A NEW FERC POLICY FOR ELECTRIC UTILITY MERGERS?

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I. Introduction

The predictions of Wall Street analysts have finally come true: the electric utility industry is now undergoing a fairly significant consolidation trend. At the Federal Energy Regulatory Commission (FERC or Commission), this means a steady diet of merger applications over the next several years. In the midst of this increased activity, however, the Commission finds itself without a clearly articulated merger policy. There is significant confusion and debate regarding the viability of the Commission's current approach to the two key issues in merger cases: the effect on competition and the effect on rates.[1] The Commissioners have acknowledged this and have responded by issuing a notice of inquiry requesting comment on the FERC's merger policy.[2] The only question seems to be when, not whether, the current policy will be revised.

At the outset, there is some confusion regarding what needs to be "reformed." It is not clear that any of the current advocates of policy reform are truly dissatisfied with the handling of prior FERC merger cases. For example, while many argue that the FERC is too preoccupied with remedying transmission market power and gives short shrift to claims of generation market power, in prior merger cases there were very few (if any) arguing that the merged company would dominate generation markets once open access to its transmission system had been assured.[3] Given the paucity of any such objections, it is hardly fair to criticize the FERC for not having studied the matter in more detail.

Whatever the case, the goal, on a going forward basis, should be to develop coherent substantive standards for merger cases and reasonable

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1. *See Washington Water Power Co. and Sierra Pac. Power Co.*, 73 F.E.R.C. ¶ 61,218 (1995) (criticizing applicants for not alleging certain merger benefits); *Midwest Power Sys., Inc. and Iowa-Ill. Gas and Elec. Co.*, 71 F.E.R.C. ¶ 61,386 (1995) (Massey and Hoecker, Comm'rs, concurring) (suggesting reconsideration of the manner in which competition issues are addressed). Major industry segments also have called for policy reform. *See* Joint Petition of American Public Power Association and the National Rural Electric Cooperative Association for a Rulemaking Proceeding to Revise the Commission's Standards Applicable to the Merger of Public Utilities Under Section 203 of the Federal Power Act, Docket No. PL96-1-000.

2. *See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act*, Docket No. RM96-6-000, (Jan. 31, 1996).

3. For example, in Opinion No. 364, *Northeast Utils. Serv. Co. (Re: Public Serv. Co. of N.H.)*, 56 F.E.R.C. ¶ 61,269 (1991), the Commission found that the merged company would possess 65% of the uncommitted generating capacity in the relevant geographic market, but that its market power would "dissipate" as its surplus capacity diminished. *Id.* at 62,007. On rehearing, the Commission was not asked to reconsider this finding. Opinion No. 364-A, 58 F.E.R.C. ¶ 61,070 (1992).

procedures by which they can be processed. Several proposals, both substantive and procedural, are contained in this article. They are summarized below.

First, the Commission should adopt more detailed standards for analyzing a merger's effect on competition. The FERC's treatment of competition issues in past mergers and market-based rate cases has been fairly consistent (which is a good thing), but these precedents have their limits. In some regions of the country, market reform will be so substantial (*e.g.*, adoption of a "Poolco") that the current methodology for defining markets and calculating market shares may prove insufficient. Other aspects of the FERC's merger precedents seem anachronistic, such as determining whether a merger negatively impacts transmission "markets." Part II of this article discusses the aspects of the FERC's current market power analysis that deserve reevaluation in light of the changes underway in bulk power markets.

Second, the Commission should, with very few exceptions, eliminate its analysis of the cost and rate impacts of a proposed merger. The original justification for evaluating merger benefits and costs—to determine whether a merger would burden captive ratepayers with higher rates—is disappearing. The wholesale market will soon be fully competitive and wholesale customers will be able to protect themselves by switching power suppliers if a merger increases costs and renders the merged company noncompetitive. Perhaps the only significant lingering question will be whether the FERC should conduct a cost-benefit analysis as a means of protecting captive retail ratepayers. I have argued previously that the FERC should not be drawn into this area absent exceptional circumstances.[4]

Third, the Commission should substantially revise the procedures by which it reviews utility mergers. The defects in the current process are many. There are no filing requirements for the most critical issues, including the effect of the merger on competition. There is no established process, such as the deficiency letter, by which the Commission Staff can request additional information from the applicants. There is great uncertainty with regard to whether (and when) a case will be set for hearing. There is great uncertainty as to how long the merger review process will take. The Commission should provide greater guidance regarding the information that merging applicants must supply and the procedures (and timing) by which their applications will be processed. Procedures really do matter, especially in merger cases, which are time-sensitive and factually complex.

Finally, if there is to be policy reform, the Commission has the choice of whether to pursue reform in a generic proceeding, such as a rulemaking, or to implement reform in the context of deciding individual cases. While the Commission has issued a notice of inquiry regarding merger policy, the

4. John S. Moot, *The Changing Focus of Electric Utility Merger Proceedings*, 15 ENERGY L.J. 1, 15-16 (1994).

Commission has not indicated whether that proceeding will result in the issuance of generic rules or whether, instead, the proceeding will serve as an information-gathering tool, with policy reform (if any) to be implemented in individual cases. Part V of this article suggests that some aspects of policy reform can be accomplished in an individual case, while others might be more appropriately handled in a rulemaking.

II. The Effect on Competition

A. *Overview of the Current Standards*

The courts have held that "the Commission has . . . an obligation under the Federal Power Act to consider antitrust policies in determining whether a merger satisfies section 203's 'public interest' standard."[5] This does not mean that the Commission is "strictly bound by . . . the antitrust laws."[6] Rather, the Commission will "weigh" antitrust effects "along with other important public interest considerations."[7]

In prior merger and market-based rate cases, the Commission has constructed a fairly consistent methodology for addressing market power issues. The FERC generally considers non-firm energy, short-run firm capacity, and transmission to be the relevant product markets.[8] The FERC analyzes each wholesale customer affected by a transaction as a separate "destination market."[9] The FERC includes in the geographic market sellers that can access the destination market by paying a maximum of two

5. Kansas City Power & Light Co. v. FPC, 554 F.2d 1178, 1184 (D.C. Cir. 1977). *See also Commonwealth Edison Co.*, 36 F.P.C. 927, 941 (1966) ("There is a legitimate public interest in the degree of concentration of economic power in American industries and, notwithstanding the safeguard of regulation, even in the electric utility industry."). *Cf.* Gulf States Utils. Co. v. FPC, 411 U.S. 747, 760 (1973) (Commission must consider antitrust allegations in determining whether a securities issuance under section 204 is "compatible with the public interest").

6. *Utah Power & Light Co.*, 45 F.E.R.C. ¶ 61,095, at 61,283 (1988).

7. *Id.*

8. *El Paso Elec. Co. and Central & S.W. Servs., Inc.*, 68 F.E.R.C. ¶ 61,181, at 61,913 (1994) (energy, short-run capacity and transmission capacity); *Entergy Servs., Inc. and Gulf States Utils. Co.*, 62 F.E.R.C. ¶ 61,073, at 61,380 (energy and short-run capacity); *Northeast Utils. Serv. Co. (re: Public Serv. Co. of N.H.)*, 56 F.E.R.C. at 62,001-04 (short-run capacity, long-run capacity, and transmission service).

9. *See generally Entergy Servs., Inc. and Gulf States Util. Co.*, 62 F.E.R.C. ¶ 61,073 (1993) (app. A) (identifying market shares for each destination market); *Louisville Gas & Elec. Co.*, 62 F.E.R.C. ¶ 61,016 (1993) (explaining destination market analysis).

open-access transmission charges.[10] The FERC considers market shares of less than thirty percent in these markets to be generally nonproblematic.[11]

The FERC has adopted this methodology without explicit reliance on the Department of Justice (DOJ) and Federal Trade Commission (FTC) Merger Guidelines.[12] However, the FERC has not suggested that applying the Merger Guidelines to a utility merger case would be inappropriate and, indeed, the Commission in merger cases regularly calculates Herfindahl-Hirschman Indices (HHIs), the principal analytic tool of the Merger Guidelines for measuring market concentration.[13]

B. *The Need for More Detailed Guidelines*

The FERC's current methodology has served it fairly well in prior cases and many aspects of the analysis should be retained, as discussed in more detail below. There are two basic limitations of this methodology, however. First, the methodology has been applied, and is most useful, as a "screening tool" to separate problem mergers (or market-based rate

10. The two open access charges are (i) the seller's transmission rate (if any), and (ii) the intermediate utility's transmission rate. See *Southwestern Pub. Serv. Co.*, 72 F.E.R.C. ¶ 61,208 (1995) (including all sellers that could reach destination market by paying SPS wheeling rate plus their own rate, if any); *Louisville Gas & Elec. Co.*, 62 F.E.R.C. at 61,153 (including all sellers that could access market by paying LG&E's wheeling rate plus their own rate, if any). *See also Public Serv. Co. of Ind.*, 51 F.E.R.C. ¶ 61,367, at 62,206 (1990) ("The geographic market for each eligible customer is defined by the customer's ability to obtain transmission to connect it to relevant generation resources."). The FERC includes in the market sellers that are "two wheels" away *only if* the intermediate wheel is over an open access system. Until recently, open access was the exception, not the rule, and thus in many cases the FERC only included in the market utilities directly interconnected with the destination market. *See Entergy Servs., Inc.*, 60 F.E.R.C. ¶ 61,168, at 61,620 (1992) ("The Commission purposefully defined the geographic markets in the narrowest fashion possible by considering only those utilities directly connected to a potential buyer as Entergy's competitors. If Entergy has no market power under this conservative analysis, a more extensive analysis is not needed."). In *Kansas City Power & Light Co.*, 67 F.E.R.C. ¶ 61,183 (1994), the Commission did not include sellers reachable through transmission systems that had not yet been required to file "comparable" transmission service tariffs.

11. *Entergy Servs., Inc. and Gulf States Utils. Co.*, 62 F.E.R.C. at 61,374 (27% market share in uncommitted generation capacity not impediment to approval of merger); *Southern Co. Servs., Inc.*, 72 F.E.R.C. ¶ 61,324 (1995) (26% share of "installed capacity" not impediment to approval of market based rates); *Southwestern Pub. Serv. Co.*, 72 F.E.R.C. ¶ 61,208 (1995) (25% market share in "installed capacity" not impediment to approval of market-based rates); *Public Serv. Co. of Ind.*, 51 F.E.R.C. at 62,209 (less than 20% market share in all markets).

12. *Public Serv. Co. of Ind.*, 51 F.E.R.C. at 62,205 (there are "various methods of analyzing market power" and "we do not believe that any one type of evidence is sufficient for this analysis.").

13. *See El Paso Elec. Co. and Central & S.W. Servs., Inc.*, 68 F.E.R.C. at 61,913 n.122 (calculating HHIs); *Entergy Servs., Inc. and Gulf States Utils. Co.*, 62 F.E.R.C. at 61,380 (app. B) (calculating HHIs); *Utah Power & Light Co., PacifiCorp and PC/UP&L Merging Corp.*, 45 F.E.R.C. ¶ 61,095, at 61,286 n.127 (1988) (calculating HHIs). In an oil pipeline case, the FERC stated that "[f]or measuring market concentration, we conclude that a proper screening device is an HHI." *Buckeye Pipe Line Co.*, 53 F.E.R.C. ¶ 61,473, at 62,667 (1990). Apparently lacking the necessary policy guidance, however, the administrative law judges in two merger cases declined to use HHIs in assessing the merger's effect on competition. *See Southern Cal. Edison Co. and San Diego Gas & Elec. Co.*, 53 F.E.R.C. ¶ 63,014, at 65,107 n.34 (1990) ("[t]he HHI is of no use to the Commission because the Commission is not challenging the merger"); *Northeast Utils. Serv. Co. (re: Public Serv. Co. of N.H.)*, 53 F.E.R.C. ¶ 63,020, at 65,219 (1990) ("An examination of the disputed numerical devices would serve no useful purpose in the circumstances of this case").

requests) from nonproblematic ones. The FERC has not, however, developed standards for analyzing mergers that fail the market screening tests. The failure to pass a market screen does not mean that a merger will harm competition, but rather that a more detailed assessment of the market is necessary.[14] More guidance regarding the nature of such an inquiry is necessary.

Second, the current methodology relies on the contract path, postage stamp rate convention for defining the options available to each customer. Under alternative market institutions, however, particularly a "Poolco" structure, these assumptions may no longer apply.[15] Thus, there is a need for more flexible analytic tools for judging mergers that occur in a variety of market structures.

C. *Adopting the DOJ/FTC Merger Guidelines*

It is suggested that the need for a broader analytic framework for analyzing utility mergers can be satisfied by adopting the DOJ/FTC Merger Guidelines. Adopting the Merger Guidelines will provide clearer criteria by which to evaluate competitive issues and will provide sufficient flexibility for analyzing mergers arising under a variety of market structures. The benefits of adopting the Merger Guidelines are several, as discussed below.

First, adopting the Merger Guidelines will provide valuable clarity to all participants, especially merging companies, thereby reducing litigation and transaction costs. In deciding whether or not to merge, electric utilities routinely assess whether the contemplated transaction will be challenged by the Federal Government on competitive grounds. They cannot do so effectively, however, without clear guidance from all arms of the Government, including the FERC.[16]

Second, adopting the Merger Guidelines will provide the FERC with significant flexibility in analyzing individual cases. The Merger Guidelines are designed to apply to a broad range of industries and products, from diapers to aircraft engines. They can thus be adapted to the electric industry with due recognition of its "functional" characteristics.[17] This flexibility

14. U.S. Dep't. of Justice Horizontal Merger Guidelines, 57 Fed. Reg. 41,552, *reprinted in* 4 Trade Reg. Rep. (CCH) ¶ 13,104, § 2.0 (1992) [hereinafter *Merger Guidelines*] ("[M]arket share and concentration data provide only the starting point for analyzing the competitive impact of a merger."); *Public Serv. Co. of Ind.*, 51 F.E.R.C. at 62,205 ("[W]e will not rely on any mechanical market share analysis to determine whether a firm has market power").

15. In today's market, energy is exchanged between utilities operating separate control areas, each charging its own transmission rate. In a pure Poolco market, energy is sold by each utility into a common pool and delivered to all customers within that pool at the marginal cost of transmission service.

16. The Securities and Exchange Commission (SEC) also has authority to review competitive issues, but ordinarily will defer to the FERC's handling of the matter. City of Holyoke Gas & Elec. Dep't v. SEC, 972 F.2d 358 (D.C. Cir. 1992).

17. Brown Shoe Co. v. United States, 370 U.S. 294, 321-22 (1962) (a merger must be "functionally viewed in the context of its particular industry"); *Entergy Servs., Inc. and Gulf States Utils. Co.*, 62 F.E.R.C. ¶ 61,073, at 61,375 (1993).

will be especially important given the different market structures that will develop in the future.

Third, adopting the Merger Guidelines will promote consistency of merger review within the Federal Government.[18] This not only will reduce potential conflicts between agencies, but may provide the DOJ and FTC a basis for deferring to the FERC in most merger cases or, where the DOJ or FTC do have significant concerns, participating as an intervenor at the FERC.[19]

D. *Applying the Merger Guidelines*

Will adopting the Merger Guidelines put an end to disputes over competition issues in merger cases? The answer is no. The Merger Guidelines provide a solid analytic foundation for defining markets and assessing the degree to which market power can be exercised in a given market. The work of applying these analytic tools to the facts of a particular case, however, will often prove controversial. The following is a discussion of some of the recurring factual questions that likely will arise in future utility merger cases.

1. Market Definition

a. Product Markets

The Commission has traditionally identified three product markets that should be examined in merger and market-based rate cases: short-run capacity, nonfirm energy, and transmission services. A fourth market, long-run capacity, is no longer considered because of the ease of entry into that market.[20] Which of these product markets will be relevant in future cases? A few suggestions are offered below.

(1) Short-Run Capacity

Short-run capacity[21] will likely continue to be a relevant market in the near term. Short-run capacity (and "capacity" in general) is a necessary

18. *See* Department of Justice/Federal Trade Comm'n, Press Release, Statement Accompanying Release of Revised Merger Guidelines and 1992 Horizontal Merger Guidelines at 1 (Apr. 2, 1992) ("As a principle of good government, joint guidelines are a major step forward. Where, as here, two agencies have concurrent enforcement responsibilities, the standards to be applied should not depend on which agency is analyzing a particular merger.").

19. This occurred in *Southern Cal. Edison Co. and San Diego Gas & Elec. Co.*, 53 F.E.R.C. ¶ 63,014 (1990).

20. *Kansas City Power & Light Co.*, 67 F.E.R.C. ¶ 61,183, at 61,557 (1994) ("[I]n light of industry and statutory changes which allow ease of market entry, we therefore will no longer require rate applicants to submit evidence of generation dominance in long-run bulk power markets."); *see also Merger Guidelines*, *supra* note 14, § 3.0 ("A merger is not likely to create or enhance market power or to facilitate its exercise, if entry into the market is so easy that market participants, after the merger, either collectively or unilaterally could not profitably maintain a price increase above premerger levels.").

21. Short-run capacity is a product that is purchased to meet unexpected supply shortages or to meet future load growth in a manner that avoids the commitments and expense associated with building

product in an environment where utilities are required to maintain system reliability by carrying specified generating reserves in excess of their projected peak demand.[22] So long as these reserve requirements apply, short-run capacity will be a product that is used to meet them.

In the future, however, "capacity" may vanish as a separate product in some regions of the country. For example, in a pure Poolco market,[23] price will dictate the amount of generating capacity that is built, not internally (or externally) imposed reserve margins.[24] Over time, the price for energy will approach the long-run marginal cost of building new generating capacity, which should provide sufficient incentives to construct new generation to meet load growth (or replace retired units). This is not unlike competitive markets, such as oil, where customers generally do not buy "firm" or "nonfirm" gasoline; they simply purchase it at a price that, over time, is sufficient to encourage exploration and development of additional oil reserves.

(2) Nonfirm Energy

Nonfirm energy is bought by utilities to reduce their marginal cost of production.[25] There is little doubt that nonfirm energy (or simply "energy") will continue to be a relevant product market in future merger cases. Trade in energy markets will, if anything, intensify given the increased availability of transmission service, the elimination of inefficiencies in nonfirm transmission pricing,[26] the proliferation of power market-

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a new generating unit or entering into a long-term power purchase agreement. The term "short-term" refers to the fact that it is capacity available from existing supplies, rather than from newly constructed generation, which generally has a lead time of two years or more. The FERC considers short-run capacity a separate market from long-run capacity because "purchasing a 20-year commitment to meet power needs that exist for a few days or years would be prohibitively expensive." *Northeast Utils. Serv. Co.*, 56 F.E.R.C. ¶ 61,269, at 62,003 (1991).

22. These reserve requirements can be self-imposed, imposed by a state regulator, or imposed by a regional body, such as a power pool. The most common planning criterion is that a utility experience a "loss of load probability" of not more than one day in ten years. Using a computer model of projected load and potential generation and transmission outages, the utility will estimate the amount of generation reserves required to meet this criterion.

23. Some pooling proposals may include major aspects of a pure Poolco structure, such as spot energy prices and marginal cost pricing of transmission usage, but may nevertheless retain a minimum generating reserve requirement for each load-serving entity in the pool. *See, e.g., Supplemental Comments of the Supporting PJM Companies for Technical Conference on Comparability for Power Pools*, Docket No. RM95-8-000 (Nov. 30, 1995).

24. There may, however, be financial instruments that apportion the economic risk of curtailments. There may also be differences in the degree of interruptibility of various customers, which affects the prices they pay.

25. For example, a utility that could produce its next unit of energy at 15 mills/kwh will choose, instead, to purchase energy from another utility at 13 mills/kwh, if available. Today, energy products vary in their firmness and their price. The following are common examples of energy products that vary in firmness and price: economy energy, nondisplacement energy, short-term power, term power and firm energy.

26. Traditionally, nonfirm transmission service has been priced on an embedded cost basis, with the utility being permitted to charge any rate "up to" its firm transmission rate. *See, e.g.*, Notice of

ers, and the increased pressure on utilities to reduce their operating costs. The problem for the FERC will be *how* to define energy markets, not *whether* to study them. One key definitional issue will be whether the FERC should compute market shares for each utility using aggregate, yearly market data or analyze each hour of the year (or group of hours, such as low load, intermediate load and peak load periods) as a separate product submarket. This debate already is occurring in a pending case.[27]

(3) Transmission

The Commission's traditional policy has been to treat transmission capacity as a product market that is separate from the market for bulk power. In *Utah Power & Light Co.*, the Commission stated that "transmission is a separate product market from the bulk power market since it can be sold separately and one product cannot be substituted for the other."[28] The same rationale has been repeated in subsequent cases.[29]

The Commission's decision to treat transmission as a separate product market should be reexamined. The premise that one product (bulk power) cannot be substituted for the other (transmission) is, in many instances, incorrect. The decision to buy long-term firm capacity from a remote resource using transmission service often *is* interchangeable with the decision to locate generating capacity (*e.g.*, building a peaking unit) locally.[30] While there may be instances where an argument can be made that a particular transmission corridor provides access to unique resources for which there are no good substitutes, that hardly justifies a presumption that transmission service is a relevant product market in most (or all) cases.

Even more importantly, it is unclear why the Commission would have a policy interest in defining transmission as a relevant product market.

Proposed Rulemaking, IV F.E.R.C. STATS. & REGS. ¶ 33,514, at 33,149 (1995) [hereinafter NOPR]; *Public Serv. Co. of Ind.*, 51 F.E.R.C. ¶ 61,367, at 62,199 (1990). More recently, power marketers and some utilities have been urging the FERC to set nonfirm transmission rates at or close to short-run marginal costs (i.e., transmission losses and congestion costs) to increase the efficiency of short-term bulk power markets.

27. In the pending Wisconsin Energy Company/Northern States Power Company merger case, some intervenors have argued that the merged company will dominate energy markets at certain load periods. *See Wisconsin Energy Co. and Northern States Power Co.*, No. EC95-16-000, 1996 WL 38466 (Jan. 31, 1996) (to be reported at 74 F.E.R.C. ¶ 61,069 (1996)).

28. 45 F.E.R.C. ¶ 61,095, at 61,284 (1988).

29. *See Northeast Utils. Serv. Co. (Re: Public Serv. Co. of N.H.)*, 56 F.E.R.C. ¶ 61,269, at 62,002 (1991) ("Transmission services within the New England region are relevant products because they can be traded separately and because, for many buyers and all sellers, there are no substitutes for these services."); *El Paso Elec. Co. and Central & S.W. Servs., Inc.*, 68 F.E.R.C. ¶ 61,181, at 61,914 (1994) ("We have also evaluated the merger's effects on transmission market power as it relates to the increased ability of the merged company to withhold transmission services along important interregional transmission corridors.").

30. In a post-open access era, the considerations relevant to the location of new generation should be primarily ones of cost (*e.g.*, relative location to fuel inputs) and transmission capacity, not the availability of open access transmission service.

Transmission service is a monopoly service in the view of the Commission.[31] If that is the case, should there be a concern as to whether a merger lessens "competition" in that market? For example, is it the Commission's intention to encourage transmission providers with parallel "contract paths" to compete to provide service at discounted prices, even though neither of them can affect actual flows? From all indications, the answer is no.[32]

Moreover, any desired competition in transmission services will likely be provided by the resale market.[33] As utilities' requirements customers begin to convert to transmission-only service, they will have transmission entitlements of their own that can be resold, during certain hours, to third parties. This competition will tend to drive transmission prices toward marginal costs, at least in short-term markets. Even apart from competition in the resale market, the Commission can adopt transmission pricing policies that foster short-term efficiencies that are similar to those attainable in a competitive market.[34]

Finally, the Commission should not confuse concerns regarding operational manipulation of a transmission system with the issue of whether transmission should continue to be defined as a separate product market in merger cases. In a recent case, the FERC expressed "[concerns] about the possibility that the combination of . . . transmission constraints and strategically located generation facilities owned by the wholesale seller may result

31. NOPR, *supra* note 26, at 33,070 ("[T]ransmission remains and is expected to remain a natural monopoly"). "The monopoly characteristic exists in part because entry into the transmission market is restricted or difficult. In addition, as unit costs are less for larger lines and networks, transmission facilities still exhibit scale economies." NOPR, *supra* note 26, at 33,070.

32.

> [E]ffective competition among owners of parallel transmission lines is unlikely, and often impossible, with existing practices and technology. . . . With two electric systems providing parallel contract paths, a share of the actual power flows would occur on each system according to the physical characteristics of the system. Thus, each of the two transmission service providers would have the incentive to underbid the other because the winner would receive all of the transmission revenues, but only incur a fraction of the costs. The loser, on the other hand, would incur the remaining costs, but would receive no revenues. NOPR, *supra* note 26, at 33,070.

33. *See* NOPR, *supra* note 26, at 33,088 ("[C]apacity reassignment, combined with assured access to firm transmission service, reduces the transmission provider's market power by enabling transmission customers to compete with the owner to some extent in the firm transmission market."); *Kansas City Power & Light Co.*, 72 F.E.R.C. ¶ 61,218 (1995) (approving proposal to permit transmission customers to resell firm transmission service at the higher of their embedded or opportunity costs).

34. Many have urged the FERC to adopt transmission pricing rules that increase the efficiency of short-term markets, such as charging short-run marginal costs for hourly transmission usage, with fixed costs being allocated on the basis of relative contribution to peak demand. While this is the way in which transmission service *within* a given utility system generally is priced today, advocates of pricing reform have urged the FERC to adopt such policies on a regional basis and eliminate rate pancaking *between* utility systems.

in market power in more localized markets."[35] This concern is relevant to (i) the need to consider transmission constraints in defining geographic markets for bulk power, and (ii) the potential need for independent operational control of the transmission system, such as through an "independent system operator."[36] The concern is not relevant to the question of whether transmission service should be defined as a separate product market and whether a lessening of "competition" in that market would provide a basis for conditioning or rejecting a merger.

In sum, it is unclear what policy purpose is served by continuing to analyze transmission as a separate product market in merger cases.

b. Geographic Markets

The customary methodology for defining geographic markets in merger and market-based rate cases is to treat each wholesale customer as a separate market—*i.e.*, a "destination market."[37] The FERC has suggested that such a destination market analysis is used principally as a screening tool for identifying cases where a more detailed analysis is (or is not) necessary.[38] Indeed, in the two merger cases where competition issues were set for hearing and the Commission addressed market definition in its final opinion, the Commission defined markets on a regional basis, not a customer-specific (destination market) basis.[39] In the future, the use of a destination market analysis for anything other than a screening tool may prove controversial.[40]

Other controversial issues will include the influence of transmission rates and transmission constraints on the size of geographic markets. As to transmission rates, the FERC's current methodology includes in the market

35. *Wisconsin Elec. Power Co. and Northern States Power Co.*, No. EC95-16-000, 1996 WL 38466, at *7 (Jan. 31, 1996) (to be published at 74 F.E.R.C. ¶ 61,069 (1996)).

36. *See* FERC Technical Conference on Independent System Operators, Docket No. RM95-8-000 (Jan. 24, 1996).

37. "The geographic market for each eligible customer is defined by the customer's ability to obtain transmission to connect it to relevant generation resources." *Public Serv. Co. of Ind.*, 51 F.E.R.C. ¶ 61,367, at 62,206 (1990). *See also supra* note 9.

38. *Louisville Gas & Elec. Co.*, 62 F.E.R.C. ¶ 61,016, at 61,145 (1993) ("[If the applicant] has no market power in these geographic markets, it is unlikely to have market power in broader geographic markets, like [regional reliability councils].").

39. *Northeast Utils. Serv. Co. (re: Public Serv. Co. of N.H.)*, 56 F.E.R.C. at 61,999-62,001 (relevant geographic market is NEPOOL, with Eastern REMVEC, Vermont, and Maine relevant geographic submarkets); *Utah Power & Light Co. and PacifiCorp*, 45 F.E.R.C. at 61,284 (relevant geographic market is WSCC).

40. The problem with defining each customer as a separate geographic market can be illustrated with an example. Assume that two local grocery stores merge, leaving a particular neighborhood with only one grocery store. Assume there is one customer in that neighborhood that is afraid to drive and of public transportation. This customer will only shop at a store within walking distance. Post-merger, there is now only one store that can compete for that customer's business. Does this mean that the merger harms competition in that customer-specific destination market? Yes, but does that mean the merger should be disapproved? No.

firms that can access the destination market by paying two wheeling charges (the seller's own wheeling rate, plus one additional wheeling rate).[41] Given that utilities are slowly moving away from embedded cost, postage stamp rates for transmission service, however, the FERC's current format for geographic market definition may prove too conservative (or too liberal) in a given case. For example, to the extent marginal cost pricing is adopted for nonfirm transmission service, transmission rates will be less of a limiting factor and the FERC's current approach may prove too conservative. Conversely, to the extent the applicable transmission rates are unusually high (and not subject to discounting), a "two-wheel" assumption may prove unrealistic.[42]

Transmission constraints also can be an important factor in geographic market definition.[43] Transmission constraints limit the quantity of power that can serve a given market from remote sources. The task in a merger case will be to estimate the level and frequency of a given constraint, not an easy assignment.[44] Because of the technical nature of the issue, requiring applicants to submit data on any significant transmission constraints would expedite the process,[45] whether it be a paper hearing or a trial-type hearing.[46]

2. Screening Tools and Hearings

The purpose of performing a market screening analysis is to separate the routine cases from those that require a more detailed inquiry. In designing a market screening analysis for section 203 cases, a balance must be achieved between developing an adequate record, achieving a reasonable degree of expedition, and allowing interested parties the ability to verify the results of the market analysis. The FERC cannot conduct lengthy evidentiary hearings on every merger case and thus needs simplified screening tools to determine which cases merit a closer look. The data

41. *See supra* note 10.

42. To date, the FERC has not, however, expressed a concern regarding the effect of transmission rates on its market power analysis. *See American Elec. Power Serv. Corp.*, 72 F.E.R.C. ¶ 61,287, at 62,238 n.9 (1995) ("[B]ecause transmission rates (which are cost based) represent such a small portion of the total cost of a bundled sale of power . . . we do not believe [allowing a proposed] transmission rate [to go into effect], subject to refund, would permit the utility to exercise market power.").

43. *Wisconsin Elec. Power Co. and Northern States Power Co.*, No. EC95-16-000, 1996 WL 38466, at *7 (Jan. 31, 1996) (to be published at 74 F.E.R.C. ¶ 61,069 (1996)) ("We are concerned about how transmission constraints affect the bounds of the relevant markets within which a wholesale seller's market power will be analyzed").

44. Assessing the impact of transmission constraints on geographic markets can be a complex technical undertaking. Transmission constraints appear and disappear as load and the economics of generation change. Transmission constraints can be thermal or voltage-related. Transmission constraints can even be quasi-contractual, such as "interface limits" between neighboring control areas that do not reflect the greater capability of the regional grid to transfer power.

45. *See infra* Section IV.B.1 (suggesting that the FERC adopt more specific filing requirements).

46. In many instances, however, constraints are regional in nature and thus the data possessed by merging companies may be incomplete.

used in these screening tools should be reproducible and the results verifiable by the participants. The use of public data is important because (i) discovery is not permitted unless a hearing is ordered,[47] and (ii) merging applicants have a limited ability to protect market data they deem confidential.[48]

The FERC's current screening tools generally achieve a fair balance between accurate market measurement and the need for expedition and the use of public data.[49] Perhaps the best example is the FERC's analysis of short-run capacity markets. There are rarely significant disputes regarding the projection of each firm's share of the market, since peak demand and forecasted capacity numbers are reported by each utility to its North American Electric Reliability Council (NERC) region. While interpretation of the data can produce disputes, the collection of it is fairly simple and accurate.

The disputes more commonly center on the appropriateness of using installed capacity shares as a means to evaluate the competitiveness of energy markets. Installed capacity can accurately reflect the competitiveness of energy markets in some cases.[50] However, in other cases, installed capacity shares may be said to understate (or overstate) the merged company's significance in energy markets.[51] In such cases, the FERC can turn to other public information as an additional screening tool. One example is Form 1 data on the annual level of nonfirm energy sales by each firm in the market and for each customer in the market.

There are other ways to modify the FERC's destination market analysis as necessary to account for special circumstances. For example, if a merger occurs in a region with a significant transmission constraint, the geographic market could be modified by reducing the market shares of the sellers located on the constrained side of the interface. As another example, if transmission prices charged in the region are significantly different

47. *Entergy Servs., Inc. and Gulf States Utils. Co.*, 62 F.E.R.C. ¶ 61,073, at 61,369 (1993) (merging applicants are "under no obligation . . . to engage in discovery until the matter [is] set for hearing"). For prudential reasons, however, applicants often accept discovery requests prior to issuance of a hearing order. *See* City of New Orleans v. SEC, 969 F.2d 1163, 1167 (D.C. Cir. 1992) ("[A]n agency's reliance on a report or study without ascertaining the accuracy of the data contained in the study or the methodology used to collect the data 'is arbitrary agency action'.").

48. *See* 18 C.F.R. § 388.112 (1995) (providing rules regarding the submittal of data for which confidential treatment is requested); *Southern Cal. Edison Co. and San Diego Gas and Elec. Co.*, 49 F.E.R.C. ¶ 63,029 (1989) (rejecting request for confidentiality).

49. The FERC calculates each firm's market share in a given destination market using public data on installed capacity and uncommitted capacity. *See Entergy Servs., Inc.*, 58 F.E.R.C. ¶ 61,234, apps. 1-3 (1992) (defining markets and calculating market shares using NERC REPORTS, FERC Form 1s, and ELEC. WORLD, *Directory of Electric Utilities*).

50. *See Kansas City Power & Light Co.*, 67 F.E.R.C. ¶ 61,183, at 61,556 n.11 (1994) ("While installed capacity does not precisely measure the capacity available for nonfirm sales (because native load will never be zero), it does provide an indication of the relative size of the applicant as compared to its competitors.").

51. *See supra* note 32.

than in the ordinary case, the number of "tiers"[52] included in the market could be modified. Each of these modifications could be performed at the screening stage, thereby eliminating the need for further evidentiary proceedings in some cases.

To be sure, however, there will be merger cases that will not pass the applicable market screens and thus will require more detailed scrutiny. In these cases, the FERC will need to consider more carefully the relevant markets and whether they are susceptible to noncompetitive pricing. In some instances, the FERC can do so summarily, without the need for further evidentiary proceedings. Examples include situations where concentration in the market is only slightly above the applicable screening thresholds. Another example is a market where market power is transitory and/or market concentration measurements are misleading.[53]

In other cases, the FERC will find it appropriate to conduct further proceedings (whether a paper hearing or trial-type hearing) on the competitiveness of the relevant markets. In such cases, the FERC will need to give the participants guidance regarding the evidence that should be presented in this more detailed phase of the inquiry. The relevant evidence in this phase will fall into essentially three categories. First, there is evidence relevant to market definition, such as information regarding transmission constraints,[54] transmission prices, and generation price differentials, as appropriate. Second, there is evidence regarding the nature of the market—*i.e.*, even if the market is concentrated, whether it is susceptible to noncompetitive pricing.[55] Third, there is evidence regarding any appropriate remedial conditions, to the extent market power is found to exist.

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52. In FERC parlance, the first "tier" includes those utilities that are directly interconnected with the destination market. The second tier includes those utilities that can access the market by paying one transmission charge (in addition to their own transmission rate).

53. Consider, for example, the short-run capacity market. Market power in this market is short-lived—*i.e.*, it exists only in the period before which new generation can be built. In addition, a firm's possession of a large share of excess capacity may not be a good predictor of its ability to dominate the market. Excess capacity can result from demand forecasting errors, the "lumpiness" of adding new capacity (i.e., increments of new capacity cannot be added to coincide precisely with demand growth) or the loss of load to other suppliers, none of which would necessarily suggest a market-dominating firm. Finally, a firm may have a large share of the capacity market, but supply may exceed demand, thereby causing competitive pricing of capacity.

54. *Wisconsin Elec. Power Co. and Northern States Power Co.*, No. EC95-16-000, 1996 WL 38466 (Jan. 31, 1996) (to be published at 74 F.E.R.C. ¶ 61,069 (1996)) (requesting evidence on the effect of transmission constraints on market definition).

55. For example, in a concentrated Poolco market, would individual firms have an incentive to deviate from coordinated pricing by locking in large volume, long-term energy sales to particular purchasers? *See Merger Guidelines*, *supra* note 14, § 2.12. Do FERC requirements to publish confidential price data actually facilitate coordinated pricing? *See Enron Power Mktg., Inc.*, 66 F.E.R.C. ¶ 61,244 (1994) (regarding requirement to publish confidential price data); *see also Merger Guidelines*, *supra* note 14, § 2.1 (regarding facilitation of coordinated pricing). In addition, the FERC will need to make policy judgments regarding "how much" market power is material under section 203. For example, if a firm could set the price in the wholesale energy market in 500 hours of the year (slightly more than 5% of the hours), would this be a material event necessitating remedial action? Alternatively, if a firm could set the spot price in the wholesale market 30% of the time, but this would affect only 5% of the kilowatt hours generated in those hours (with internal production or long-term energy contracts supplying the balance), would this be a material event?

3. Retail Markets

The foregoing discussion centered on wholesale markets. One issue that has received relatively little attention is whether the Commission, in evaluating a merger's effect on competition, should assess its impact on retail electric markets.

The FERC's current policy is somewhat ambiguous, although it has not been a critical factor in any decision to date. In *Kansas Power & Light Co. and Kansas Gas & Electric*, the Commission stated rather categorically that "[w]e shall not set for hearing issues regarding competition in retail gas and electricity markets because these issues are outside of our jurisdiction."[56] In subsequent cases, however, the Commission has analyzed the effect of mergers on retail competition despite such an apparent lack of jurisdiction to do so.[57]

The issue in future cases will be whether the Commission should (or even has the jurisdiction to) analyze a merger's effect on retail competition. To date, the arguments regarding retail markets have focused on *de minimus* forms of competition, such as customer location competition and fringe area competition.[58] The reason is that, with very few exceptions, direct competition for load at the retail level was not possible. This, of course, is changing and, in the future, direct competition for retail loads may well be the rule, not the exception. The FERC will need to decide whether it will entertain arguments regarding retail issues and, if so, whether the analysis will differ from its analysis of wholesale markets.

III. The Effect on Rates

A mainstay of merger cases at the FERC has been a fairly intensive review of the expected merger-related cost savings and cost increases and any effect thereof on jurisdictional rates. This analysis has not approached the detail of a rate case,[59] but this is not to say that the review has been cursory either.

In the past, the FERC was quite understandably concerned with whether a merger would increase rates to captive requirements custom-

56. 54 F.E.R.C. ¶ 61,077, at 61,254 (1991).

57. *See Entergy Servs., Inc. and Gulf States Utils. Co.*, 62 F.E.R.C. ¶ 61,073, at 61,376 (1993) (considering and rejecting arguments that merger will harm retail competition); *Cincinnati Gas & Elec. Co. and PSI Energy, Inc.*, 64 F.E.R.C. ¶ 61,237, at 62,729 (1993) (considering and rejecting claims that merger would harm retail competition, but noting that "questions relating to competition at the retail level are, as a general matter, more appropriately addressed in state regulatory and judicial proceedings").

58. "Customer location competition" is competition for industrial (or other) load that is considering locating (or expanding) and is willing and able to consider a number of different utility hosts. "Fringe area competition" is competition for customers that are located along a common border between two utilities which both have the right to serve the customer under state law.

59. Merging applicants "need not provide comprehensive cost-of-service data as part of their case-in-chief. Instead, . . . a generalized showing of the types of savings and efficiencies which might be achieved through [a] proposed merger" is all that is required. *Entergy Servs., Inc. and Gulf States Utils. Co.*, 62 F.E.R.C. at 61,372 n.82.

ers.[60] In the future, however, it is unclear whether such an inquiry into cost and rate issues will continue to be meaningful. After passage of the Final Rule in the Commission's Open Access Notice of Proposed Rulemaking (NOPR), all wholesale customers will have the option of purchasing power from a range of suppliers. As a result, there will no longer be captive wholesale customers that can be harmed by a merger in the sense that exists today.[61] If the merged company's prices are noncompetitive, whether because of the merger or otherwise, its customers can and will turn to other suppliers.

As a result, it appears the Commission can discontinue its cost-benefit analysis in merger cases, with perhaps three exceptions. First, over the next few years there will be certain requirements customers whose contracts have not yet expired and thus do not have the ability to shop the market (unless the Commission permits "contract conversion" in the Open Access NOPR[62]). Conceivably, these customers could be harmed by a merger-related rate increase prior to the expiration of their contracts. In most cases, however, merging companies can address this concern by proposing a rate freeze[63] or offering an open season that would let these customers shop for alternative supplies following the merger.[64]

Second, most retail customers do not today have access to alternative power suppliers and thus could be affected by merger-related cost increases. In the ordinary case, the impact of a merger on retail rates will not be an issue at the FERC, given that any affected state commission can address the matter in its review of the merger. In some cases, however, an affected state commission may not have authority to approve a merger and

60. However, the Commission's approach to cost-benefit issues is becoming somewhat confusing. In *Entergy Servs., Inc. and Gulf States Utils. Co.*, the FERC expressed reservations regarding the sustainabilitiy of capacity deferral savings, noting that they "are very sensitive to assumptions made as to the timing of the capacity additions." 62 F.E.R.C. at 61,371. After a hearing on the matter, the FERC found that Entergy had failed to demonstrate *any* such savings. *Entergy Servs. and Gulf States Utils. Co.*, 65 F.E.R.C. ¶ 61,332, at 62,483 (1993). In the Water Power/Sierra Pacific merger, however, the FERC expressed concern that no such savings had been alleged, stating that "combining utilities usually results in significant generation capacity savings by enabling future capital additions to be optimized." *Washington Water Power Co. and Sierra Pac. Power Co.*, 73 F.E.R.C. ¶ 61,218, at 61,595 (1995).

61. There will always be customers whose rates could be affected by a merger. For example, customers that have agreed to purchase energy at the utility's system lambda can be affected by a merger that adds a different resource and load mix. In a competitive environment, it is the customer's choice whether to protect itself against such future contingencies. Negotiating a fixed energy rate, or a rate tied to a published cost index, are two examples of rates that provide protection from changed circumstances.

62. In the NOPR, the Commission requested comment on whether it should permit wholesale customers to terminate their requirements contracts (prior to their natural expiration) and convert to transmission-only service. NOPR, *supra* note 26, at 33,093.

63. *Wisconsin Elec. Power Co. et al.*, 74 F.E.R.C. ¶ 61,069 (1996) (four year rate freeze for wholesale customers eliminates the need for a hearing on cost and rate issues).

64. *See Midwest Power Sys., Inc. and Iowa-Ill. Gas and Elec. Co.*, 71 F.E.R.C. ¶ 61,386 (1995) (open season for wholesale customers if merged company files post-merger rate increase).

may be concerned that the merger will harm its retail ratepayers.[65] In such a case, the FERC will face a sensitive issue of federal-state relations[66] and an interesting issue regarding the appropriate scope of the "public interest" test under section 203.[67]

Third, there may be situations where the applicants themselves argue that any negative competitive impacts of the merger are more than offset by the efficiencies produced by the merger. The Merger Guidelines provide that "[s]ome mergers that the Agency otherwise might challenge may be reasonably necessary to achieve significant net efficiencies."[68] If the Commission adopts the same approach, merging applicants may choose themselves to support their merger with projected efficiencies, thereby placing the level of such savings and whether they could be achieved without the merger in issue.[69]

IV. Procedural Reforms

A. *Defects in the Current System*

Utility merger cases at the FERC suffer from many of the same procedural defects as afflict other administrative proceedings.[70] The purpose here is to identify the shortcomings that are fairly unique to merger cases or at least that are of magnified significance in merger cases. A short list is provided below.

First, unlike electric rate cases, the Commission's regulations provide little guidance as to the kind of information that should be submitted with a merger application on the key issues, such as the effect on competition.[71] As a result, merger applicants are free to fashion their testimony in any way they like and intervenors are free to criticize it as "deficient," with

65. This situation arose in both the Cincinnati Gas & Electric/PSI Energy and Entergy Services/ Gulf States Utilities merger cases, where certain state commissions alleged that they would not have authority to approve the merger and that the FERC should therefore undertake an inquiry into the costs and benefits of the merger.

66. Moot, *supra* note 4, at 15-16 (arguing that, absent exceptional circumstances, the FERC should not consider retail rate issues).

67. Other than rates for interstate retail wheeling, the FERC has no jurisdiction over retail rate matters. The general rule is that only those matters relevant to the FERC's mandate under the FPA will be considered in a given proceeding. This means, for example, that the FERC will not hold hearings on discriminatory employment practices, NAACP v. FPC, 425 U.S. 662 (1976), or on pole attachment disputes with telecommunications firms. *Washington Water Power Co. and Sierra Pac. Power Co.*, 73 F.E.R.C. ¶ 61,218 (1996).

68. *Merger Guidelines*, *supra* note 14, § 4. "Cognizable efficiencies include, but are not limited to, achieving economies of scale, better integration of production facilities, plant specification, lower transportation costs, and similar efficiencies relating to specific manufacturing, servicing, or distribution operations of the merging firms." *Merger Guidelines*, *supra* note 14, § 4.

69. The Guidelines provide that the DOJ/FTC "will reject claims of efficiencies if equivalent or comparable savings can reasonably be achieved by the parties through other means." *Merger Guidelines*, *supra* note 14, § 4.

70. In Docket No. RM96-6-000, *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act* (Jan. 31, 1996), the Commission has requested comment on whether there are procedural reforms that could expedite the merger review process.

71. *See* 18 C.F.R. § 33 (1995).

neither side having a firm understanding of whether the applicants have submitted the type of information the Commission deems relevant and appropriate.

Second, at the initial phase of a merger case (before the Commission issues a hearing order or approves the merger summarily), there is a seemingly endless exchange of "answers to protests" and "answers to answers" and "replies to responses" that often fail to provide any new information or argument that would be of value to the Commission. If this process were simply annoying, but nothing more, it would not deserve mention here. But it is more than annoying. The exchange of pleadings ordinarily carries on for several *months*, thereby bogging the Commission Staff down with so much material that it becomes difficult even to issue a hearing order on a timely basis.[72]

Third, between the time an application is filed and the time the Commission acts on it, there is ordinarily no communication with the Commission's advisory staff. Unlike electric rate cases, where the Staff in complex cases routinely issues "deficiency" letters requesting additional information, the Staff handling electric merger cases ordinarily is silent as to any misgivings it may have, or additional information it needs, regarding a merger application until the time a hearing order issues.[73]

Fourth, the process is undisciplined in that intervenors often raise issues that have no bearing on their own interests. This occurs most frequently where there is a rival bidder for the utility being acquired. Since the FERC's rules do not explicitly preclude these tactics, a rival bidder has every incentive to delay the process with as many arguments as can be constructed.

Fifth, the hearings, when they are conducted, often take too long. From the date a hearing order issues to the date an initial decision issues may range from six months to an unlimited period.[74] It is proposed here that the *maximum* period be six months.

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72. As an example, in the Entergy Services/Gulf States Utilities merger, pleadings were filed by the parties virtually every week during a five-month period from September 1992, when the application was noticed, to January 1993, when the Commission set the matter for hearing. *See Entergy Servs., Inc. and Gulf States Utils. Co.*, 62 F.E.R.C. ¶ 61,073 (1993), *reh'g denied*, 64 F.E.R.C. ¶ 61,001 (1993). This deluge of pleadings, along with the time it takes to sort out issues which require a hearing and issues that can be decided summarily, has contributed to substantial delays in several cases. In *Wisconsin Elec. Power Co. and Northern States Power*, 74 F.E.R.C. ¶ 61,069 (1996), more than six months elapsed before the case was set for hearing. In *El Paso Elec. Co. and Central & S.W. Servs., Inc.*, 68 F.E.R.C. ¶ 61,181 (1994), it took seven months to set the matter for hearing.

73. The exceptions have been the PSI Energy/CG&E merger case, *see Cincinnati Gas & Elec. Co. and PSI Energy, Inc.*, 64 F.E.R.C. ¶ 61,237 (1993); Letter from Director, Div. of Opinions and Systems Analysis, OEPR, to C.M. Naeve (July 23, 1993) (on file with author); and the Cleveland Electric/Toledo Edison merger case, where a deficiency letter also was issued.

74. The most expedited was *Utah Power & Light Co. and Pacific Power & Light Co.*, where the presiding judge was given six months to issue an initial decision, even though the company had not yet filed its case-in-chief. 41 F.E.R.C. ¶ 61,283, at 61,755 (1987). The slowest likely will be *Washington Water and Power and Sierra Pacific Power Co.*, where the Commission did not provide a deadline for issuing an initial decision, 73 F.E.R.C. ¶ 61,218 (1995). In *Northeast Utils. Serv. Co.*, the presiding judge was given ten months to issue an initial decision, 50 F.E.R.C. ¶ 61,266, at 61,840-41 (1990). In *Entergy*

B. *Proposed Reforms*

1. Filing Requirements

An ounce of prevention is worth a pound of cure. With this in mind, the first place to start in reforming the procedural process of FERC merger cases is to provide more detailed filing requirements for merger applicants. As indicated above, the current filing requirements for section 203 applications are lengthy, but they specify information that is rarely of any value in deciding the key issues in the case. Rather, the required information consists largely of descriptions of physical facilities and the submission of merger-related documents. But as to the key issues in the case—*e.g.*, the effect of the merger on competition—there is no guidance. The Commission's regulations simply instruct merging applicants to describe "[t]he facts relied upon . . . to show that the proposed . . . merger . . . will be consistent with the public interest."[75]

Given the complexity of merger cases, this is not good enough. The FERC should provide detailed filing requirements on each issue it deems important.

2. Reducing the Time Period for Processing a Merger Application

The current process for evaluating merger applications is inefficient. The defects in the process were perhaps most visible in the *Washington Water Power Co. and Sierra Pacific Power Co.* case, where the Commission, sixteen months after the application was filed, set the case for a non-expedited hearing. There are other examples as well. In cases involving the resolution of a utility bankruptcy, the Commission in *Northeastern Utilites Service Co.* took seventeen months to decide the case and in *El Paso Electric Co. and Central & South West Services, Inc.* it took fifteen months just to get an ALJ decision.[76]

These delays have real costs. The costs include lost savings to ratepayers where the achievement of merger synergies is delayed. They include the psychological strain on employees whose futures are "up in the air" for as long as two years. They include the litigation costs of both the applicants and the intervenors. The cost of litigating a lengthy merger case is immense, with some of the efforts, I would suggest, being unproductive or overdone on both sides of the case.

The existing merger review process, it is submitted, can be streamlined without sacrificing any party's procedural rights or the Commission's ability to gather evidence relevant to its "public interest" mandate under section 203. While there are a range of potential solutions, the following proposal offers a "two track" process that allows merging applicants to

Servs., Inc. and Gulf States Util. Co., the presiding judge was given seven months to issue an initial decision. 62 F.E.R.C. ¶ 61,073, at 61,378 (1993). In *El Paso Elec. Co. and Central & S.W. Serv., Inc.*, the presiding judge was given seven months to issue an initial decision, 68 F.E.R.C. ¶ 61,181, at 61,920 (1994).

75. 18 C.F.R. § 33.2(j) (1995).

76. The merger later collapsed and the application was withdrawn before final Commission action.

choose the track best suited to expediting their transaction. Both tracks are described below.

a. Track 1: An Expedited Hearing

The "Track 1" procedure is as follows. The utility files its case-in-chief and the case is immediately set for an expedited evidentiary hearing. The evidentiary hearing encompasses all relevant issues.[77] As a result, the hearing order is largely a ministerial act that can be issued within thirty days of the date the application is filed. An expedited hearing then ensues, with the Commission issuing a final order on the application within ten months of the date it was filed.

An example of the procedural dates necessary to achieve such expedition is provided below:

Date	Procedural Step
Day 1	Merger application filed
Day 7	Notice of filing issues
Day 21	Motions to intervene due[78]
Day 30	Order setting merger for hearing
Days 30-75	Rolling discovery period
Day 75	Intervenor/Staff testimony due
Day 95	Applicants' rebuttal testimony[79]
Day 105	Hearing commences
Days 120-150	Post-hearing briefing period
Day 195	Initial decision issues
Day 215	Briefs on exceptions
Day 230	Briefs opposing exceptions
Day 290	Commission opinion

This process would be particularly beneficial for controversial mergers that would be set for hearing in any event. The Track 1 process also would be beneficial to any other applicant that desired to have its merger reviewed within a time certain.

b. Track 2: Approval Without a Hearing if no Material Factual Disputes Exist

"Track 2" is similar to the process that exists today, although it is a bit more structured. The applicants file their case-in-chief and request approval without a hearing on any issue. The application is noticed and intervenors have the opportunity to protest it, including submitting evidence demonstrating that there are material factual disputes requiring a

77. The process of entrusting an administrative law judge to decide all relevant issues is the standard practice in electric rate cases. *See Cincinnati Gas & Elec. Co.*, 59 F.E.R.C. ¶ 61,072, at 61,291 (1992).

78. The ALJ would have the authority to rule on any objections to motions to intervene.

79. If deemed necessary, intervenor and staff "cross-rebuttal" could be submitted on this date as well.

hearing. The applicants then are permitted a reply. The Commission's advisory staff, if appropriate, requests additional information through a "deficiency letter," just as it does in electric rate cases. After any such information is submitted, the Commission considers whether the application can be approved without a hearing. If this is possible, the Commission does so within six months from the date the application was filed. If not, the Commission sets any material issues of fact for an expedited hearing following procedures similar to those outlined above for Track 1 hearings.

An example of the Track 2 procedure is provided below:

Date	Procedural Step
Day 1	Merger application filed
Day 7	Notice of filing issues
Day 28	Motions to intervene/protests
Day 42	Applicants' reply brief[80]
Days 56	Intervenor surreply[81]
Day 70	FERC deficiency letter (if any)
Day 90	Response to deficiency letter
Day 110	Intervenor answer to Applicant's response
Days 110-180	Commission order on merger

Track 2 would be best suited for noncontroversial cases or aggressive applicants that believed they could address all the significant intervenor and FERC concerns without a hearing.

The benefits of the foregoing two-track proposal lie primarily in its use of procedures that are familiar to the FERC and its practitioners, and the protection afforded to the procedural rights of all parties. While this proposal is not the only way in which the process could be improved, it is nevertheless a modest step in the right direction.

3. Stalking Horses

For the most part, the opposing parties in merger cases possess genuinely held differences of opinion regarding issues of substantial economic significance to them. There are exceptions, however. The most notable exception is the intervenor that has an interest in stopping a merger and attempts to do so by raising every colorable issue, regardless of whether the issue affects *its* interests. This most often occurs with frustrated suitors—*i.e.*, utilities that have been unsuccessful in acquiring one of the merging applicants. It also can occur with smaller rivals that fear the creation of a

80. The Commission's procedural rules would be amended to provide merging applicants the opportunity to submit a reply brief, even if the comments on the application were styled as "protests." *See* 18 C.F.R. § 385.213 (1995) (answers to protests not permitted). In virtually every phase of civil procedure, the "plaintiff" or "petitioner" (i.e., the person requesting relief from the court) is permitted to rebut the arguments of the defendant/respondent, either with rebuttal testimony or with a reply brief. The FERC should adopt this model for its merger proceedings (if not all its cases).

81. A surreply would be permitted as necessary to respond to new commitments offered by the applicants or new evidence submitted by the applicants in their reply.

formidable competitor. In either instance, the incentive, if unrestrained by Commission procedural rules, is to raise every possible issue and delay consideration of the proposed merger.

Unfortunately, the Commission's procedural rules do little to discourage such conduct (although, to be sure, they do not condone it). Traditionally, the only means of limiting such parties is to oppose their motion to intervene, but this is usually a futile act. One option would be to adopt an "aggrievement" test similar to that provided in Federal Power Act (FPA) section 313(a), which permits a person to seek rehearing of a Commission order only if it is "aggrieved" thereby.[82]

A good illustration of the "aggrievement" test is found in *Utility Users League v. FPC*,[83] a merger case. There, customers of Commonwealth Edison Company (Edison) petitioned for review of a Commission order approving a merger of Central Illinois Electric & Gas Company (Central) with and into Edison. The Edison customers alleged, *inter alia*, that "Edison's ownership of both Central's electric properties and its gas properties may be injurious to energy consumers . . . served *by Central*."[84] The Court denied the petitions for review, holding in part that Edison customers were not "aggrieved by higher rates for former Central customers."[85] More generally, the Court held that "injury to the consumer cannot be inferred from a merger, but must be demonstrated"[86] and, further, that to be "aggrieved," a party must show that a merger "has a significant detrimental effect on [it], either actually or potentially."[87]

There is no reason why the FERC could not apply these principles to the pre-decision stages of a merger case. Arguably, a party that is not aggrieved by a particular aspect of a merger (such as its effect on rates) should not be permitted to contest that aspect of the merger.[88]

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82. 16 U.S.C. § 825l(a) (1994). "Aggrievement" is "determine[d] . . . on the basis of the specific facts in each case." Florida Power & Light Co. v. FERC, 617 F.2d 809, 814 (D.C. Cir. 1980) (citing *Northeastern Pub. Serv. Co. v. FPC*, 520 F.2d 454 (D.C. Cir. 1975)). A party must demonstrate that it has sustained an "injury in fact" as a result of a Commission order. *See* Chenehuevi Tribe of Indians v. FPC, 489 F.2d 1207, 1212 n.12 (D.C. Cir. 1973). "[T]he 'injury in fact' test requires more than an injury to a cognizable interest. It requires that the party seeking review be himself among the injured." Sierra Club v. Morton, 405 U.S. 727, 734-35 (1971); *see Arizona Pub. Serv. Co.*, 26 F.E.R.C. ¶ 61,357, at 61,792 (1984) (party must be "prejudiced" by a Commission order). Furthermore, "a petitioner's aggrievement must be present and immediate, or at least must be demonstrably a looming unavoidable threat." Cincinnati Gas & Elec. Co. v. FPC, 246 F.2d 688, 694 (D.C. Cir. 1957). A "remote possibility" of injury is insufficient. *Id.*

83. 394 F.2d 16 (7th Cir. 1968).

84. *Id.* at 20 (emphasis added).

85. *Id.*

86. *Id.*

87. *Id.* at 19.

88. In section 211 cases, the FERC precludes intervenors that are non-parties to the transaction from filing briefs prior to the final order in the case. They are limited to filing rehearing petitions *if* the final order aggrieves them. *See, e.g., Duquesne Light Co.*, 71 F.E.R.C. ¶ 61,155 (1995).

V. IMPLEMENTING POLICY REFORM

If reform of the Commission's merger policy is desirable, the Commission must choose whether to pursue it through a generic proceeding, such as a rulemaking or policy statement, or through adjudicating individual cases. The Commission has considerable latitude in making this choice:

> The function of filling in the interstices of the Act should be performed, as much as possible, through . . . quasi-legislative promulgation of rules to be applied in the future. But any rigid requirement to that effect would make the administrative process inflexible and incapable of dealing with many of the specialized problems which arise. Not every principle essential to the effective administration of a statute can or should be cast immediately into the mold of a general rule. Some principles must await their own development, while others must be adjusted to meet particular, unforeseeable situations. In performing its important functions in these respects, therefore, an administrative agency must be equipped to act either by general rule or by individual order. To insist upon one form of action to the exclusion of the other is to exalt form over necessity.[89]

The Commission's notice of inquiry on merger policy does not suggest whether the Commission intends to implement policy reform (if any) on a generic or case-by-case basis. The notice of inquiry could result in the promulgation of a rule (or policy statement) or it could simply serve as a vehicle for gathering information and opinions from all industry segments, with any policy reform thereafter being implemented in the context of deciding individual cases.

Both vehicles of policy change, the issuance of generic rules and the use of case-by-case adjudication, have benefits and costs.[90] The choice for the FERC, as to its merger policy, should be influenced by the nature of the policy reform envisioned. Many of the reforms proposed in this article could be implemented in individual cases, or a single case. In this category are: (i) adopting the Merger Guidelines, and (ii) eliminating, or limiting, the circumstances under which transmission would be deemed a relevant product market. By contrast, other proposals, such as reforming the procedural process, might be better accomplished through a rulemaking proceeding.

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89. SEC v. Chenery Corp. (*Chenery II*), 332 U.S. 194, 202 (1947). This general rule was complicated by the decision of a divided court in *NLRB v. Wyman-Gordon Co.*, 394 U.S. 759 (1969), where in plurality and dissenting opinions, six of the nine justices indicated that prospective rules should be promulgated through rulemaking rather than adjudicatory procedures. Only three justices, who voted with the plurality in upholding the rule, separately argued that the choice between rulemaking and adjudication was within the discretion of the agency. *See* Mark H. Grunewald, *The NLRB's First Rulemaking: An Exercise in Pragmatism*, 41 DUKE L.J. 274, 279 (1991). Five years later, however, the Court in *NLRB v. Bell Aerospace Co.*, 416 U.S. 267 (1974), reaffirmed *Chenery II*. *See generally* Richard K. Berg, *Re-examining Policy Procedures: The Choice Between Rulemaking and Adjudication*, 38 ADMIN. L. REV. 149 (1986).

90. *See generally* Arthur E. Bonfield, *State Administrative Policy Formulation and the Choice of Lawmaking Methodology*, 42 ADMIN. L. REV. 121, 127 (1990); Morton C. Bernstein, *The NLRB's Adjudication-Rule Making Dilemma Under the Administrative Procedure Act*, 79 YALE L.J. 571 (1970); Richard J. Pierce, Jr., *The Unintended Effects of Judicial Review of Agency Rules: How Federal Courts Have Contributed to the Electricity Crisis of the 1990s*, 43 ADMIN. L. REV. 7, 12 (1991).

VI. Conclusion

Section 203 of the FPA provides the FERC with significant authority to shape the future structure of the electric utility industry. The FERC should exercise this authority prudently, with due regard to the reality that competition works better than regulation. For the FERC, this means carefully selecting the type of regulation it pursues. Second guessing whether a particular merger makes good business sense or will create a more efficient firm are matters particularly ill-suited to the regulatory process. These decisions can generally be left to utility executives and shareholders. Competition will be more than adequate to discipline any mergers that do not live up to expectations.

The goal should be to ensure that competition will remain a disciplining force following a merger. This means carefully considering the potential competitive impacts of a merger. In doing so, however, the FERC must remain cognizant of the interplay between its merger review standards and its other policies. FERC decisions regarding transmission pricing and future market institutions (such as Poolcos) will have a significant impact on the size and nature of markets. This, in turn, will affect the degree to which particular mergers may, or may not, harm competition. The FERC's merger policies must not only be rational and clearly articulated, but coordinated with its other policies to achieve the common goal of more efficient bulk power markets.