which eliminates the incentive for a purchaser to pay an inflated price to an affiliate because of the purchaser's ability to passthrough costs, especially where the purchaser resells to captive customers.[141] Self-dealing has not been found where the seller is not affiliated or involved in any joint venture with its purchaser or in a joint venture with a franchised utility in the purchaser's service area,[142] where the seller's proposal is not based on obtaining fuel from a gas utility affiliate,[143] or where the seller, although affiliated with a QF that will serve the purchaser, will not influence the price at which the purchaser buys power.[144]

In *Ocean State*, market-oriented pricing was addressed where the purchasers included utilities that were affiliates of the seller's general partners. To test whether the affiliation led to abusive practices, the Commission examined the rate paid by affiliates and non-affiliates for other services.[145] The Commission's evaluation of the price the affiliated purchasers would pay the seller over the life of each transaction indicated that the rates would be below each purchaser's avoided cost. Although concern was expressed over accepting a utility's own avoided cost projection, especially where the utility could benefit by inflating its projection, the affiliate projections were verified by other factors, including findings by the state regulatory commission, the lack of evidence that the rates exceeded the avoided costs of the purchasers, and the lack of protest of the pricing methodology. The rates to be charged the affiliated purchasers were further verified by comparison of those rates with the rates for Ocean State's sale to a nonaffiliate, Boston Edison.[146]

However, in other proceedings where non-cost of service rates were involved, sales between affiliates have been held unduly preferential in violation of section 205(b) of the FPA. In *Portland General Exchange*, the Com-

139. Citizens Power & Light Corp., 48 F.E.R.C. ¶ 61,210, at 61,777 (1989).

140. *Commonwealth*, 51 F.E.R.C. ¶ 61,368, at 62,245 (1990).

141. *Citizens*, 48 F.E.R.C. ¶ 61,210, at 61,777-78.

142. Doswell Ltd. Partnership, 50 F.E.R.C. ¶ 61,251, at 61,758 (1990).

143. *See* Enron Power Enter. Corp., 52 F.E.R.C. ¶ 61,193, at 61,709 (1990).

144. Dartmouth Power Assocs. Ltd. Partnership, 53 F.E.R.C. ¶ 61,117, at 61,360 (1990).

145. Ocean State Power, 44 F.E.R.C. ¶ 61,261, at 61,983 (1988). Also considered was whether an affiliated purchaser had received favorable treatment through terms and conditions of service. *Id.*

146. *Id.* at 61,984-85. The Commission found that the sale to Boston Edison was negotiated at the same time, and involved similar generating capacity, as the sale to the affiliated purchasers. *Id.*

mission refused to accept proposed rates for sales by Portland General Electric for electricity and electricity-related products to an affiliated power marketer, Portland General Exchange, Inc. (PGX), where the rates were not based on PGE's cost of service. The proposed sale by Portland General Electric to its marketing affiliate raised the potential for preferential dealing as a result of the affiliate's common goal of increasing profits for stockholders, which created an incentive to have the seller charge the affiliated purchaser as low a price as possible.[147] The Commission made key factual findings to support rejection of the proposed sale: the rate for the sale by Portland General Electric to PGX would account for much less than a 100 percent contribution to the seller's fixed costs; a discount provided to PGX by its affiliated seller probably was not required for PGX to make its own sale to its customers, two California cities; Portland General Electric's service to PGX, on the one hand, and PGX's service to the cities, on the other, were substantially similar, notwithstanding the fact that the rate for the sale to PGX was much lower than the rate the Cities would pay to PGX; and Portland General Electric failed to offer to other customers the rate to be charged to PGX.[148] Portland General Electric's efforts to justify its rates through comparison to other utility sales in the region also were rejected. Even assuming such other sales were similar to Portland General Electric's own sale to PGX, the Commission found that Portland General Electric failed to explain its reason for not offering to the two California cities terms of service similar to those offered its affiliate.[149]

While Portland General Electric's rates were rejected by the Commission, it was given the choice of one of two alternatives by which to remedy the unduly preferential result inherent in its earlier filing. First, Portland General Electric could reprice the service for PGX at the price that PGX and the two cities had agreed upon; second, Portland General Exchange could offer to the two cities the same rate that it had offered to PGX.[150] In either case, the resulting rate was ordered to be at a level not below 100 percent of Portland General Electric's fully allocated cost.[151]

The use of a market value test based either on offering services to nonaffiliates or establishing a benchmark price relating to similar services has been indicated. In *TECO*, three separate agreements were considered by the Commission: (1) the "BB4 Agreement," which was the sale of bulk power at market based rates by Tampa Electric Company (Tampa Electric) to its affiliate, TETCO Power Services Corporation (Power Services); (2) the "Seminole Agreement" for resale by Power Services to Seminole Electric Cooperative of the BB4 power at no markup, bundled together with a sale of capacity and energy at market based prices from combined cycle and combustion turbine units (the CC/CT 1 and 2 units); and (3) the "Tampa Electric Agreement" for the sale by Power Services to Tampa Electric of power from the CC/CT 1 and

147. Portland General Exch. Inc., 51 F.E.R.C. ¶ 61,108, at 61,245 (1990).

148. *Id.*

149. *Id.*

150. *Id.* Portland General Exchange eventually chose the first alternative, and thus, in effect, eliminated PGX from the proposal. Portland General Exch. Inc., 53 F.E.R.C. ¶ 61,216, at 61,862 (1990).

151. *Portland*, 51 F.E.R.C. ¶ 61,108, at 61,246.

2 units at market-based rates.[152] The BB4 and Seminole Agreements were considered together because of the "bundling" of the two resources—the BB4 and CC/CT 1 and 2—and the incentive for preferential pricing and potential for the parent of Tampa Electric and Power Services to adjust the combined price. The Commission reasoned that if the BB4 sale from Tampa Electric to Power Services had been priced too low, then Power Services could charge more for the sale of its own CC/CT 1 and 2 capacity and thus divert profits from Tampa Electric's ratepayers to the stockholders in Tampa Electric, Power Services, and their parent.[153] The fact that there was no markup by Power Services in the BB4 energy and capacity did not eliminate concerns with "trade-offs" in pricing:

> Because the BB4 entitlement was bundled with additional capacity and energy from CC/CT 1 and 2, and because Seminole evaluated the bundled products as a single transaction and price, *TECO* and its subsidiaries Tampa Electric and Power Services had the incentive and the opportunity to make tradeoffs in price between the two products. Here, the potential and incentives for self-dealing may have led Tampa Electric's parent *TECO* to make the revenue credit from the sale of BB4 as small as possible and the returns to shareholders from Power Services' sale of CC/CT 1 and 2 power as large as possible.[154]

Moreover, Tampa Electric was in a position to price the sale of BB4 power below market for another reason. Since Tampa Electric's native load customers already were responsible for the capital costs of the facility, the shareholders would not suffer any financial harm by underpricing the sale of BB4 power.[155]

To offset the incentive to underprice the BB4 services, the Commission stated that it would rely on a "market test" for transactions between affiliates:

> [I]n no instance will we accept a market price less than the variable cost of providing the service to the affiliate. To do otherwise would result in the utility's retail and wholesale requirements customers subsidizing the affiliate's costs. In addition, before the Commission will accept a market test for an affiliate transaction, the utility must show that it has not narrowed the market to validate a low transfer price.[156]

The temptation for "preferential manipulation" of rates because of the "bundling" of services was further highlighted by Tampa Electric's apparent failure to offer the BB4 power to anyone other than its affiliate.[157] If Tampa Electric had offered the BB4 power for sale independent of a solicitation made by Seminole, then all bidders, including Seminole, would have been able to propose similar combinations of capacity or any other alternative to the "bundling" offered on behalf of the affiliate, thus offering "greater assurance that market forces would discipline the bids offered to Seminole and that the opportunity for undue preferential pricing would be virtually eliminated."[158]

152. TECO Power Servs. Corp., 52 F.E.R.C. ¶ 61,199, at 61,692-93 (1990).
153. *Id.* at 61,697-98.
154. *Id.* at 61,698 n.45.
155. TECO Power Servs. Corp., 53 F.E.R.C. ¶ 61,202, at 61,809 (1990).
156. *Id.*
157. TECO Power Servs. Corp., 52 F.E.R.C. ¶ 61,199, at 61,698 (1990).
158. *Id.* at 61,699.

On these grounds, the Commission established a market-value test for a transaction between affiliates. The test employs two options. First, the seller may offer to all bidders the same services to be sold to its affiliate. Second, the seller may submit to the Commission evidence of a benchmark price that would represent the market value of similar services and which could be based on similar transitions by other utilities or by similar arm's-length transactions involving the seller itself.[159]

In *Terra Comfort*, a utility solicited proposals to meet its future power requirements and eventually decided to purchase services from two affiliates, Iowa Southern Utilities (Iowa Southern), an electric and gas utility, and Terra Comfort Corporation (Terra Comfort), which had no other customers. The three agreements were: (1) a Capacity and Energy Agreement for sale of 118 MW of unit power by Terra Comfort to the utility from combustion turbine units at levels above cost-based rates, (2) an Energy Agreement for sale of energy by 118 MW of energy to the utility by Iowa Southern, and (3) a Transmission Agreement relating to service to be provided by the two affiliates to each other.[160] Under the two power agreements the affiliates would provide 118 MW of capacity and energy, and the utility would be prohibited from scheduling more than 118 MW from the two affiliates together. The interrelationship between the two affiliates under the various agreements led the Commission to evaluate the proposals in light of the FPA section 205(b) prohibition against undue discrimination or preference.

The Commission rejected all three agreements based on affiliation and preferential pricing concerns. The Transmission Agreement was found to utilize a rate representing only a "token contribution" to Iowa Southern's fixed costs, which resulted in far less payment to Iowa Southern than what it would have received from a non-affiliate.[161] As in *TECO*, the Commission was concerned with the diversion of profits away from Iowa Southern's ratepayers to the benefit of the shareholders of Iowa Southern and Terra Comfort.[162] In addition, Iowa Southern's Energy Agreement contained no generation demand charge, yet Terra Comfort's Capacity and Energy Agreement did require the nonaffiliated purchasing utility to pay a generation demand charge which also exceeded the fixed costs of Terra Comfort's combustion turbine units.[163] Thus, Iowa Southern's power agreement was found to be underpriced to the detriment of its ratepayers and, correspondingly, Terra Comfort's power agreement was overpriced to the benefit of the shareholders of the two affiliates.

An additional potential affiliate abuse is reciprocal dealing by the seller and purchaser or their affiliates. A method of reciprocal dealing was identified

159. *TECO*, 53 F.E.R.C. ¶ 61,202, at 61,809 & n.12. On rehearing, the Commission accepted the rate proposals, as modified, on a cost basis. In contrast to situations where market-based rates are at issue, the Commission noted that it normally does not pursue the question of undue preference where cost-based rates are proposed, provided there is no evidence or claim of undue preference. *Id.* at 61,811 n.16.

160. Terra Comfort Corp., 52 F.E.R.C. ¶ 61,241, at 61,834-35 (1990).

161. *Id.* at 61,838.

162. *Id.*

163. *Id.*

in *Commonwealth*, where Commonwealth Atlantic Limited Partnership (Commonwealth) sought to sell energy and capacity to Virginia Electric Power Company (Virginia Power). An affiliate of Virginia Power was the part-owner of QF facilities in California that sold power to Southern California Edison Company (Southern California Edison). Southern California Edison was affiliated with Mission Energy Company (Mission) which, in turn, was affiliated with Commonwealth. The Commission stated:

> This sale of QF power by an affiliate of Virginia Power to an affiliate of Mission, which is a parent of Commonwealth, raises the potential for reciprocal dealing in that it is possible that Virginia Power could have agreed to pay more for power to Commonwealth (and, indirectly, to its parents, including Mission, an affiliate of Southern California Edison) in return for Southern California Edison paying more for power from the QFs in which Dominion, Virginia Power's affiliate, has an interest.[164]

No reciprocal dealing was found to exist. The QFs of Virginia Power's affiliate appeared to be paid on a similar basis as other QFs in California through the use of standard offer QF rates, which were capped at avoided cost levels and approved by the state regulatory commission.[165]

V. THE USE OF AVOIDED COSTS AND STATE AGENCY FINDINGS TO ESTABLISH JUST AND REASONABLE MARKET-BASED RATES

Together with analyses involving market prices and affiliate relationships, two additional elements often enter into determining whether market-based pricing proposals are just and reasonable. First, the Commission has looked to whether a price cap or ceiling, often based on the avoided cost of the purchasers, is appropriate.[166] For example, in *Orange and Rockland Utilities, Inc.*,[167] the Commission approved a rate cap based on a utility's avoided costs for purchasing peaking capacity and associated energy from IPPs, thus avoiding inquiry into the IPP's cost of service. The upper end of the zone of reasonableness would be the purchasing utility's avoided costs, and the lower end results from the selling IPP's ability to voluntarily decline to make the sale.[168] Second, the role that state agency findings play in the Commission's own evaluation of market-based pricing proposals has been mixed.

In *Ocean State*, formula rates were approved by the Commission with the expectation that the rates would be lower than the cost the purchasers other-

164. Commonwealth Atl. Ltd. Partnership, 51 F.E.R.C. ¶ 61,368, at 62,245 (1990).

165. *Id.* at 62,246.

166. *See, e.g.*, Doswell Ltd. Partnership, 50 F.E.R.C. ¶ 61,251 at 61,756 (1990). The Commission also, on occasion, has utilized a cap based on the seller's costs. *Id.* (citing Pacific Gas & Elec. Co., 42 F.E.R.C. ¶ 61,406 and Pacific Gas & Elec. Co., 44 F.E.R.C. ¶ 61,010 (1988).

167. Orange and Rockland Utils., Inc., 42 F.E.R.C. ¶ 61,012, at 61,028-29 (1988).

168. *Id. See also* Baltimore Gas & Elec. Co., 40 F.E.R.C. ¶ 61,059, at 61,170 (1987), where the Commission addressed a proposal for the auction of transmission capability when a varying price cap would be used, based upon the alternative cost to a bidder of acquiring power from a wide array of pool resources at Commission approved rates. The Commission found that the cap marked the upper bound of the zone of reasonableness, and that winning bids would always be less than or equal to the alternative cost of acquiring power because no purchaser would pay more than those alternative costs. The lower end of the zone would be defined by the seller's ability to reject all bids and retain, or sell, its own entitlements at rates approved by the Commission. *Id.* at 61,538.

wise would incur for alternative comparable power. The rate level was confirmed by the Commission through findings by state commissions which had calculated expected cost savings to the purchasers resulting from the Ocean State project.[169] Non-cost based rates were also approved in *Doswell* where the purchaser's avoided costs were held to be within the zone of reasonableness. The avoided costs had been set in conjunction with a QF solicitation by the purchaser, Virginia Power. The Commission received assurance from Virginia Power that rates of the seller, Doswell, an IPP, did not exceed Virginia Power's avoided costs and found that Virginia Power's avoided costs would be the same whether the generator were an IPP or QF. The purchaser's avoided cases were also "corroborated" by the state commission's use of costs relating to one of the purchaser's generating facilities to determine the purchaser's avoided cost.[170] In such circumstances, Doswell's rate would not exceed the upper end of the zone of reasonableness because the price to be paid by the purchaser would not exceed its avoided costs.

In other proceedings, the Commission has held that avoided cost pricing caps were not necessary because of the broad response to requests for power in either a formal bidding procedure or under an environment that was formed to resemble such procedures. In *Commonwealth*, the Commission found that the purchaser's avoided cost had been established through a "publicized, competitive, all-source solicitation process" which involved ninety-five responses from potential suppliers.[171] The Commission also relied on the state commission's comparison of the seller's proposal and the purchaser's self-generation option to reach the conclusion that the rate to be paid would fall under an avoided cost level.[172] To similar effect, in *Enron Power* the Commission again did not require an avoided cost-cap finding. As in *Commonwealth*, it was held that a well-publicized competitive solicitation provided an avoided cost which demonstrated that the purchaser would be no worse off than if the purchaser had purchased the power elsewhere or generated the power itself.[173]

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169. Ocean State Power, 44 F.E.R.C. ¶ 61,261, at 61,982, 61,984 (1988). In a lengthy dissent, Commissioner Trabandt questioned the use, in essence, of an "avoided cost" rate where the facility in question would not otherwise qualify under PURPA for such a rate. *Id.* at 61,986. He also faulted the majority's lack of objective consideration of other cost-based matters, and submitted that *de facto* market power existed because no other true alternatives were identified, and the sales would take place in a capacity-constrained market. *Id.* at 61,993.

170. *Doswell*, 50 F.E.R.C. ¶ 61,251, at 61,758. Commissioner Trabandt, in a separate concurring opinion, noted that the state commission reviewed the Doswell-Virginia Power contract and found that Doswell's rates, based on avoided costs, were reasonable. *Id.* at 61,761. He further stated that "fundamental comity" demanded that the Commission place "appropriate significance and weight on any relevant state commission analysis and conclusion as to the reasonableness of the IPP's rate." *Id.* at 61,762.

171. Commonwealth Atl. Ltd. Partnership, 51 F.E.R.C. ¶ 61,368, at 62,249 (1990). Commissioner Trabandt took issue with this conclusion. After noting the Commission's "aversion to any reliance on cost-based factors and determinations by state utility commissions," he opined that cost-based data was available from the state commission which would justify the seller's rate as just and reasonable. *Id.* at 62,253-54 (Trabandt, Comm'r, concurring).

172. *Id.* at n.84.

173. Enron Power Enter. Corp., 52 F.E.R.C. ¶ 61,193, at 61,712 (1990). Commissioner Trabandt, in a partial dissent, contended that the majority failed to provide a complete analysis into the competitiveness of the purchaser's solicitation. *Id.* at 61,715. He also questioned whether the evidence supported finding that the rate was below a ceiling for purposes of falling within the zone of reasonableness, particularly when the

Approvals of market-based pricing proposals also have required, in some instances, that purchasers certify that rates are not above avoided cost levels. In *Citizens* the Commission required a certification by a buyer that the market-based rate to be paid a marketer of electric power is less than or equal to the cost of alternative power. The Commission did not express great concern with the fact that the purchaser was not known ahead of time because of Citizen's status as a marketer. Rather, the Commission noted that purchases would be voluntary and the mandatory certification procedure would be sufficient to assure that the rate will fall within the zone of reasonableness.[174] An avoided cost certification also was required in *PSI* where an electric utility was granted authority to make certain sales of power at market based rates. The purchaser would be required to certify that it reviewed alternative supplies and that the price paid the selling utility is below the purchaser's "expected alternative cost of similar electric power."[175]

The Commission has shown that it will not approve transactions involving market-based pricing even where a state commission found that the proposal would be cost effective. In *TECO*, the Commission rejected filings which included market-based rates for sales between affiliates and by one of the affiliates to a non-affiliate, Seminole, despite the review of the agreements and approval of the project by the state commission.[176] The Florida commission had found that Power Service's proposal was the most cost effective means of meeting current and future generating needs.[177] However, FERC evaluated the costs of a construction option not specifically considered by the Florida commission to find a potential for self-dealing, thus exercising its "independent statutory obligation to ensure that wholesale rates are just, reasonable, and not unduly discriminatory or preferential."[178]

In *Nevada Sun-Peak*, FERC again discounted the importance of a state agency's findings. In evaluating the proposed sale to Nevada Power Company (Nevada Power) by Nevada Sun-Peak Limited Partnership (Nevada Sun-Peak), the Nevada commission determined that Nevada Power needed more capacity in the near term and concluded that the proposed rates for the transaction did not exceed the estimated costs for Nevada Power to construct similar facilities.[179] But, the FERC did not find the Nevada state commission's holdings to be adequate for satisfying the just and reasonable standard under the FPA:

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applicant, for price comparison purposes, relied on costs of a "proxy" generating facility that would not be built for seven years. *Id.* at 61,716-17.

174. Citizens Power & Light Corp., 48 F.E.R.C. ¶ 61,210, at 61,779 (1989). In a reluctant concurrence with the order, Commissioner Trabandt observed that because the seller was a marketer and the authorization related to yet-to-be negotiated transactions, the Commission was unable to determine the extent of market power the seller may have for each transaction. *Id.* at 61,783. He also questioned the reliability of the buyer's certification that the rate will not exceed its avoided cost because the Commission would not have "the foggiest idea of how the price of alternate electricity is defined, or calculated. . . ." *Id.* at 61,784.

175. Pub. Serv. Co. of Ind., 51 F.E.R.C. ¶ 61,367, at 62,227 (1990).

176. TECO Power Servs. Corp., 52 F.E.R.C. ¶ 61,191, at 61,693-94 (1990).

177. *See* TECO Power Servs. Corp., 53 F.E.R.C. ¶ 61,202, at 61,808 (1990).

178. *Id.* at 61,811; *see also*, 52 F.E.R.C. ¶ 61,191, at 61,698-99.

179. Nevada Sun-Peak Ltd. Partnership, 54 F.E.R.C. ¶ 61,264, at 61,768 (1991).

> The Nevada Commission's review focused on Nevada Power's need for capacity and on a cost comparison of Sun-Peak power to a single alternative, self-construction. A finding that Sun-Peak's rates are less than the cost of self-construction is not a sufficient basis to determine that the rates are just and reasonable under the Federal Power Act. *The Commission has required that entities selling capacity at market-based rates demonstrate that the market, not the buyer's avoided cost, disciplined the rate.* This demonstration was not made during the Nevada Commission's proceeding or in Sun-Peak's submittal here.[180]

This decision was the subject of dissenting opinions by Commissioner Trabrandt, who showed that the FERC has in the past acted in a relatively consistent manner with state commissions on the issue of power procurement,[181] and by Commissioner Moler, who stated that the majority was "just plain wrong" to imply that the purchaser's avoided cost does not discipline the rate for such sales.[182]

While the seller's rates in *Nevada Sun-Peak* ultimately were approved on a cost basis in a subsequent order,[183] the Commission's reasoning behind its initial rejection of the seller's rates highlights the potential for inconsistent and possibly arbitrary action when attempting to justify market-based rates through an avoided cost comparison. The majority's reasoning that the market and not the avoided costs "disciplined the rate" is at variance with prior orders where price caps or ceilings based upon avoided costs have been an integral part in establishing just and reasonable rates. Moreover, the finding that self-generation, by itself, should not be considered as a viable alternative for FPA purposes appears less than consistent with prior decisions.[184] Also, the Commission's disregard in *Nevada Sun-Peak* of the state agency determinations adds to a pattern that may create uncertainty. While the Commission has not given full credit to state agency findings in proceedings involving market-based rates (such as *TECO*), it has relied on state determinations and oversight in other proceedings to help justify acceptance of such rates. The Commission's ultimate approval of Nevada Sun-Peak's rates on a cost basis avoided answering these concerns.

VI. OTHER MONITORING DEVICES

The Court in *Farmers Union* found as a "fundamental flaw" the lack of a

180. *Id.* at 61,770-71 (emphasis added) (footnote omitted).

181. *Id.* at 61,773-74 (Trabandt, Comm'r, dissenting). Shortly after the Commission's acceptance of Nevada Sun-Peak's rates on a cost basis, the Commission found the New Jersey commission's approval of purchase power agreements relevant to determine whether there existed a lack of market power in generation. *See* Cleveland Elec. Illuminating Co., 55 F.E.R.C. ¶ 61,172, at 61,553 (1990).

182. *Id.* at 61,779 n.4 (Moler, Comm'r, dissenting). Commissioner Moler believed that the process used by the Nevada commission insured that all feasible alternatives had been explored. *Id.* at 61,778.

183. Nevada Sun-Peak Ltd. Partnership, 55 F.E.R.C. ¶ 61,058, at 61,162 (1991). As a result of Nevada Sun-Peak submitting data to justify its rates on a cost basis, arguments raised on rehearing by Nevada Sun-Peak and the Nevada commission were not addressed. Commissioner Trabandt observed that such action rendered moot all legal consequences of the Commission's first order. *Id.* at 61,164 (Trabandt, Comm'r, concurring).

184. As previously discussed, in *Enron Power* and *Commonwealth* the Commission found that the rates achieved through a competitive process would leave the purchaser no worse off than if it generated the power itself, or purchased it from another service. *See* Enron Power Enter. Corp., 52 F.E.R.C. ¶ 61,193, at 61,712 (1990); Commonwealth Atl. Ltd. Partnership, 51 F.E.R.C. ¶ 61,368, at 62,249 (1990).

monitor to check whether competition would force market-based prices into the statutory zone of reasonableness for rates.[185] As discussed in the preceding section, in various proceedings the Commission has imposed or identified the existence of a price cap or ceiling to prevent excessive rates. This acts as a monitor to check the ability of rates to move beyond the zone of reasonableness. As a further check, however, the Commission has either directed that monitoring or other conditions be undertaken or has indicated that a relevant pricing mechanism approved by the Commission will be subject to change only after further review in the future.

Where a seller's rate is a formula rate, the formula cannot be changed without further filings by the seller with the Commission. In those instances, no monitoring device is necessary because the Commission will be able to assess, in a *de novo* review, whether the seller has acquired or is exercising market power over the purchaser.[186] In contrast, in *PSI*, periodic market analyses reports to be filed by the seller, and the ability of potential customers to intervene in proceedings or file complaints with the Commission would serve a monitoring function.[187] In *Citizens Power & Light*, the Commission approved a marketer's flexible pricing provision on the condition that neither the marketer nor an affiliate own any transmission facilities and that the marketer not affiliate with an entity which has a franchised service area. The marketer also was required to make informational filings with the Commission respecting each of its future purchase and sales contracts, for the continued monitoring of market power.[188]

VII. CONCLUSION

Changes in the electric industry and the need for new supply sources have given rise to transactions which use market-based pricing concepts. In many instances, the number of parties that bid to provide resources in response to solicitations by utilities demonstrates that numerous potential suppliers exist. Market-based pricing seeks to take advantage of this situation by allowing competitive market forces to set rates.

In these circumstances, the Commission, in implementing and carrying out its responsibilities, should seek to balance two interests. On one hand, in allowing a competitive process to establish rates based on what the market will bear, it must act consistently with its statutory obligations and provide that rates are just and reasonable, serve a legitimate statutory objective, and are within a zone of reasonableness. On the other hand, the Commission must see

185. Farmers Union Cent. Exch. Inc., v. F.E.R.C., 734 F.2d 1486, 1509, cert. denied, 469 U.S. 1034 (1984).

186. *See, e.g.*, Dartmouth Power Assocs. Ltd. Partnership, 53 F.E.R.C. ¶ 61,117, at 61,360 (1990); *Enron*, 52 F.E.R.C. ¶ 61,193, at 61,711 (1990). *See also Commonwealth*, 51 F.E.R.C. ¶ 61,368, at 62,250 (1990).

187. Pub. Serv. Co. of Ind., 51 F.E.R.C. ¶ 61,367, at 62,209, 62,226 (1990). *But see* Commissioner Trabandt's concurring opinion in Citizens Power & Light Corp., 48 F.E.R.C. ¶ 61,210, at 61,784 (1989) where similar reasoning was seen unrealistic, especially where the customers of the purchaser, and competitors, may not receive notice of the sale.

188. *Citizens*, 48 F.E.R.C. ¶ 61,210, at 61,778.

that such rates do not result from a process where one party (either by itself or through affiliation) possesses market power to the extent that it can exclude competitors and distort the market. Implementation of general standards to be followed in evaluating proposals that contain market-based pricing will provide some guidance to parties that must receive Commission approval. Indeed, the Commission's public conference on electricity issues foreshadows the potential for specific regulations to address such matters as market-based rates for sales of wholesale power by new generation sources, the concerns that exist when affiliate relationships are involved in such transactions, and the role of transmission access to mitigate market power.[189] The Commission should act promptly to establish such standards based upon its past decisions in this area. Nevertheless, many market-based rate proposals involve unique and complex factual situations which do not lend themselves to generic rules, particularly where questions of market power and affiliate relationships are involved. The Commission must be careful to leave avenues open to evaluate these proposals, especially as existing and new competitors in the market gain experience and seek assurance that the playing field is kept level.

189. *See* Address by Martin L. Allday, Chairman, Federal Energy Regulatory Commission, to the American Bar Association, Atlanta, Ga. (Aug. 13, 1991).