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INDEPENDENT TRANSMISSION COMPANIES: THE FOR-PROFIT ALTERNATIVE IN COMPETITIVE ELECTRIC MARKETS

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I. INTRODUCTION

The Federal Energy Regulatory Commission (FERC or Commission) over the last fifteen years has encouraged the transition of the bulk power market from traditional cost-based regulation to competition in the wholesale sales of vertically-integrated utilities. As part of its strategy, the Commission has progressively required transmission owners to: (1) provide transmission access to third parties so competing buyers and sellers of power are able to reach one another; (2) provide transmission service comparable to what the transmission provider has on its own system; and (3) provide transmission service under standard terms, conditions, and basic rates. This last step produced Order No. 888 and its progeny,¹ the Commission's largest single restructuring effort in the

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1. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, F.E.R.C. STATS. & REGS., Regs. Preambles ¶ 31,036, 61 Fed. Reg. 21,540 (1996) (codified at 18 C.F.R. pts. 35, 385) [hereinafter Order No. 888], *order on reh'g*; Order No. 888-A, III F.E.R.C. STATS. & REGS., Regs. Preambles ¶ 31,048 (1996), 62 Fed. Reg. 12,274 (1997) (codified

electric utility industry to date. In Order No. 888, the Commission required utilities to "functionally unbundle" their wholesale generation and transmission services.²

In Order No. 888, the Commission also encouraged, but did not require, several forms of corporate restructuring, including the formation of Independent System Operators (ISOs), as a means of furthering the transition to a competitive bulk power market.³ To date, three Commission-approved ISOs (California, ISO New England, and PJM) are in operation. In addition, the Commission has conditionally authorized the establishment of the New York ISO and the Midwest ISO. An ISO is also currently operating in the Electric Reliability Council of Texas (ERCOT), which is subject primarily to the jurisdiction of the Public Utility Commission of Texas.

In the absence of evidence that functional unbundling is insufficient to achieve a workably competitive market, the Commission stated in Order No. 888 it would not be prepared to require public utilities to participate in ISOs.⁴ However, through Docket No. PL98-5-000 and the regional ISO conferences, the Commission has now begun to consider whether functional unbundling will be sufficient to complete the transition to a competitive bulk power market or whether it should take further steps to encourage corporate restructuring. In addition, individual Commissioners have raised the issue of whether ISOs are the only corporate restructuring model capable of ensuring transmission facilities are managed and operated in a manner that best facilitates the development of competitive bulk power markets.⁵

at 18 C.F.R. pt. 35), [hereinafter Order No. 888-A], *order on reh'g*; Order No. 888-B, 81 F.E.R.C. ¶ 61,248 (1997) [hereinafter Order No. 888-B], *order on reh'g*; Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998).

2. Functional unbundling requires that a transmission provider (1) take transmission service (including ancillary services) for all its wholesale sales and purchases under the same tariff of general applicability as all of its transmission customers; (2) state separate rates for wholesale generation, transmission and ancillary services; and (3) rely on the same electronic information network that its customers rely on for obtaining transmission service. Order No. 888, *supra* note 1, at 31,654.

3. The Commission stated it would "accommodate other mechanisms that public utilities may submit, including voluntary corporate restructurings (e.g., ISOs, separate corporate divisions, divestiture, poolcos), to ensure that open-access transmission occurs on a non-discriminatory basis." Order No. 888, *supra* note 1, at 31,656. The Commission therefore considers both the ISO and corporate divestiture models as "corporate restructurings." Strictly speaking, however, in the ISO model, the transmission assets remain within the utility's corporate structure and the generation and transmission functions are only operationally unbundled. Nevertheless, this article will follow the Commission's approach and will refer to both ISO and ITC formations as corporate restructuring models.

4. Order No. 888, *supra* note 1, at 31,655, 31,730. *See also* Order No. 888-A at 30,186 ("We see no need to adopt a more intrusive and potentially more costly approach at this time based on speculative allegations that functional unbundling may not work and that more severe measures may be needed.").

5. *See, e.g.*, Hon. Curt L. Hebert, Jr., *The Quest For An Inventive Regulatory Agenda*, 19 ENERGY L.J. 1,9 (1998), in which Commissioner Hebert criticized the "cumbersome structures" of ISOs. Commissioner Hebert suggested that "thorny problems" associated with ISOs cannot be resolved with Commission involvement, and concluded that a for-profit transmission company may

Regardless of whether the Commission concludes the functional unbundling requirement is sufficient to achieve competition, the Commission should continue to encourage corporate restructuring as a means to achieve greater competition in the bulk power markets. Indeed, the benefits of corporate restructuring are far more tangible and more likely to succeed in the long-term. The Commission should not limit its consideration of corporate restructuring models only to ISO formation, but should also be open to the viability of other restructuring models. The most promising ISO alternative encourages voluntary corporate restructuring by authorizing incentive-based rates for utilities, which establish for-profit independent transmission companies (ITCs).⁶

Economics and experience suggest that the desegregation of the electric utility industry into sectors organized along the lines of competitive markets, including a segregated transmission function, can proceed more quickly with proper market incentives. Both ITCs and ISOs can facilitate the Commission's goal for a competitive electric market. Just as the Commission has encouraged the formation of ISOs, it can use incentive-based rates to encourage the development of ITCs. While the Commission has never considered incentive-based rates for a transmission-only utility, they are critical to encouraging the formation of for-profit transmission providers. We therefore suggest that the Commission spell out a program for incentive-based rates to facilitate the various corporate restructuring proposals put forth by the industry. Since both ISOs and ITCs have benefits under different circumstances, we believe the Commission should encourage both models. This article will concentrate on the formation and incentives of ITCs.

prove to be a more appropriate alternative for achieving competition in the electric industry. *Id.* at 10. In addition, at the ISO conference in Washington, D.C., Commissioner Bailey, although not directly attacking the merits of ISOs, stated that she "would not want initiatives in favor of ISOs to stifle other innovations, becoming too static to the disfavor of all other alternatives." Hon. Vicky A. Bailey, Comments Before the Washington, D.C. ISO Conf. (Apr. 15, 1998), in F.E.R.C. Docket No. PL98-5-000, at 3. She further observed that "[p]erhaps independent operation of the grid independent of ownership may not necessarily be a good thing. The combination . . . of operational control and ownership . . . has its advantages in some areas and in some locales." *Id.* Commissioner Bailey's comments may reflect a concern that ISOs may not be the appropriate regional transmission provider for ensuring competition in the bulk power market in all instances.

6. The terminology surrounding independent transmission companies has been confusing at best, with such entities at times being referred to as Transcos or Gridcos. Hon. Curtis L. Hebert, Comments Before the New Orleans, L.A. ISO Conf. (June 1, 1998), in F.E.R.C. Docket No. PL98-5-000, at 11. The differences in terminology reflect a substantive distinction as to what these entities are intended to accomplish, and how they should be structured and operated. In order to avoid any pre-existing notions that the reader might have regarding these terms, the authors have chosen to refer to these entities as independent transmission companies, or ITCs. By ITCs, the authors are referring to companies that are investor-owned and operated as for-profit entities, that do not own any interest in distribution or generation facilities, that only have transmission assets transferred from a vertically-integrated utility or utilities, that are unaffiliated with any other market participant, and that operate the control area.

II. THE FACTORS DRIVING THE RESTRUCTURING OF THE ELECTRIC INDUSTRY

A. Historical Background

The current drive for independent transmission providers, including both ISOs and ITCs, started with the emergence of competition in the electric generation market. Since the early part of this century, electric utilities have been organized into single corporate entities that own and operate generation, transmission, and distribution facilities.⁷ Initially, these vertically-integrated utilities served limited areas and were "predicated on the concept that a central source of power supplied by efficient, low-cost utility generation, transmission, and distribution was a natural monopoly."⁸ Generally, these utilities built generating facilities in the proximity of their customers, and transmission was treated essentially "as an incidental service."⁹ For much of this century, the electric industry was able to meet the increasing demand of the consumers at decreasing prices as they capitalized on the economies of scale of their large, integrated systems and on technological advancements in the generation and transmission of power.¹⁰

Beginning in the mid-1960s, however, a number of events in the energy industry began to provide the initial impetus towards competition in the generation market.¹¹ The costs of nuclear facilities and other baseload generating facilities skyrocketed while the expected increases in demand that had earlier appeared to justify the construction of such capital-intensive facilities did not materialize.¹² Electric utilities found they had excess capacity while their unit costs were escalating. Advancements, such as combined cycle generating technology, resulted in the increased efficiency of smaller generating plants, thereby diminishing the traditional benefits of the scale economies offered by the vertically-integrated utilities.¹³

In an effort to promote energy conservation and efficiency, Congress passed the Public Utility Regulatory Policies Act (PURPA) in 1978, which allowed certain non-utility generators to participate in the wholesale

7. ENERGY INFORMATION ADMINISTRATION, THE CHANGING STRUCTURE OF THE ELECTRIC POWER INDUSTRY: AN UPDATE 5 (1996) [hereinafter EIA Dec. 1996 Report].

8. *Id.* at 5.

9. Hebert, *supra* note 5, at 2.

10. EIA Dec. 1996 Report, *supra* note 7, at 7.

11. For a description of the changes in the electric utility industry in the 1960s and 1970s, see CHARLES F. PHILLIPS, JR., THE REGULATION OF PUBLIC UTILITIES: THEORY AND PRACTICE (2nd ed. 1988). See also EIA Dec. 1996 Report, *supra* note 7.

12. EIA Dec. 1996 Report, *supra* note 7, at 109-10.

13. Order No. 888, *supra* note 1, at 31,641.

power market.¹⁴ PURPA created a viable market for power produced by certain independent generators by requiring public utilities to purchase power from any facility meeting the criteria of a Qualifying Facility (QF).¹⁵ Unlike the traditional cost-based determination of purchased power costs, PURPA required utilities to purchase QF-produced power at the utility's "incremental cost of alternative electric energy."¹⁶ The proliferation of QFs in the wake of the enactment of PURPA demonstrated the entrepreneurial interest in providing alternative sources of reliable power. When presented with the opportunity, nontraditional suppliers indicated a willingness to make sufficient investments to enlarge the nation's generating capacity. While many observers contend this increase in capacity was induced by state-mandated prices, which were in excess of the utility's legitimate incremental cost,¹⁷ many public utilities nonetheless found economic efficiencies could be realized by purchasing power from alternative sources, rather than in constructing new facilities.¹⁸

Meanwhile, other non-utility generators found sufficient incentives to develop alternative sources of supply, even without the benefit of QF status.¹⁹ With traditional utilities wary of investing in new generation under the existing cost-of-service ratemaking regulation, these non-utility generators were eager to take advantage of the opportunity to earn market-based rates.²⁰ However, the development of these market participants was inhibited by their lack of access to essential transmission facilities to reach their customers. Recognizing this obstacle, Congress passed the Energy Policy Act (EPACT) in 1992.²¹ EPACT amended the

14. Public Utilities Regulatory Policies Act, § 210, 16 U.S.C. § 824a-3 (1998) [hereinafter PURPA].

15. "Qualifying facilities" include (i) small power production facilities (generally of 80 MW or less) that use solar, wind, and various renewable resources, and (ii) cogeneration facilities, which combine electric generation with the production of steam for industrial or heating purposes. 16 U.S.C. §§ 796(17), (18) (1994); Conservation of Power and Water Resources, 18 C.F.R. §§ 292.202 -.205 (1998).

16. PURPA defines "incremental cost of alternative electric energy" as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." 16 U.S.C. § 824a-3(d) (1994).

17. EIA Dec. 1996 Report, *supra* note 7, at 41.

18. Order No. 888, *supra* note 1, at 31,644.

19. These nontraditional power producers, known as Independent Power Producers (IPPs), were generally single asset generation companies that were unaffiliated with any utility and that were not involved in transmission or distribution functions. Such entities were not constrained by PURPA's operational, size, and technological criteria. To capitalize on the potential greater earnings possible with independent, non-rate based generation, public utilities began to establish similar entities called Affiliated Power Producers (APPs) in order to sell power in both their own service territory as well as in the service territory of other utilities. *Id.* at 31,642. At the same time that IPPs and APPs emerged as market participants, power marketers came into existence as entities that buy and sell power, but own no generation or transmission. *Id.* at 31,643. The business of power marketers is predicated on the ability to arbitrage between regions of excess supply and regions of inadequate supply, and therefore, marketers are especially reliant on access to transmission in order to move energy.

20. See, e.g., *Commonwealth Atl. Ltd. Partnership*, 51 F.E.R.C. ¶ 61,368 (1990).

21. Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992) (codified at 42 U.S.C. § 13201).

Federal Power Act (FPA) to provide that any entity selling power at wholesale could request that the Commission order a transmission-owning utility to provide transmission service under sections 211 and 212 of the FPA.²²

The Commission quickly took advantage of its new authority to order transmission service (also known as "wheeling"), even going so far as requiring that a transmission owner provide its competitors with network service across its system.²³ However, given the time and resources involved in obtaining a wheeling order, sections 211 and 212 did not entirely resolve the problem of transmission access for third parties.²⁴ Despite the Commission's authority to order transmission access to a utility's grid, "in many instances transmission customers did not receive the flexibility of service that transmission owners retained for themselves."²⁵ Moreover, even though many utilities had filed an open-access tariff in order to obtain approval for a merger²⁶ or to obtain blanket authorization to charge market-based rates,²⁷ most transmission owners did not apply for a merger or market-based rates, and therefore, did not have an open-access tariff on file.

In 1993, the Commission announced that it would apply a new standard to be used in determining whether a utility was providing nondiscriminatory open-access to a third party. In *American Electric Power Service Corporation (AEP)*, the Commission held that a public utility's voluntarily filed open-access tariff must offer transmission services to third parties *comparable* to the services used by the utility itself.²⁸ The

22. PURPA also included a provision that allowed the Commission to order wheeling for power generated by a third party under certain narrowly-defined circumstances. However, the Commission quickly interpreted this already limited authority very conservatively. *Southeastern Power Admin. v. Kentucky Utils. Co.*, 25 F.E.R.C. ¶ 61,204 (1983) (holding that the Commission could not order wheeling if the wheeling order would result in a disturbance of existing market patterns, and holding that section 211 of the FPA, as added by PURPA, was not designed to remedy a utility's anticompetitive conduct). EPACT amended sections 211 and 212 of the FPA to expand the Commission's authority to order wheeling upon application. 16 U.S.C. §§ 824j, 824k (1994).

23. *Florida Mun. Power Agency v. Florida Power & Light Co.*, 67 F.E.R.C. ¶ 61,167 (1994), *reh'g denied*, 74 F.E.R.C. ¶ 61,006 (1996). The advantage of network service is that it allows a customer to serve its native load from multiple resources much like the transmitting utility's own use of the system, in contrast to more limited point-to-point transmission service to which most transmission service had historically been limited.

24. Order No. 888, *supra* note 1, at 31,673.

25. ENERGY INFORMATION ADMINISTRATION, THE CHANGING STRUCTURE OF THE ELECTRIC INDUSTRY: SELECTED ISSUES 31 (1998) [hereinafter EIA July 1998 Report].

26. See, e.g., *Utah Power & Light Co.*, 45 F.E.R.C. ¶ 61,095 (1988), *order on reh'g*, 47 F.E.R.C. ¶ 61,209 (1989), *order on reh'g*, 48 F.E.R.C. ¶ 61,035 (1989), *aff'd sub nom*, *Environmental Action Inc. v. FERC*, 939 F.2d 1057 (D.C. Cir. 1991).

27. See, e.g., *Public Serv. Co. of Ind.*, 51 F.E.R.C. ¶ 61,367 (1990), *reh'g denied*, 52 F.E.R.C. ¶ 61,313 (1990), *appeal dismissed sub nom*, *Northern Indiana Public Service Co. v. FERC*, 954 F.2d 736 (D.C. Cir. 1992).

28. *American Elec. Power Serv. Corp.*, 64 F.E.R.C. ¶ 61,279 (1993), *order on reh'g and clarification*, 67 F.E.R.C. ¶ 61,168, *clarified*, 67 F.E.R.C. ¶ 61,317 (1994). The Commission stated that "traditionally the focus of our undue discrimination analysis has been whether factual differences justify different rates, terms and conditions for similarly situated customers However, due to

Commission held that otherwise, the utility's open-access tariff would be unduly discriminatory and anticompetitive under the FPA.²⁹

B. Order No. 888 and the Functional Unbundling Requirement

Despite the Commission's vigorous application of the comparability standard in a number of contexts,³⁰ barriers to transmission access persisted. Many vertically-integrated utilities still did not provide open-access to third parties. In addition, when utilities did provide open-access service, they typically favored their own generation.³¹ To address the continuing problem of transmission access, on April 24, 1996, the Commission issued its Final Rule, Order No. 888. This Order promoted wholesale competition through nondiscriminatory transmission access. The Commission noted the "legal and policy cornerstone of [Order No. 888] is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce."³² Order No. 888 required all transmission owners to: (1) offer comparable open-access transmission service for wholesale transactions under a tariff of general applicability on

changing conditions in the electric utility industry, e.g., the emergence of non-traditional suppliers and greater competition in bulk power markets, the focal point of claims of undue discrimination has changed from discrimination in the treatment of different customers to discrimination in the rates and services the utility offers third parties when compared to its own use of the transmission system." 67 F.E.R.C. at 61,490 (footnote omitted).

29. While the Commission's newly announced comparability standard imposed additional burdens on the transmission owner who sought to file an open-access tariff, compliance with that standard offered certain benefits as well. In *Kansas City Power & Light Company*, the utility requested blanket authority to sell generation from new capacity at market-based rates. 67 F.E.R.C. ¶ 61,183 (1994) [hereinafter *KCPL*]. The Commission authorized the sale, contingent on the filing of a comparable open-access tariff, and announced the generic rule that for sales of new generating capacity, an applicant would no longer have to demonstrate an absence of generation market-power as long as the utility and its affiliates: (1) do not have, or have adequately mitigated transmission market power, e.g., by filing a comparable open-access tariff, and (2) do not own or control other barriers to market entry. *Id.* at 61,552. Citing *American Elec. Power Service Corp.* 67 F.E.R.C. ¶ 61,168 (1994) [hereinafter *AEP*], the Commission stated that "an open-access transmission tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system." *Id.* at 61,557. The Commission justified this change by concluding that "we are convinced that if the transmission market power standard is satisfied, and there is no evidence that the seller can erect other barriers to entry into wholesale generation markets, the prospect of entry by other suppliers will check the seller's ability to sustain monopoly prices." *Id.* at 61,552-53.

30. See, e.g., *Heartland Energy Servs., Inc.*, 68 F.E.R.C. ¶ 61,223 (1994) (in which the Commission accepted a power marketer's request to sell electricity at market-based rates commencing on the day that its affiliated utility filed a revised comparability tariff pursuant to *AEP* and *KCPL*).

31. Order No. 888, *supra* note 1, at 31,644.

32. Order No. 888, *supra* note 1, at 31,634. The Commission also noted that a "second critical aspect of the rules is to address recovery of the transition costs of moving from a monopoly-regulated regime" to a competitive bulk power market, and allowed utilities "to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open-access." *Id.* at 31,634-36. While Order No. 888's requirement that utilities provide nondiscriminatory open-access is interrelated with the issue of stranded costs resulting from such open-access, this article focuses solely on the best method of implementing open-access, and therefore does not address stranded cost issues.

file at the Commission; and (2) take transmission service for their own wholesale sales and purchases under their open-access tariff. Order No. 888 contained a *pro forma* open-access tariff that offered both network and point-to-point service, and required all public utilities to make compliance filings under section 206 of the FPA to conform to the non-price terms and conditions of the *pro forma* tariff. In addition, Order No. 888's companion order, Order No. 889, required public utilities to develop and maintain an Open-access Same-Time Information Service (OASIS) to give transmission users the same access to transmission information that the utility enjoys.³³ Order No. 889 also required utilities to comply with prescribed standards of conduct that are designed to prevent the employees of a public utility engaged in the wholesale merchant function from receiving preferential access to any pertinent transmission-related information.

Unlike in the natural gas industry, where the Commission required separate corporate entities for the sale and delivery of natural gas,³⁴ the Commission, through Order No. 888, only required public utilities to "functionally unbundle" their services. In addition to its functional unbundling requirement, the Commission noted that it intended "to accommodate other mechanisms that public utilities may submit, including voluntary corporate restructurings (e.g., ISOs, separate corporate divisions, divestiture, pool costs), to ensure that open-access transmission occurs on a non-discriminatory basis."³⁵ As part of its encouragement of "innovative restructuring proposals,"³⁶ the Commission listed eleven principles it would use to assess ISO proposals.³⁷ However, despite the Commission's statement that it would encourage corporate unbundling proposals, and its enumeration of the eleven ISO principles, the premise of Order Nos. 888 and 889 was that functional unbundling should be sufficient to ensure nondiscriminatory open-access to transmission facilities and information.

33. Order No. 889, *Open Access Same-Time Information System (Formerly Real-Time Information Network) and Standards of Conduct*, F.E.R.C. STATS. & REGS., Regs. Preambles ¶ 31,035, at 31,585 (1996), *order on reh'g*, Order No. 889-A, III F.E.R.C. STATS. & REGS., Regs. Preambles ¶ 31,049, *reh'g denied*, Order No. 889-B, III F.E.R.C. STATS. & REGS., Regs. Preambles ¶ 61,253 (1997).

34. Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, III F.E.R.C. STATS. & REGS., Regs. Preambles ¶ 30,939, at 30,397, 57 Fed. Reg. 13,267 (1992) (codified at 18 C.F.R. pt. 284), *order on reh'g*; Order No. 636-A, III F.E.R.C. STATS. & REGS., Regs. Preambles ¶ 30,950, 57 Fed. Reg. 36,128 (1992) (codified at 18 C.F.R. pt. 284), *order on reh'g*; Order No. 636-B, 57 Fed. Reg. 57,911 (1992) (codified at 18 C.F.R. pt. 284), 61 F.E.R.C. ¶ 61,272, *reh'g denied*; 62 F.E.R.C. ¶ 61,007 (1993) *remanded in part*; *United Distribution Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996).

35. Order No. 888, *supra* note 1, at 31,656.

36. Order No. 888, *supra* note 1, at 31,656.

37. Order No. 888, *supra* note 1, at 31,730-32.

With the conclusion of the ISO Conferences,³⁸ the Commission appears ready to contemplate the next step in its restructuring of the nation's electric industry. The Commission must now consider whether its functional unbundling approach, coupled with its encouragement of ISO formation, is sufficient to attain a competitive electric power industry, or whether it should also offer incentives to utilities to form for-profit regional transmission companies.³⁹

III. CAN BOTH ISOS AND ITCs FACILITATE THE COMMISSION'S GOALS FOR A COMPETITIVE ELECTRICITY MARKET?

A. *The Formation of Independent Transmission Companies*

Industry representatives, along with the Commission, increasingly view a public utility's voluntary transfer of its transmission assets to a for-profit ITC as an alternative to ISO participation and as "a potential strategic response to the global industry-wide forces that are reshaping the electric utility business environment."⁴⁰ A utility may consider divesting its assets for various reasons. In addition to the loss of the assets' strategic value,⁴¹ a transmission-owning utility may incur significant economic and regulatory costs associated with the operational separation of its generation and transmission functions. This separation may result in a decrease in the portfolio value of the utility's combined (e.g., vertically-integrated) assets because of the requirement that the utility separate its transmission and generation employees and facilities. Transmission-only utilities and generation-distribution utilities will not incur these functional separation costs. Therefore, it may be economically advantageous for the

38. In addition to a national conference in Washington, D.C., ISO conferences were held in Portland, Phoenix, Kansas City, Indianapolis, Richmond, New Orleans, and Orlando in the spring and summer of 1998.

39. Hon. Vicky A. Bailey, Comments Before the Washington, D.C. ISO Conf. (Apr. 15, 1998), in F.E.R.C. Docket No. PL98-5-000, at 8-9.

40. Wayne P. Olson & Kenneth W. Costello, *Electricity Matters: A New Incentives Approach for a Changing Electric Industry*, ELEC. J., Jan. - Feb. 1995, at 31.

41. A utility's interest in pursuing its corporate restructuring options is the direct result of the Commission's open-access requirements, under which transmission facilities no longer add "strategic" value to a utility's upstream generation assets or downstream distribution assets. "Strategic" value refers to the historic linkage of the transmission and generation functions by which the utility is able to use its transmission facilities to insulate its generating business from competition. Under the Commission's open-access requirements, transmission assets become "simply another portfolio asset available for use by any eligible customer." Comments on Behalf of Northern States Power Company at the ISO Conf. (Apr. 29, 1998), in F.E.R.C. Docket No. PL98-5-000, at 9 [hereinafter NSP Comments]. However, some commentators note that, even under Order No. 888's open-access environment, transmission's "highest use within a vertically integrated utility is as a shield to protect from competition other parts of the utility's business." Steve Kean, Comments on Behalf of Enron Corp. at the Washington, D.C. ISO Conf. (Apr. 16, 1998), in F.E.R.C. Docket No. PL98-5-000, at 7. Roy Thilly, Comments on Behalf of Wisconsin Public Power, Inc. at the Washington, D.C. ISO Conf. (Apr. 15, 1998), in F.E.R.C. Docket No. PL98-5-000, at 7 (stating that Order No. 888's open-access "tariffs have been a big step forward, but they don't resolve all undue discrimination problems").

utility to pursue various restructuring options after having assessed the economic impact of functionally unbundling.⁴²

A utility may also be reluctant to transfer control of its transmission assets to a non-profit entity such as an ISO, which would result in the separation of the ownership and the operation of the facilities being transferred.⁴³ Unlike an ISO, which merely *operates* the utility's transmission facilities, both the *ownership* as well as the *operation* of the facilities would be unified in an ITC structure.⁴⁴ The transmission-owning utility may be more comfortable transferring those facilities into a for-profit entity whose employees and management have the necessary experience and proper incentives to effectively manage the facilities and whose structure combines both the operation and the ownership of the facilities. At the same time, however, a utility may be extremely cautious about such a radical corporate reorganization as a transfer of its transmission assets into an independent company of which it has no control. Even assuming that a utility considers its core business is essentially generation and transmission is simply a means to connect its generation and load,⁴⁵ such a move requires a complete re-evaluation of the vertically-integrated utility's corporate philosophy.

In addition to these factors, a utility may be reluctant to relinquish control of its facilities to an ISO for fear that its ability to earn its allowed rate of return will be jeopardized. The Commission may view a utility's passive ownership of the transmission facilities that are under the control of an ISO as a lower risk that justifies a lower rate of return.⁴⁶

The ITC concept is based on the premise that if a for-profit company combines the attributes of ownership of transmission facilities with the operation of those facilities, then that company has a greater incentive to improve efficiency and reliability in the provision of transmission services than does a nonprofit ISO. Unlike an ISO, which is responsible for the

42. NSP Comments, *supra* note 41, at 10.

43. "It makes little sense to expect shareholders of equity corporations to remain satisfied with the returns from assets for which the management is delegated to a non-profit corporation." NSP Comments, *supra* note 41, at 10.

44. However, Northern States Power Company (NSP), which discussed its ITC proposal at the Commission's Kansas City ISO conference on May 29, 1998, asserted that an ITC does not necessarily have to own the facilities that it controls. According to NSP, a transmission company may obtain its facilities through a long-term lease arrangement. The main requirement for the ITC should be that it not only operate the transmission facilities (as does an ISO), but that it have "an interest in the operation of the facilities that is akin to ownership." NSP Comments, *supra* note 41, at 18. This means that if the ITC does not own the assets, it should have all of the risks and rewards associated with ownership, including the right to control the facilities, to make capital improvements on the facilities, and to realize profits from the use of the facilities. The purpose of this requirement is to ensure that the ITC has the proper incentives associated with the characteristics of ownership, even if it does not actually own the facilities.

45. For most integrated companies, transmission represents only about ten to fifteen percent of their assets. Doug Dunn, Comments Representing Goldman Sachs Before the Washington, D.C. ISO Conf., (Apr. 15, 1998), in F.E.R.C. Docket No. PL98-5-000, at 14.

46. A representative of NSP has suggested to the authors that this lower risk may result in an earnings loss of two to three percent less than the current rate of return.

short-term reliability of the grid but may have no accountability for long-term reliability or for the grid's efficient management,⁴⁷ a for-profit ITC is responsible to its shareholders and has a more pronounced incentive to operate its system efficiently. An ITC will be able to increase its return by increasing the usage across its system, both in terms of users and the amount of power transmitted. This maximization of system usage should, in turn, lower the cost of transmission for the ITC's customers.

Moreover, ISOs, which are in large part controlled by the traditional elements of the industry, may not be as interested in developing innovative products as are ITCs. ITCs are new market participants and may be more aggressive in seeking new sources of revenue. They may be more responsive to exploring new products for other relatively new market participants, such as power marketers, who will require different transmission services to package with generation.

1. The Application of the Eleven ISO Principles to ITCs

In Order No. 888, the Commission did not mandate corporate unbundling of the utility's generation and transmission assets. However, recognizing that some utilities and tight power pools were indeed exploring the ISO option, even without any Commission requirement to do so, the Commission promulgated eleven principles in Order No. 888, which would be used to assess any future ISO proposals. These eleven principles are:

(1) the ISO's governance structure should be fair and nondiscriminatory;

(2) neither the ISO, nor its employees, should have any financial interest in the economic performance of the ISO or in any market participant;

(3) the ISO should provide open-access to its system and services pursuant to a single, unbundled grid-wide tariff applied in a nondiscriminatory manner;

(4) the ISO should be responsible for short-term reliability of the operation of the grid;

(5) the ISO should control the operation of interconnected transmission facilities within its region;

(6) the ISO should be able to identify and relieve transmission constraints and should have some control over appropriate generation facilities;

(7) the ISO should have the appropriate incentives to operate its system efficiently;

(8) the ISO should have transmission and ancillary services pricing policies which promote the efficient use of and investment in the generation, transmission, and distribution of power;

(9) the ISO should make information regarding the transmission

47. Hebert, *supra* note 5, at 8-9.

system publicly available on an electronic network;

(10) the ISO should coordinate with neighboring control areas; and

(11) the ISO should establish an alternative dispute resolution process.⁴⁸

Commissioner Hebert noted that these principles contain a number of inherent problems that, instead of creating predictability for utilities contemplating ISO filings, may actually impede ISO formation.⁴⁹ He noted that the eleven principles, in imposing on ISOs a management structure in which all classes of users may participate, effectively removed control from any one class, thereby eliminating any standards of accountability.⁵⁰ He also criticized the Commission's principles for eliminating the ISO's profit motive. He stated that while nonprofit "corporations have a place in a capitalist economy [n]o one has made the case for such an arrangement in transmission, a private business that requires large expenditures and risk-taking."⁵¹ Commissioner Hebert concluded that "a totally disinterested management [as mandated by the Commission's eleven principles] deprives the ISO of necessary expertise in fulfilling the goals of maintaining reliability and creating incentives for efficient management of the grid."⁵²

A concern that arises from the application of the ISO principles is whether the Commission will conclude that other models of corporate unbundling conform to their requirements. Specifically, the Commission may be faced with the question of whether its principles preclude the development of ITCs as acceptable independent transmission providers capable of ensuring nondiscriminatory open-access to the nation's grid. In many instances, there is no distinction between the manner in which an ISO or an ITC structure will fulfill the requirements of the ISO principles. The independence requirements (principles 1 and 2) would be equally applicable to ITCs, otherwise an ITC may not be an effective means to mitigate vertical market power to facilitate competition. Because an ITC will have no connection to other market participants, including generators, it can provide open-access, nondiscriminatory transmission services (principle 3). It will also have operational control over interconnected transmission facilities within its region (principle 5). Similarly, an ITC can just as easily develop mechanisms to coordinate with neighboring control areas (principle 10) or establish alternative dispute resolution procedures (principle 11) as can an ISO.

48. Order No. 888, *supra* note 1, at 31,730-32.

49. Hebert, *supra* note 5, at 8.

50. Commissioner Hebert noted that ISOs lack the necessary experience to ensure reliability and create incentives for efficient management. As for the two-tiered system of ISO governance, he stated that "[c]umbersome administration becomes the substitute for ignorance. Giving governance to all classes of participants—transmitters, generators, customers and states—creates paralysis." Hebert, *supra* note 5 at 8-9.

51. Hebert, *supra* note 5, at 9.

52. Hebert, *supra* note 5, at 9.

Principle 4 requires an ISO to ensure the short-term reliability of grid operations, including compliance with the standards of the North American Electric Reliability Council (NERC) and the regional reliability councils.⁵³ An ITC must comply with any applicable reliability criteria and can, therefore, ensure short-term reliability just as effectively as an ISO.⁵⁴ Furthermore, as described below, because an ITC is a for-profit entity that owns its facilities, the ITC can increase long-term reliability by making necessary investments in transmission plant. Because the ISO is a nonprofit organization and cannot produce a return on its investment, it has a more limited incentive to improve its transmission assets. Moreover, any investment in a transmission plant would be cumbersome for the ISO as it would involve coordination with the transmission owners who may be reluctant to make such an investment. An ITC's reliability will be driven in large part by its for-profit status, under which it will provide efficient and reliable service in order to assure customer satisfaction, and thereby increase its system usage and its profits. However, unlike an ISO whose governance structure by definition includes participation by various classes representing all of the users of the transmission system, participation in an ITC's decision-making process is restricted to the company's corporate governance structure. While the ITC's for-profit status offers an incentive to maintain reliability, an ITC will not necessarily have the input from other market participants regarding various reliability issues. Therefore, in order to ensure that an ITC has the appropriate incentives to comply with reliability criteria, the ITC's decision-making process should be structured to allow input from other market participants concerning these reliability issues (principle 1).

An ITC will also be capable of identifying and relieving transmission constraints (principle 6). Indeed, given its profit motivation and need to maximize the usage of its system, an ITC may have more incentive than an ISO to relieve constraints. Similarly, an ITC may have a stronger incentive than an ISO to establish an effective electronic communications and information network, thus satisfying principle 9.

Because an ITC is a profit-driven entity, it will have the appropriate incentives to efficiently manage and operate its system (principle 7). As long as the ITC is sufficiently independent from the divesting utility's shareholders, who own generation or distribution, this condition is met. In fact, given that an ISO is a nonprofit entity whose organization is structured to *simulate* the incentives of the free market while an ITC's operations are *truly* market-driven, an ITC should logically promote efficiency more effectively than an ISO.

53. NERC is charged with the task of promoting the reliability for the electricity supply in North America.

54. NSP has stated that it believes that there will be a continuing role for NERC and the regional reliability councils, and that various market participants can provide input on reliability issues through these organizations. Anthony G. Shuster, Comments on Behalf of Northern States Power Co Before the ISO Conf. (May 29, 1998), in F.E.R.C. Docket No. PL98-5-000, at 115.

Principle 8 states that an "ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption."⁵⁵ While transmission costs represent only about two percent of the operating expenses of major investor-owned utilities, transmission pricing is, nonetheless, important because it creates efficiencies in the generation market.⁵⁶ For example, transmission prices, if correctly calculated, send signals to add transmission capacity, or generation, or where to locate future load. Adding transmission capacity to relieve transmission constraints can allow high-cost generation to be replaced by less expensive generation, which results in savings to consumers. Also, a well-structured transmission tariff can eliminate "pancaked" prices, lower transmission costs, and open a region to increased competition.⁵⁷

Therefore, the question of whether an independent transmission provider's pricing policies promote efficiency is of prime consideration in the ISO/ITC debate. Critics have argued that because an ISO is a market-neutral entity, it will have "no natural institutional incentive whatsoever to affirmatively 'promote' any objective or policy."⁵⁸ This criticism strikes at the heart of whether transmission pricing should "promote" efficiency in generation and consumption. They question whether an ISO or an ITC should be charged with such promotion. Rather, fairly and accurately priced transmission service may well be most efficient when the pricing follows well-established principles of cost causation. The question of where to locate new generation and whether load management is economically efficient should be decided in the context of nondiscriminatory transmission prices. This approach is consistent with the basic premise of market-based pricing; namely, that regulators should influence economic decisions only where necessary to correct for market power.

Given this review, it appears that the eleven ISO principles are in large part equally applicable to ITCs. Indeed, because of the incentives derived from their for-profit status, as well as the fact that ownership and control are unified in a for-profit transmission company, ITCs may be better able to achieve the goals embodied in these principles.

2. Specific ITC Proposals

Because no utility has yet filed an ITC proposal with the Commission, it should be emphasized the proposals discussed herein are preliminary, and are subject to significant change as the interested utilities investigate their various restructuring options. Although each ITC's corporate structure would be uniquely designed to take into account the specific

55. Order No. 888, *supra* note 1, at 31,732.

56. EIA July 1998 Report, *supra* note 25, at 40.

57. EIA July 1998 Report, *supra* note 25, at 40.

58. Post-Conference Comments of the Gridco Commenters (May 1, 1998), *in* F.E.R.C. Docket No. PL98-5-000, at 15.

circumstances of the entities and assets involved, each company would necessarily be organized to preclude the utility from exercising control over the ITC.⁵⁹

NSP, for example, is considering a proposal under which it and other transmission-owning utilities would spin-off the stock in their newly-created transmission companies to their shareholders on a *pro rata* basis.⁶⁰ The sole assets of those new companies would be the transmission assets that were formerly owned by the utilities. These companies (which NSP refers to as Transcos) would form a limited liability corporation (LLC) (which NSP refers to as an ITC), which would operate and control the transmission assets. According to NSP, the LLC would provide transmission services, develop pricing for its services, plan and implement any additions and improvements in the system. The Transcos may at some point reevaluate whether it would be in their best interests to dissolve the LLC and merge into one publicly-owned corporation. NSP reports the use of the LLC as the organizing entity is dictated by tax considerations. NSP's tax advisors inform the company that an immediate merger of the Transcos into a single corporate entity would constitute a taxable transaction for federal income tax purposes and thus would be detrimental from the standpoint of NSP's current shareholders. The tax advisors also report this adverse tax consequence would likely be present for any coordinated spin-off by utilities followed by an immediate merger of the new entities into one independent transmission company.

At the Commission's April 16, 1998, ISO Conference held in Washington, D.C., Entergy Services Inc. (Entergy) unveiled its own transmission company proposal. Like the NSP concept, Entergy's proposal would create a Commission-regulated, for-profit company that would operate independently of Entergy. Unlike the NSP proposal, Entergy's transmission company would remain affiliated with Entergy. As currently envisioned, Entergy's transmission assets and employees engaged in transmission functions would be transferred to the new entity, while the new company's stock would remain with Entergy. The voting rights associated with that stock would be transferred to a trust, with an independent trustee.⁶¹ An independent, non-stakeholder board, which would be chosen by the trustee and approved by the Commission, would

59. See the discussion above regarding the eleven ISO principles and their applicability to ITCs.

60. This description of the NSP proposal was provided to the authors by NSP.

61. Entergy representative Frank Gallagher stated that Entergy had chosen to use an independent trust, rather than transfer the shares of the new company to the Entergy shareholders, because Entergy wanted to retain its ability to earn a return on the transmission assets. However, as discussed below, the spin-off of a subsidiary into a new entity may be structured to allow the shareholders of the parent company to continue to earn a return on the assets in that they would receive shares in the newly-formed company. The Entergy proposal assumes that the Commission would accept the independent trustee structure as establishing a sufficient degree of separation between Entergy's generation and distribution assets. Mr. Gallagher also noted that he suspects that the Entergy transmission company would be publicly traded at some point. Frank Gallagher, Comments on Behalf of Entergy Services, Inc. Before the New Orleans, L.A. ISO Conf. (June 1, 1998), in F.E.R.C. Docket No. PL98-5-000, at 66.

be responsible for the operation of the transmission assets. Despite Entergy's continued ownership of the new company's stock, the trustee, through its exercise of the voting rights associated with the stock, would ensure Entergy could not exercise any control over the new company's assets. The employees of the new company would be subject to strict conflict of interest standards and would receive compensation and incentives tied only to the new company's performance.

Entergy's proposal contemplates that other transmission owners would be willing to commit their transmission assets and employees to the enterprise, thereby increasing the size of the company. However, the Entergy plan raises a number of concerns with regard to the company's potential for expansion. First, it is questionable whether another utility would even be interested in transferring its transmission assets to an affiliate of Entergy, despite the fact that the voting rights associated with the new company's stock would be vested in an independent trustee. Entergy may be a competitor of that utility in the generation market, and the utility may fear that Entergy would be able to use the strategic value of the utility's transmission assets once the assets have been transferred to the new company, to the benefit of Entergy's own generation.⁶² Second, if another utility has transferred its assets to the Entergy affiliate, it is unclear what corporate relationship that utility would then have with the newly-formed transmission company. Finally, it remains unclear whether and under what circumstances Entergy may choose to dismantle the transmission company in the future, and how this possibility might affect the willingness of other utilities to transfer their transmission assets into the new company.⁶³ Once Entergy has provided more details on its proposal, it is likely many of these questions will be answered.

Entergy has described the advantages of its ITC proposal as follows:

While this company would provide non-discriminatory transmission access, it would also be driven, through appropriate incentives, to minimize costs, maximize throughput, achieve efficient levels of congestion and reliability, and expand the transmission grid when economically justified. Unlike a not-for-profit ISO, the alternative structure will retain the efficiencies gained by integrating the operation of the system with the maintenance, engineering, construction and restoration of that same system. Having the asset management portion of the transmission business working in tandem with, answering to the same management team, and driven by the same incentives as the operational portion of the business will ensure that the system is operated, maintained and expanded in the most efficient manner. While a not-for-profit ISO can develop administrative protocols among many transmission owners to address such issues, Entergy believes that these

62. Robert D. Priest, Comments on Behalf of Public Service Commission of Yazoo City, Miss. Before the Yazoo City, Miss. ISO Conf. (June 1, 1998), *in* F.E.R.C. Docket No. PL98-5-000, at 127, stating that "I don't know if a trustee guarantees independence. If it's a Transco that's a hundred percent owned by one utility, then all the employees at that Transco know and understand how they're impacting the bottom line of their own. So I think it's a little bit more of a problem to establish independence than just having a trustee vote the stock."

63. Presumably, only the independent trustee would have the right to dismantle the company.

administrative relationships will be a poor substitute for the synergies available through a single for-profit company.⁶⁴

Although the details of each ITC proposal will necessarily be specific to the utility or utilities involved, Entergy's description of its proposal accurately captures the benefits many observers see in for-profit transmission companies.

The differences between the Entergy and NSP proposals are significant. While the NSP concept envisions a full corporate divestiture, Entergy hopes to retain an affiliate relationship with its planned transmission company. These different approaches to the formation of transmission-only companies suggest the wide array of options that utilities are currently considering as alternatives to ISOs. Although these two proposals are currently the most publicized approaches, the discussions among the various market participants at the regional ISO conferences indicate the serious consideration that the industry is currently giving to ITCs.⁶⁵ Given the diversity of restructuring concepts now being considered by public utilities as alternatives to ISO participation, we think the Commission should remain open to various proposals as long as the models ensure nondiscriminatory access to transmission facilities and information.

3. The Spin-off of Transmission Assets to an ITC

NSP's proposal is premised on the "spin-off" of assets into a new corporate entity. Given the potential tax benefits from such a transaction, as noted below, other ITC proposals may follow this approach. Although a discussion of the requirements and implications of a valid spin-off transaction is beyond the scope of this article, a cursory review of this type of reorganization is helpful in understanding a utility's incentives for divesting its transmission assets. Any utility considering divesting its transmission assets would be well-advised to obtain tax counsel to determine the implications of its spin-off plan.

A spin-off is a corporate reorganization in which a parent corporation distributes the stock of its subsidiary to the shareholders of the parent. As is the case with the NSP proposal, the subsidiary to be spun-off can be formed by the parent's assets specifically to effectuate the asset transfer.⁶⁶ Under a spin-off transaction, "the original corporation transfers part of its assets to a new corporation in exchange for the latter's shares and then immediately distributes such shares to the original corporation's shareholders, without the surrender by them of any of their shares in the

64. Comments of Entergy Services, Inc. Before the ISO Conf. (May 1, 1998), in F.E.R.C. Docket No. PL98-5-000, at 127.

65. See generally Indianapolis, Ind. ISO Conf. (June 4, 1998), in F.E.R.C. Docket No. PL98-5-000, at 62-86; New Orleans, L.A. ISO Conf. (June 1, 1998), in F.E.R.C. Docket No. PL98-5-000, at 16-79; Kansas City, Mo. ISO Conf. (May 29, 1998), in F.E.R.C. Docket No. PL98-5-000, at 74-134.

66. Robert A. Jacobs, *The Anatomy of a Spin-Off*, 1967 DUKE L.J. 1, 7 (1967) [hereinafter Jacobs].

original corporation.”⁶⁷ After a spin-off, the shareholders of the parent own shares in both the parent and the new company. Entergy’s proposal does not envision a spin-off because Entergy will retain the shares of the new transmission company.

If a spin-off is correctly structured under section 355 of the Internal Revenue Code, the transaction will not result in any tax liability to the parent corporation, the subsidiary, or the shareholders of the parent corporation.⁶⁸ Section 355 provides that such tax exempt treatment is available if the following conditions have been met: (1) the parent must distribute stock in a “controlled” corporation (control is defined as the ownership of stock representing at least eighty percent of the voting power and at least eighty percent of the total shares of all other classes of stock);⁶⁹ (2) the distribution cannot simply be a “device” by the parent to distribute earnings and profits to its shareholders on a tax-free basis;⁷⁰ (3) both the parent corporation and the new entity must continue to operate as separate active trades or businesses immediately after the distribution;⁷¹ and (4) the parent corporation must distribute all of the stock of the subsidiary or an amount of stock equal to the effective control of the subsidiary.⁷² A corporation contemplating a spin-off of assets under section 355 will generally seek a private letter ruling from the Internal Revenue Service before undertaking the reorganization in order to avoid “the potentially catastrophic tax costs of a failed section 355 transaction.”⁷³

It is axiomatic that the management of a company has a fiduciary duty to the company and to its shareholders. No utility management would be willing to divest its transmission assets unless it first determined it would be in the best interest of the utility to do so, and its shareholders would not be harmed by such a transfer. A spin-off is a form of corporate reorganization that allows a utility to divest its assets while allowing the shareholders to retain an interest in those assets.⁷⁴ With a spin-off of transmission assets to an ITC, the shareholders may be able to maximize this interest through incentive-based rates, as discussed in detail below. Therefore, a transfer under section 355 may offer an appealing option for a utility seeking to transfer the ownership and control of its transmission

67. HARRY G. HENN, *LAW OF CORPORATIONS*, 735 (2d ed. 1970).

68. 26 U.S.C. § 355 (1998). “Section 355 provides for the separation of one or more businesses formerly operated, directly or indirectly, by a single corporation into two or more corporate entities without the shareholder being required to recognize gain or loss with respect to stock distributed in connection with the separation process.” Jacobs, *supra* note 66, at 2.

69. 26 U.S.C. § 355(a)(1)(A) (1998). See also 26 U.S.C. § 368(c) (1994).

70. 26 U.S.C. § 355(a)(1)(B) (1994). This device test is necessarily a subjective analysis. John R. Wilson, *A New Spin on Corporate Spin-offs: Rev. Proc. 96-30*, 25 *COLO. LAW.* 109 (Oct. 1996) [hereinafter Wilson].

71. 26 U.S.C. § 355(b)(1) (1994).

72. 26 U.S.C. § 355(a)(1)(D) (1994). For a description of these requirements generally, see Jacobs, *supra* note 66, at 6-22.

73. Wilson, *supra* note 70, at 109.

74. As described above, a vertically-integrated utility may determine that it is uneconomical to retain its transmission assets because of the requirements of functional unbundling.

assets, while at the same time interested in preserving the value of those assets for its shareholders.

4. The Commission's Authority To Approve a Transfer of Transmission Assets

Although the Commission has never considered a utility's transfer of transmission facilities to an independent entity, it would likely review such a proposal under its authority granted under section 203 of the FPA.⁷⁵ Section 203 provides that the Commission will approve a transfer of jurisdictional assets if such disposition is "consistent with the public interest."⁷⁶ Generally, this public interest standard is met if, when viewing the proposal as a whole, the probable benefits of the transaction outweigh its costs.⁷⁷ On December 30, 1997, the Commission issued its Merger Policy Statement in which it revisited its analysis of the section 203 public interest standard in light of the recent changes in the electric utility industry.⁷⁸ Although the Merger Policy Statement focuses specifically on mergers, it does provide some guidance as to how the Commission may apply the public interest standard to other transactions that require the Commission's section 203 approval, including a transfer of transmission assets to an ITC. In its Merger Policy Statement, the Commission determined that its revised public interest analysis under section 203 would take into account the following three factors: (1) the transaction's effect on competition; (2) the transaction's effect on rates; and (3) the transaction's effect on regulation.⁷⁹

75. In addition to the Commission's section 203 authority, the Commission recently granted a petition for a declaratory order filed by Citizens Utilities Co. (Citizens) seeking a determination that its proposed spin-off of various subsidiaries did not violate section 305(a) of the FPA. *Citizens Utils. Co.*, 84 F.E.R.C. ¶ 61,158 (1998). The Commission agreed with Citizens that a review under section 203 was not appropriate because Citizens proposed to spin-off its communications subsidiaries, which did not involve jurisdictional assets subject to the Commission's section 203 authority. Section 305(a) prohibits "the making or paying of any dividends . . . from any funds properly included in capital account." 16 U.S.C. § 825(d) (1994). Citizens proposed to transfer its communications subsidiaries to a new corporation and to distribute the stock in the new entity to Citizens' existing shareholders and sought from the Commission an order that this proposal did not violate section 305(a). The Commission held that, although neither the FPA nor the Natural Gas Act defined the term "dividends," the proposed spin-off did not involve dividends because "the proposed separation will have no adverse effect on the value of shareholders' interests. Shareholders will have the same ownership interests after the separation as before, it will simply be ownership of stock in two companies rather than one." *Citizens* indicates that section 305 should not constitute a barrier to a transfer of transmission assets to an ITC.

76. 16 U.S.C. § 824b(a) (1994). Facilities used for the transmission of electric energy in interstate commerce are jurisdictional facilities under section 201 of the FPA, 16 U.S.C. § 824 (1994), and therefore the transfer of such facilities is subject to section 203.

77. *Northeast Utils. Serv. Co. v. FERC*, 993 F.2d 937, 945 (1st Cir. 1993).

78. Order No. 592, *Policy Statement Establishing Factors the Commission Will Consider in Evaluating Whether a Proposed Merger Is Consistent with the Public Interest*, III F.E.R.C. STATS. & REGS., Regs. Preambles ¶ 31,044 (1997) [hereinafter Merger Policy Statement].

79. Having analyzed the three factors used to determine whether a proposed transfer is consistent with the public interest, the Commission may also exercise its implied authority under section 203 to condition its approval of a proposed disposition of assets that does not otherwise meet the public interest standard. *Utah Power & Light Co.*, 45 F.E.R.C. ¶ 61,095, at 61,280 (1988).

By concluding in Order No. 888 that it would encourage corporate unbundling proposals, the Commission indicated its willingness to consider a variety of models for separating transmission from generation. Because the Commission signaled its receptiveness to proposals for corporate divestiture that will mitigate vertical market power and further the Commission's goal of fostering a competitive market by separating the generation and transmission functions, it is unlikely the Commission would determine that an ITC proposal would have a negative impact on competition.

In its Merger Policy Statement, the Commission concluded that it will review whether a section 203 application contains adequate "ratepayer protection," given the specifics of the proposal.⁸⁰ Consequently, a utility proposing to spin-off its transmission assets to an ITC will bear the burden of demonstrating that the customer will be protected from any adverse rate changes resulting from the proposed disposition. Unlike in a section 205 proceeding, where proposed rates are only approved if they are found to be just and reasonable, in a section 203 proceeding, the Commission will only require a generalized demonstration of possible savings and efficiencies resulting from the proposed transaction.

As discussed in the following section, an ITC proposal may include a request for the Commission's approval of incentive-based rates, which are based on the expectation that a utility's ability to make a profit through its efficiencies will drive costs down and lead to lower rates. Assuming the Commission approves such a rate plan for an ITC, that approval should constitute a Commission determination that the formation of the ITC will not have a negative impact on rates under the public interest analysis. However, in its Commission's Policy Statement on Incentive Regulation, the Commission stated that it will require any incentive-based rate proposal to share any of the resulting cost efficiencies with the utility's wholesale customers.⁸¹ Thus, a Commission finding of no negative impact on rates may be conditioned on a mechanism that requires the ITC to share any cost savings with its customers.

Finally, the public interest standard requires a determination that the proposed transaction will not create a "regulatory gap" that would impair the effectiveness of regulation by the Commission and by the appropriate state regulatory authorities over the entity.⁸² Concern regarding the effect of a transfer of FERC-jurisdictional assets on regulation would not appear to present a valid objection to a utility's request for authority to transfer assets to an ITC. The ITC will be a FERC-jurisdictional entity and will not have any associated companies.⁸³ There is, therefore, no danger that the

80. Merger Policy Statement, *supra* note 78, at 30,122.

81. *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities*, 61 F.E.R.C. ¶ 61,168 (1992) [hereinafter Policy Statement].

82. *Id.* at 30,124. See also *Cincinnati Gas & Elec. Co.*, 64 F.E.R.C. ¶ 61,237, at 62,710 n.278 (1993) (citing to *Commonwealth Edison Co.*, 36 F.P.C. 927, at 936-42 (1966), *aff'd sub nom.*, *Utility Users League v. FPC*, 394 F.2d 16 (7th Cir. 1968), *cert. denied*, 393 U.S. 953 (1968)).

83. This assumption may not be true for the Entergy proposal. It remains unclear what

ITC will fall into a "regulatory gap." In addition, the state regulatory authorities will continue to have an effective voice in regulation of the ITC through interventions in Commission proceedings and potentially through the state siting authority. Moreover, any loss of jurisdiction of state regulatory authorities will occur whether the utility transfers assets to a new transmission entity or the utility joins an ISO.

5. Performance-Based Ratemaking as an Incentive To Form ITCs

Despite the Commission's functional unbundling requirements, some observers claim that utilities are still able to take advantage of the "strategic" value of their integrated assets and manipulate their transmission facilities to the advantage of their own generation.⁸⁴ Assuming this strategic advantage exists, utilities may require some incentive to relinquish control over their transmission assets. Instead of using the "stick" of mandatory ISO participation,⁸⁵ the Commission may consider offering a "carrot" in the form of performance-based ratemaking (PBR) authority for the newly-formed transmission company.⁸⁶ The prospect of incentive-based or performance-based rates offers an attractive method of encouraging utilities to assess their various restructuring options.

A utility considering transferring its assets to an ITC will want to preserve or increase the value of those assets for its shareholders. A major incentive for a utility contemplating whether to divest its transmission assets is the possibility of obtaining PBR authority for the newly-formed transmission company. Under PBR, unlike the traditional cost-of service (COS) ratemaking methodology used by the Commission, the utility has the opportunity to increase returns to its shareholders if it can reduce its

relationship Entergy will have with the transmission-only company.

84. Steve Kean, Comments on Behalf of Enron Corp. Before the ISO Conf. (Apr. 16, 1998), in F.E.R.C. Docket No. PL98-5-000, at 3. See also *Morgan Stanley Capital Group v. Illinois Power Co.*, 83 F.E.R.C. ¶ 61,204 (1998).

85. The Commission grounded its authority to order utilities to file open-access tariffs on sections 205 and 206 of the FPA. Order No. 888, *supra* note 1, at 31,699. Indeed, the Commission stated in Order No. 888 that it not only has the authority, but also the "responsibility" to require open-access tariffs "if we find such order necessary as a remedy for undue discrimination." Order No. 888, *supra* note 1, at 31,699. Order No. 888 also explicitly left open the possibility that, if the functional unbundling requirement proved to be ineffective in assuring open-access, the Commission may consider a more "intrusive" approach, such as requiring ISO participation. Order No. 888, *supra* note 1, at 31,699. If the Commission were to now determine that it is time to go beyond merely encouraging ISOs and actually mandate them, it would likely base its authority for such a decision on the same rationale as it used in promulgating Order No. 888; namely, sections 205 and 206 of the FPA. Assuming that the Commission does have the broad authority under sections 205 and 206 to mandate ISO participation through a general rulemaking process, however, it seems unlikely to do so at this time. Given that Order Nos. 888 and 889 are currently on appeal, the Commission would be hesitant to conclude that its restructuring efforts thus far have failed to produce their desired results. As discussed below, the Commission is more likely to require ISO participation in a section 203 merger proceeding or as a remedy for specific instances of discrimination.

86. This article will refer to performance-based ratemaking and incentive-based ratemaking (or incentive ratemaking) interchangeably.

costs.

PBR is an alternative ratemaking methodology by which the regulator determines the rates a company may charge its customers while at the same time allowing the company to profit by eliminating the inefficiencies inherent in COS ratemaking. Traditionally, the Commission used COS regulation to design rates so the utility recovers the cost of its service plus a return on equity.⁸⁷ Although the Commission has the authority to disallow the recovery of imprudently incurred costs,⁸⁸ it is well-accepted that COS ratemaking does not encourage utilities to operate efficiently.⁸⁹ The premise of PBR, which is increasingly being used and considered by utilities as "part of a strategy for transitioning to a competitive marketplace,"⁹⁰ is that if a utility is able to operate more efficiently and reduce operating costs, its shareholders should be able to retain at least a portion of any such cost savings. Likewise, if a utility's performance deteriorates, its shareholders will be penalized. The utility's profits can be higher or lower depending on how efficiently it plans and manages its system.

a. The Commission's Policy Statement on Incentive Regulation

On October 30, 1992, the Commission issued a Policy Statement on Incentive Regulation (Policy Statement) for interstate natural gas pipelines, oil pipelines, and electric utilities.⁹¹ The Policy Statement was issued in response to a Notice of Proposed Policy Statement (NPPS) issued on March 13, 1992.⁹² Recognizing that COS regulation does not encourage long-term efficiency because it does not reward utilities that act aggressively to cut costs and does not penalize utilities for excessive spending, the Policy Statement concluded that it "will allow utilities to propose incentive rate mechanisms as alternatives to traditional cost-of-service regulation."⁹³ The Commission explained that long-term efficiency

87. The Commission is not required to use any specific methodology to determine whether rates are "just and reasonable." *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923).

88. 16 U.S.C. § 824d(a) (1994).

89. "Under most current regulation, a utility's return on a highly successful investment is exactly the same as that earned on a non-productive facility whose costs were 'prudently incurred.'" James Brew, *Moving Toward More Ratemaking Incentives*, ELEC. J. Dec. 1992, at 16, 18 (footnote omitted).

90. MHB CONSULTANTS, INC., *PERFORMANCE BASED REGULATION: DESIGN AND IMPLEMENTATION STRATEGIES 1* (1996) (prepared for Edison Elec. Inst.) [hereinafter EEI Report]. The EEI Report uses information, obtained with interviews from utilities that have implemented or are considering a PBR structure, to assess their experiences in the transition from various COS based rates to PBR. While the "purpose of this report is to identify the 'critical factors' that can make the differences between success and failure in the transition to a PBR," *id.* at 5, the report does not identify which utilities or state commissions have reached which conclusions or results presented in the report.

91. Policy Statement, *supra* note 81.

92. *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Notice of Proposed Policy Statement on Incentive Regulation*, 58 F.E.R.C. ¶ 61,287 (1992) [hereinafter NPPS].

93. Policy Statement, *supra* note 81, at 61,587.

can be achieved by: “(1) divorcing rates from the underlying cost-of-service, (2) lengthening the period between rate cases, and (3) sharing the benefits of cost savings between consumers and stockholders on a current basis.”⁹⁴ The Commission listed the following five standards to which every incentive rate proposal must conform:

- (1) the PBR mechanism must be prospective;
- (2) the utility’s participation in a PBR program must be voluntary;
- (3) the PBR mechanism must be understood by all of the parties involved;
- (4) the benefits to the consumers resulting from the PBR mechanism must be quantifiable; and
- (5) the utility’s PBR proposal must specify how it will maintain its quality of service.⁹⁵

In a lengthy concurrence to the NPPS, Commissioner Trabant questioned whether the Commission’s proposed policy should be applied to wholesale electric services as well as to the transportation and related services of interstate pipelines. He noted “it is not clear if or how incentive ratemaking would apply to our jurisdictional electric areas, such as transmission services and bulk power sales” and he encouraged the Commission “to assess more specifically what exact electric utility services subject to our jurisdiction would be candidates for incentive ratemaking, for what reasons, with what objectives and with what particular incentive approach.”⁹⁶ Commissioner Trabant reasoned that most of the revenue received by electric utilities is not subject to the Commission’s jurisdiction, and the Commission’s primary concern with the electric industry (at the time it issued the NPPS) was to encourage competition in those areas in which it did have jurisdiction, thereby diminishing the need to assess the advisability of any additional alternatives to COS regulation. He concluded:

Consequently, I believe the Commission should concede that few electric jurisdictional areas will be subject to traditional regulation, in whole or in part. Thus, by and large, areas accounting for very little revenue will remain subject to cost-based ratemaking in the face of the competitive policies in electricity.⁹⁷

Various commenters to the NPPS also expressed similar concerns regarding the proposed application of incentive-based rates to electric utilities. The National Rural Electric Cooperative Association (NRECA) argued that it was premature for the Commission to propose incentive-based rates for electric utilities because of pending legislation regarding the nature of competition in the electric industry. The NRECA further argued that, given that PBR is only effective if it results in an actual change in the utility’s behavior, PBR should only be adopted, if at all, for those

94. Policy Statement, *supra* note 81, at 61,588.

95. Policy Statement, *supra* note 81, at 61,598-601.

96. *City of Emporia*, 58 F.E.R.C. ¶ 61,267, 61,907 (1992).

97. *Id.*

companies that are primarily FERC-jurisdictional. The NRECA noted that because the Commission only regulated a small portion of a vertically-integrated electric utility's sales, the imposition of incentive rates on a utility would not affect the utility's behavior, and therefore incentive ratemaking was not warranted.⁹⁸ Similarly, the Chemical Manufacturers Association expressed its concern that, as long as a utility could obtain COS rates from its retail customers and incentive rates from its wholesale customers, there would be significant opportunities for the utility to game the system.⁹⁹

Despite these arguments, the Commission concluded that the general principles outlined in its Policy Statement would apply to wholesale electric service, as well as to gas and oil transportation. The Commission noted that "[w]hile these concerns suggest that the opportunities for incentive regulation in electricity may be relatively limited *at present*, nonetheless, if a utility volunteers a program that benefits both ratepayers and the utility, approval would be warranted."¹⁰⁰ The Commission concluded:

The comments have not convinced the Commission that it should exclude any of these kinds of utilities. Rather, the Commission continues to believe that the principles set forth here are valid guidelines for all these kinds of utilities to construct incentive regulation plans. However, the Commission is aware that special circumstances in each industry vary the efficiencies they can expect to accomplish with incentive regulation.¹⁰¹

The concept of ITCs as a means of completing the transition to a seamless open-access transmission network had not yet emerged by the time the Commission first announced its incentive rate policy in 1992. Even assuming the various concerns raised were valid at the time, they do not now appear to be relevant to the application of PBR to an ITC's transmission facilities. Application of PBR to an ITC, which by definition provides only transmission service and does not own any generation or distribution assets, would not encourage or even allow cost-shifting to retail customers. All of the ITC's sales would be derived from the provision of transmission services. Its behavior therefore can more easily be affected by PBR than a traditional vertically-integrated utility whose wholesale transmission sales are a small percentage of its overall revenues. Moreover, since an ITC would be a monopoly provider of essential services, initially its rates will need to be regulated to prevent an exercise of market power. Thus, contrary to former Commissioner Trabandt's observation, an ITC would be an electric industry service not appropriately governed, at this time, by market-based rates.¹⁰² Under the current

98. Initial Comments of NRECA (Apr. 27, 1992), in F.E.R.C. Docket No. PL92-1-000.

99. Initial Comments of the Chemical Manufacturers Assn. (Apr. 27, 1992), in F.E.R.C. Docket No. PL92-1-000, at 12.

100. *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities*, 61 F.E.R.C. ¶ 61,168, at 61,610 (1992). (emphasis added).

101. *Id.* at 61,588.

102. The time sensitive qualification of the appropriateness of market-based rates is premised on

structure of the electric industry, the ratemaking principles set forth in the Commission's Policy Statement should apply equally to the provision of electric transmission service by an ITC.

On January 31, 1996, the Commission issued a Statement of Policy and Request for Comments (Revised Statement) in response to requests by natural gas pipelines for approval of rates based on pricing methodologies other than traditional cost-based pricing.¹⁰³ While the Commission's Revised Statement established a framework for entertaining various alternative ratemaking proposals *specifically by natural gas pipelines* (including market-based rates, negotiated/recourse rates, and incentive rates), it also provides some additional guidance as to the Commission's views on incentive-based rates that can generally be useful in determining how the Commission may apply incentive regulation to an ITC's rates. In its Revised Statement, the Commission made certain modifications to the PBR standards enunciated in its original Policy Statement. First, the Commission concluded it would not require a pipeline to quantify the benefits of its proposal to the pipeline's customers.¹⁰⁴ Second, although the Commission's expectation was that incentive-based rates should drive industry costs down, it would not require an affirmative showing that the PBR proposal necessarily would result in rates less than what they would have been under COS regulation. Third, the Commission required that any pipeline filing a PBR proposal include a mechanism for sharing its savings with its customers and a method for evaluating its proposal. Finally, while the Commission did not impose a generic standard requiring that all incentive-based proposals be operative for a certain period of time, the Commission determined it would require a commitment from the pipeline to continue to operate under an incentive-based structure long enough to ensure the pipeline was not shifting in and out of the program in order to game the system.¹⁰⁵

Thus far, no electric utilities or gas pipelines have applied for PBR authority under the Commission's Policy Statement (or under the Revised Statement).¹⁰⁶ Nevertheless, it is against this backdrop that the application of PBR to ITCs should be viewed.

the authors' awareness that the development of a robust secondary market in transmission service could constitute grounds to introduce market-based transmission pricing. *Notice of Proposed Rulemaking, Regulation of Short-Term Natural Gas Transportation Service*, 84 F.E.R.C. ¶ 61,085, 63 Fed. Reg. 42,982 (1998) (to be codified at 18 C.F.R. pts. 161, 250).

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

104. *Id.* ¶ 61,238.

105. *Id.*

106. In his recent article, Commissioner Hebert concluded that pipelines have not sought incentive-based ratemaking authority because the pipeline industry has already reduced expenses as far as reasonably can be expected. Hebert, *supra* note 5, at 20.

b. How Does Performance-Based Ratemaking Operate?

There are various PBR options available to an ITC. In its Policy Statement, the Commission noted that a utility is free to propose whatever incentive mechanism it wishes, as long as that mechanism meets the Commission's standards for alternative ratemaking.¹⁰⁷ In its survey of various PBR plans, the EEI concluded "[t]here is no 'ideal' PBR structure or pressure to use a common framework. Success of a PBR program is not tied to any single design feature."¹⁰⁸ The EEI also concluded a utility should not feel compelled to adopt a model in its entirety but may select and mix the attractive components of other existing or proposed PBR plans when putting together its own proposal.¹⁰⁹

c. Indexed Mechanisms –The Rate Cap

Because of the required notice and typical suspension periods for a proposed rate increase, a utility cannot immediately raise its rates if it finds its costs are rising.¹¹⁰ This delay ensures a utility will benefit from any short-term efficiency gains, thereby providing the utility with an incentive to be efficient even without the benefit of incentive-based rates. If the utility's productivity increases, its shareholders can also reap the benefits of the increased revenue if the utility chooses *not* to file a rate case. This "regulatory lag" provides the utility with an incentive to be efficient in the short-term because any savings achieved between rate cases will accrue to the shareholders.¹¹¹ However, the long-term effects of this incentive are diminished by the fact that such benefits will be allocated to the utility's ratepayers in the form of lower rates in the next rate case.¹¹² As a result, a common theme of the various PBR mechanisms is to extend the time period between a utility's rate cases to give the utility an incentive to design and implement programs to increase long-term efficiency, and thereby reward its shareholders for any efficiency gains.¹¹³ This extension generally is achieved by tying the utility's rates or revenues to an outside index, which is based on factors beyond the utility's control.

A common PBR mechanism is the indexed price cap, in which an upper limit is placed on the utility's rates. The appropriate level of rates (also referred to as the baseline rates) as well as the corresponding index mechanism are established at the time the utility's incentive plan is placed

107. Policy Statement, *supra* note 81, at 61,101.

108. EEI Report, *supra* note 90, at 9.

109. EEI Report, *supra* note 90, at 9.

110. FPA § 205(d)-(e). 16 U.S.C. § 824d(d)-(e) (1994).

111. Policy Statement, *supra* note 81, at 61,588.

112. Policy Statement, *supra* note 81, at 61,588.

113. Tim Woolf & Julie Michals, *Performance-Based Ratemaking*, ELEC. J., Oct. 1995, at 64 [hereinafter Woolf & Michals].

into effect. The utility's rates do not remain static between formal rate proceedings, but change automatically, generally on an annual basis, according to a predetermined index. The index takes into account such factors as inflation and productivity increases. Under a rate cap, the utility's profits will depend on ability to increase its sales as well as its success in implementing internal cost-cutting measures.¹¹⁴ The regulatory lag between rate cases is extended in order to give the utility an opportunity to benefit from its efficiency. To the extent that the ITC can keep its costs below the cap, it is entitled to keep the difference as profits (subject to the provisions of any applicable sharing mechanism, as discussed below). If costs rise above the cap, its profits will decline.¹¹⁵

d. Calculating The Applicable Baseline And Index

An indexed rate cap requires the calculation of an applicable starting point and an index to which the utility's rates are linked. Such calculations should be made at the outset of PBR plan implementation. Under the price cap, for example, a utility's base rate will "be the anchor or starting point for future values trended with the index of the mechanism."¹¹⁶ There are two methods for determining the baseline rate for purposes of designing a PBR mechanism. First, the utility's baseline rate can be derived from the company's historical data and projected estimates of variable operating costs in the same way the company's rate base is determined under COS regulation. Under this method, the Commission's concerns will be similar to its concerns under COS regulation; namely, whether the utility is inflating its costs and whether the ratepayers are understating the utility's costs. Second, an appropriate benchmark for the utility may be determined by examining the utility's data within the context of a wider sample of utilities. However, it may be especially

114. EEI Report, *supra* note 90, at 13.

115. Indeed, the Commission has already approved an index approach in its regulation of oil pipelines. EPACT directed the Commission to "promulgate new regulations to provide a simplified and generally applicable ratemaking methodology for oil pipelines, and to streamline procedures in oil pipeline proceedings." Order No. 561, *Revisions to Oil Pipeline Regulations Pursuant to the Energy Policy Act of 1992*, III F.E.R.C. STATS. & REGS., Regs. Preambles ¶ 30,985, at 30,940 (1993). Although the Commission promulgated this rule to simplify oil pipeline rate regulation, it also recognized that the indexing system is a type of incentive regulation because it "gives greater emphasis to productive efficiency in noncompetitive markets than does traditional cost-of-service regulation." *Id.* at 30,948. It further stated that "[i]ndexing fosters efficiency by severing the linkage under traditional cost-of-service ratemaking between a pipeline's rate changes and changes in its current operating and investment costs. This provides the pipeline with the incentive to cut costs aggressively, since it is assured that it may retain a portion of the savings it generates." *Id.* at 30,948-49 n.37. The baseline established for the majority of the oil pipelines was their then current rates. The index to be used for the annual change in ceiling rates was determined to be the Producer Price Index for Finished Goods, minus one percent. The idea was that rates would increase or decrease, according to the index, thus minimizing the need for future cost-of-service litigation. *Id.* at 30,941. Since indexing went into effect in January 1995, the index has had a negative value in two out of five periods, requiring pipelines to decrease their rates.

116. Johannes P. Pfeifenberger and William B. Tye, *Handle with Care: A Primer on Incentive Regulation*, 23 ENERGY POL'Y 769, 772 (1995).

difficult to develop a comparison group for transmission-only companies because no ITCs are currently in existence. However, if an appropriate comparison group can be found, this model may be preferable because, "in competitive markets, an individual company's performance is directly measured against the performance of other companies."¹¹⁷

Another important aspect of PBR design is the time period between a utility's rate proceedings for which the baseline and the index will be applicable. A recent survey of PBR plans approved by state public utility commissions shows the median time between rate cases increased only from three to five years after the transition from COS to PBR.¹¹⁸ Because the regulatory lag for these plans was only marginally increased, the survey concluded that the plans had not been as effective as they could have been if regulators had extended the time between proceedings for a longer period. The time factor is therefore an important aspect of PBR plans that demands close scrutiny.

Most PBR plans include an external indexing mechanism under which the utility's rates are adjusted upwards to reflect inflation and are adjusted downwards to reflect productivity increases. The Commission has suggested that the applicable inflation index to be used under PBR may either track general prices (such as the Consumer Price Index or the Producer Price Index), or may track utility input prices for a group of utilities in a specific region.¹¹⁹ Most price cap mechanisms utilize the broader economy-wide index instead of the industry-specific index.¹²⁰ Regardless of the type of index chosen, the ITC cannot have the ability to influence the index values. Changes in the company's *specific* costs (those costs over which the utility has control) will not be reflected in the index and will not affect the ITC's rates, but will only have an impact on the ITC's profitability.

The inflation index is generally offset on an annual basis by an appropriate productivity increase. This productivity offset is based on the assumption that a utility's "historical productivity rates can be improved."¹²¹ As with the other components of the PBR mechanism, this offset is calculated at the onset of the plan's implementation and may be determined in various ways. For example, the productivity offset can be measured by either the long-term productivity trend of similar utilities or by the historical productivity trend of the specific utility.¹²² One recent

117. *Id.* at 773.

118. G. Alan Comnes, et al., *Six Useful Observations for Designers of PBR Plans*, ELEC. J., Apr. 1996, at 16 [hereinafter Comnes].

119. In its Policy Statement, the Commission did not express a preference for one form of an index over another. The Commission noted that a general price index is advantageous in that it is simple to use, but that it has little real connection to the utility industry. On the other hand, an industry specific index may have a more direct connection to the specific utility, but it would be much more difficult to apply. Policy Statement, *supra* note 81, at 61,591.

120. Olson & Costello, *supra* note 40, at 34.

121. EEI Report, *supra* note 90, at 18.

122. EEI Report, *supra* note 90, at 18.

survey of PBR plans found that most of the productivity offsets are in the range of 0.2 percent to 1.4 percent per year.¹²³ Intervenors in a PBR proceeding before the Commission may likely seek to include a high productivity offset because larger offsets “are the best way to ensure that customers get a share of the productivity improvements that PBR may bring about.”¹²⁴ The higher the productivity offset, the less impact inflation will have on the utility’s rates.

The EEI Report noted that the inflation and productivity factors often “were integrated together into a single ‘net’ factor.”¹²⁵ For example, if the utility’s PBR mechanism provides for an annual net price increase of two percent, the two percent may be derived from an inflation rate of 2.5 percent and a 0.5 percent productivity offset. Some state commissions have authorized price caps with no price changes, reasoning that any productivity gains are exactly offset by inflation.¹²⁶ Although some utilities have indicated that their productivity factors were based on empirical data, most stated that these figures were simply negotiated with their regulators and “there was no indication that [they were] based on any empirical support or justification.”¹²⁷

Certain costs that are beyond the control of the company are excluded from the PBR computation and are passed through directly to the consumer. These costs, such as increased tax rates, are generally referred to as “Z-factors.” Z-factor costs are not subject to the price cap.¹²⁸ Z-factor costs, which are kept to a minimum to encourage the utility to control its costs as much as possible, include only those items that are beyond the company’s control and that are unique only to a specific company or to the electric industry generally. Any general tax increases or costs associated with broad-based government regulation (i.e., regulations that are not specific to the electric services industry), for example, are already accounted for in an economy-wide price index and are therefore not considered Z-factor costs.¹²⁹ Z-factor costs may also include “costs that are not meant to be subject to cost-cutting pressures, such as demand-side management (DSM) program costs.”¹³⁰

123. Comnes, *supra* note 118, at 18.

124. Comnes, *supra* note 118, at 18.

125. EEI Report, *supra* note 90, at 15. In addition, the profit sharing component of a PBR mechanism may also be rolled into this equation. EEI Report, *supra* note 90, at 15. One commentator has suggested that the inflation index and the productivity offset should be evaluated together “because their combined effect determines the overall aggressiveness of the PBR mechanism.” Comnes, *supra* note 118, at 18.

126. EEI Report, *supra* note 90, at 16.

127. EEI Report, *supra* note 90, at 16.

128. Woolf & Michals, *supra* note 113, at 67.

129. Olson & Costello, *supra* note 40, at 35.

130. BRUCE BIEWALD, ET AL., *Performance-Based Regulation in a Restructured Electric Industry*, PREPARED FOR THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS 10 (1997).

e. The Profit/Loss Sharing Mechanism

Most indexed PBR mechanisms are coupled with a profit-sharing mechanism to ensure that both the utility's ratepayers and its shareholders benefit from the company's increased efficiency. The issue of profit-sharing, however, raises a paradox within the practical application of the PBR model, although a utility may have a greater incentive to develop and implement plans to operate its system efficiently if it is allowed to keep *all* of the savings resulting from its cost-saving measures, such a result would defeat the stated purpose of PBR—to reduce costs to ratepayers. Nevertheless, profit-sharing provisions are designed to ensure that at least some savings resulting from incentive-based ratemaking will be shared between the company's customers and its shareholders, and it appears unlikely that the Commission would approve a PBR plan without the inclusion of some sharing mechanism for the benefit of the ratepayers.¹³¹

Like PBR plans generally, a sharing mechanism can take many forms. The sharing mechanism may be designed as a "neutral zone" or a bandwidth consisting of a range of rates of return, coupled with a sharing arrangement for profits beyond the set boundaries of that bandwidth. Under this approach, the sharing mechanism is activated if the company earns above or below the designated range.¹³² Generally, the bandwidth is defined as between plus or minus fifty to plus or minus 200 basis points around the utility's rate of return.¹³³ For example, if the utility's rate of return is ten percent and its sharing bandwidth is 200 basis points, then the utility will assume all of the profits that accrue with a rate of return between eight percent and twelve percent. The greater the utility's bandwidth, the higher the utility's potential return. However, under a broad bandwidth, the shareholders will bear a greater burden of the downside risks associated with incentive rates. In other words, a broader bandwidth exposes the utility to potentially greater losses. Many PBR plans have stepped sharing mechanisms whereby the shareholders' rate of profits will decline as the utility's level of profitability increases.¹³⁴

Sharing is not always symmetric in terms of profits or losses falling outside of the bandwidth. Some state commissions have refused to allow a utility to share any losses (i.e., any return that comes in below the bandwidth) but only to share excess profits (those that come in above the bandwidth).¹³⁵ In such instances, there is an upper limit on the return that the utility may receive, but no limit on the risk that its return will drop below a certain level. Some state commissions are willing to allow the

131. Policy Statement, *supra* note 81, at 61,592 (stating that "[b]enefit sharing mechanisms are an essential feature of incentive regulation").

132. As discussed below, not every sharing mechanism is activated if the company earns a rate of return *below* the bandwidth. Some sharing mechanisms do not provide that the company's *losses* be shared between ratepayers and shareholders.

133. EEI Report, *supra* note 90, at 21.

134. EEI Report, *supra* note 90, at 21.

135. EEI Report, *supra* note 90, at 21.

utility to accept all of the risks of incentive ratemaking and do not impose any sharing requirement on the PBR mechanism. Other commissions may impose different percentages for the upper and lower bandwidth limits, such as 200 basis points on the upper level of the established return and 100 basis points on the lower level.¹³⁶ These various designs of sharing mechanisms indicate that there is no “correct” way to share the risks between shareholders and ratepayers.

The Commission has expressed a concern that a company not be allowed to game the system by switching between cost-based and incentive-based rates when it is in its economic interest to do so.¹³⁷ Notwithstanding this concern, the Commission may find that a PBR plan may legitimately include a provision reopening the utility’s rate case if the utility’s profits become unreasonably high or low. For example, the PacifiCorp plan (discussed in detail below) provides that “in case of major industry change or corporate structural change, or if the company fails to maintain minimum bond ratings,” then either the company or the Oregon Public Utilities Commission (OPUC) may initiate a reevaluation of the approved alternative ratemaking methodology. The rationale for such a reopener provision is that the downside risks of PBR should not be allowed to interfere with the maintenance of the utility’s financial integrity that is necessary to assure continued service for core customers.¹³⁸ The EEI Report found, for example, that one PBR plan guarantees the utility the ability to receive revenues sufficient to make its debt interest payments. Another PBR proposal would have protected the utility from the downgrading of its bonds.¹³⁹ In other cases, the PBR plan may contain no such provision for reevaluation, and the utility would have to petition its regulators for relief if the actual application of incentive ratemaking threatened to impose on it a “financial catastrophe.”¹⁴⁰ Conversely, the PBR plan may provide for a reopener provision that may be activated if the utility’s profits become unexpectedly or unreasonably *high*.¹⁴¹ Such reopener provisions indicate a concern by regulators that a sharing mechanism should only serve as a “safety net” and the utility should not be able to earn, either unexpectedly high or unexpectedly low, profits.¹⁴²

136. EEI Report, *supra* note 90, at 21.

137. Policy Statement, *supra* note 81, at 61,168-69 (finding that “the utility must be able to keep part of its productivity gains or suffer part of the losses over the long-term.”).

138. EEI Report, *supra* note 90, at 21.

139. EEI Report, *supra* note 90, at 21.

140. EEI Report, *supra* note 90, at 21.

141. Regulators may be disinclined to allow a utility the potential for an unlimited return. The EEI Report indicated that some “commissions were ‘embarrassed’ that so much profit had been made from the PBR.” EEI Report, *supra* note 90, at 21. Similarly, one utility noted that its PBR plan had been so successful that its state commission had required it to increase its productivity factor in order to afford its customers additional benefits from the plan. EEI Report, *supra* note 90, at 23.

142. Olson & Costello, *supra* note 40, at 36.

f. The Quality Control Mechanism

Most, if not all, PBR proposals approved by state regulators include a quality control mechanism to "insure that the utility does not pursue cost savings at the expense of system reliability, safety, customer satisfaction, or other measures of quality."¹⁴³ In its Policy Statement, the Commission required each proposal for incentive regulation "specifically demonstrate how quality of service is measured, and how it will be maintained or enhanced."¹⁴⁴ Such a mechanism alleviates any concern that a utility may attempt to increase its profits by cutting quality standards.¹⁴⁵ In addition, PBR increases the "regulatory lag" between rate cases. Because the Commission often uses a rate case as an opportunity to assess the utility's service quality (in reviewing the utility's O&M expenses, for example), the Commission may demand assurance from a utility that requisite quality control mechanisms have been put into place for the extended period between formal rate proceedings.

The quality control component of most state-approved PBR plans ensures the utility will not increase its profits by decreasing customer service, service reliability, or customer satisfaction.¹⁴⁶ The main concern when applying PBR to an ITC will be in ensuring the ITC does not pursue any cost savings at the expense of the system's reliability. These reliability concerns, as addressed above, should not pose a problem for regulators of ITCs. For example, an ITC has, by virtue of its for-profit status, an incentive to ensure the reliable operation of its grid to maximize its sales and thereby maximize its profits. Moreover, the ITC will have to comply with the Commission's ISO principles which will require the ITC to ensure the short-term reliability of the grid operations.¹⁴⁷ The ISO principles will require an ITC to follow the reliability protocols established by the regional reliability organizations.

g. A Specific PBR Example

The Commission has never considered a PBR plan for a transmission-only utility. Although there are distinctions between an incentive-based rate plan applied by a state regulator to a utility's distribution function and

143. Peter Navarro, *The Simple Analytics of Performance-Based Ratemaking: A Guide for the PBR Regulator*, 13 YALE J. ON REG. 113 (1996).

144. Policy Statement, *supra* note 81, at 61,590. This quality assurance requirement was confirmed in the Commission's January 31, 1996 Statement of Policy. 74 F.E.R.C. at 61,237.

145. As Ms. Alexander states:

Once a utility is allowed to make more money by selling competitive services under flexible pricing schemes, it is only natural for corporate management to want to reduce operations and maintenance budgets in areas that are still monopolistic under the drive for efficiency, and divert the resulting savings into more lucrative unregulated markets.

Barbara R. Alexander, *How to Construct a Service Quality Index in Performance-Based Ratemaking*, ELEC. J., Apr. 1996, at 47.

146. *Id.*

147. Order No. 888, *supra* note 1, at 31,731.

an incentive-based rate plan applied to an ITC by the FERC, state-sanctioned PBR models may offer some guidance as to how an ITC's PBR mechanism should be structured. In addition, state PBR plans may indicate those aspects of a proposal that the Commission may believe warrant special attention. The following is a discussion of one plan which the Oregon Public Utilities Commission (OPUC) recently adopted for Pacific Power and Light Company's (PacifiCorp) distribution function.¹⁴⁸

Pursuant to a provision in the Oregon statutes, the OPUC may approve an "alternative form of regulation" or AFOR if the utility's proposal,

(A) Promotes increased efficiencies and cost control; (B) is consistent with least-cost resources acquisition policies; (C) is consistent with maintenance of safe, adequate, and reliable service; and (D) is generally beneficial to utility customers, for example, by minimizing rates.¹⁴⁹

The PacifiCorp plan appears to be fairly representative of many of the PBR mechanisms which have been approved by state regulators, and may provide some guidance as to the Commission's treatment of an incentive-based rate proposal.

The OPUC approved the PacifiCorp distribution-only incentive plan for a period to run through June 30, 2001. In the plan's final year, PacifiCorp will make a recommendation to the OPUC as to whether the plan should be continued. If PacifiCorp recommends such continuation and the OPUC approves the recommendation, the plan will continue unchanged for an additional three years.¹⁵⁰ The plan also contains a re-evaluation provision under which either PacifiCorp or the OPUC "may, at any time, initiate a re-evaluation of all aspects of the distribution-only AFOR in case of major industry change or corporate structural change, or if the company fails to maintain minimum bond ratings."¹⁵¹ This provision is intended to protect the financial integrity of PacifiCorp throughout the term of the plan. In addition, the OPUC may terminate the plan at any time if the company is not abiding by its provisions, including the provisions related to service quality measurement.¹⁵²

148. Public Utility Commission of Oregon, Order No. 98-191, (May 5, 1998) <<http://www.puc.state.or.us/orders/98orders>> [hereinafter Order No. 98-191]. The copy of the order cited herein is taken from the OPUC web site. Note that all citations to Order No. 98-191 refer to the page numbers of that downloaded document.

149. AFOR refers to "a plan adopted by the commission upon petition by a public utility, after notice and an opportunity for a hearing, that sets rates and revenues and a method for changes in rates and revenues using alternatives to cost-of-service rate regulation." OR. REV. STAT. § 757.210(2)(c) (1997).

150. Order No. 98-191, *supra* note 148, at 10 app. A.

151. Order No. 98-191, *supra* note 148, at 10 app. A. The plan also provides that if the company's bond rating for senior debt with Moody's and S&P falls below Baa2 and BBB, respectively, either PacifiCorp or the OPUC may request a reevaluation of the plan. Order No. 98-191, *supra* note 148, at 16.

152. Order No. 98-191, *supra* note 148, at 11 app. A.

The PacifiCorp plan is based on an index-related price adjustment under which the maximum percentage price change is determined by the forecast change in DRI/McGraw Hill GDP price index minus an annual productivity offset of 0.3 percent.¹⁵³ The plan limits the overall price increase to two percent for any one year (starting each year on July 1), and to five percent over the term of the plan.¹⁵⁴ PacifiCorp may request less than the allowed price increase (in which case the company may carry the foregone increase forward and apply it later) and may request a price decrease at any time. PacifiCorp is required to apply any index-based price decrease, except when earnings are within the sharing zones, as described below.¹⁵⁵

Any "major events" outside of PacifiCorp's control will be reflected in the annual price change and should have no impact on the company's projected earnings.¹⁵⁶ Such major events are limited to changes in federal, state, and local taxes, including energy-related tax. PacifiCorp may pass through all taxes (except any energy-related tax) to its customers after an annual threshold of one percent of its Oregon retail revenues. As for any energy-related tax, PacifiCorp will be allowed to demonstrate to the OPUC in a separate proceeding that it should recover such costs outside of any index-related change.¹⁵⁷

The plan includes an annual earnings review and potential rate adjustment based on PacifiCorp's overall company earnings in Oregon for the prior calendar year. If PacifiCorp's earnings for that year are within 250 basis points of its return on equity (ROE) benchmark, then there will be no adjustment to the earnings band. If the variance is between 251 and 350 basis points above or below the benchmark, then the resulting price increase or price decrease will equal one fourth of the adjustment needed to reach 250 basis points. If the variance is 350 basis points above or below the benchmark, then the resulting price increase or price decrease will equal the sum of one half of the price increase or decrease needed to reach 350 basis points plus one fourth of the additional price decrease or increase required to reach 250 basis points. PacifiCorp's initial ROE benchmark will be ten percent and will be adjusted annually depending on the change in interest rates and the change in electric utility industry yields. The company's capital structure is to remain constant throughout the term of

153. Order No. 98-191, *supra* note 148, at 11 app. A. Any price increase will therefore always be less than inflation.

154. Order No. 98-191, *supra* note 148, at 11 app. A.

155. In addition to the index-related price adjustment mechanism as described above in the text, the plan includes a revenue cap mechanism by which,

temperature adjusted actual sales revenues of each major customer class will be compared to a predetermined revenue cap for that class, and any differences will be collected in a balancing account for recovery the following year. This mechanism ensures that PacifiCorp's ability to recover distribution system costs will be independent of retail kilowatt-hour use.

Order No. 98-191, *supra* note 148, at 6.

156. Order No. 98-191, *supra* note 148, at 14 app. A.

157. Order No. 98-191, *supra* note 148, at 14 app. A.

the plan.¹⁵⁸

The plan implements eight comprehensive performance measures for evaluating service quality in order “to ensure [that] service quality is maintained at current or improved levels subsequent to the implementation.”¹⁵⁹ These measures will be in effect for ten years (beginning January 1998) and are thereby independent of the continued existence of the plan. The plan also mandates revenue requirement deductions for poor performance under the standards.

Thus, although the Commission has never considered an incentive-based rate plan for a transmission-only company, PBR is a critical tool that the Commission may utilize to encourage ITC formation. While PacifiCorp’s plan appears to be fairly representative of many of the PBR mechanisms which have been approved by state regulators, its applicability as part of an ITC proposal to be presented to the Commission is open to speculation. However, the PacifiCorp plan does provide a specific example of how the components of an incentive-based rate mechanism should work together, and provides some guidance as to how a utility may wish to structure a PBR plan in its proposal to form an ITC.¹⁶⁰ As discussed above, the utility should carefully tailor any PBR proposal to meet its specific needs.

B. The Great ISO/ITC Debate

1. The Incentive To Construct New Transmission Facilities and Maximize the Usage of the System

Both ISOs and ITCs will be charged with maintaining system reliability and alleviating transmission constraints on a long-term and short-term basis. In the short-term, the Commission’s *pro forma* tariff, which would be applicable to both ISOs and ITCs, provides the rules for determining available capacity (including redispatch obligations),

158. Order No. 98-191, *supra* note 148, at 13.

159. Order No. 98-191, *supra* note 148, at 15 app. A.

160. While the Commission has never considered incentive ratemaking for a transmission-only utility, the National Grid Company (NGC) in the United Kingdom, privatized a bulk transmission network as part of the restructuring of that country’s electric utility industry in 1990. The network operates under a system of performance-based regulation. Prices are determined by the “RPI minus X” formula, under which the “RPI” is the retail price index and “X” is the efficiency factor determined by Britain’s Director General for Electricity Supply and the Office for Electricity Regulation. Charles M. Studness, *Price-Cap Regulation: Will It Survive in the U.K.?*, PUBLIC UTIL. FORT., June 15, 1995. If the NGC can improve its productivity by more than X, it will keep the excess earnings until the next price review. While productivity has increased under the “RPI minus X” formula, there have been some complaints that not enough benefits have been passed through to the customers. *Id.* While the NGC model may be the only instance of incentive ratemaking applied to a transmission-only utility, its applicability to the U.S. electric utility industry, which has had a markedly different history than that in Britain, should be carefully reviewed. See generally Larry E. Ruff, *Electricity Restructuring in Two Nations: Different Paths to a Competitive Future*, PUBLIC UTIL. FORT., June 22, 1989.

alleviating constraints and maintaining reliability.¹⁶¹ On a long-term basis, however, ITCs and ISOs will have different roles in alleviating transmission constraints and maintaining reliability.

For some, adding new transmission facilities or upgrading existing facilities may be the most difficult solution to reliability problems or transmission constraints.¹⁶² For others, a generation solution, such as construction of new generation capacity or employment of must-run units, or load-based solutions, such as demand-side management or use of interruptible service, may be more appropriate. Decisions regarding the most efficient manner of relieving system constraints and maintaining reliability in the long-term, including the need for new facilities or upgrades, are critical issues that are affected by the different incentives facing ISOs and ITCs. Some commentators have argued that an ITC, which owns and operates the transmission system (and is not affiliated with any generation), will have no incentive to consider generation or load-based solutions to maintain reliability or to alleviate constraints.¹⁶³ Because an ITC can maximize its profit by enlarging its rate base, some commentators argue that a transmission-only company may bias its reliability/constraint decisions towards favoring a transmission solution over a more efficient generation or load-based solution. By contrast, an ISO, which has no affiliation with transmission owners or generation owners, would have no bias toward any particular solution.

An ISO must rely on the transmission owners to make any necessary investment in new transmission facilities. The ISO's role in planning is limited to that "of coordinating and providing information and expertise, not really driving the process or making the final decisions on facilities."¹⁶⁴ Because the transmission owners may not benefit from such investment, they may be reluctant to undertake any construction that is deemed necessary by the ISO.¹⁶⁵ An ITC, on the other hand, as the transmission

161. Order No. 888-A, *supra* note 1, at 30,520.

162. For short-term constraints or reliability problems, the ISO or ITC will have a duty to redispatch the system consistent with the *pro forma* tariff to alleviate the constraint or reliability problem. Order 888-A, *supra* note 1, at 30,516, 30,536.

163. Fiona Woolf, Comments Before the Washington, D.C. ISO Conf. (Apr. 16, 1998), in F.E.R.C. Docket No. PL 98-5-000, at 10.

164. David LaPlante, Comments on Behalf of NEPOOL Before the Washington, D.C. ISO Conf. (Apr. 16, 1998), in F.E.R.C. Docket No. PL98-No. 5-000, at 14.

165. At the New Orleans ISO conference, Frank Gallagher, President and Chief Utility Operating Officer for Entergy, stated that Entergy's proposal calls for an annual regional planning summit during which all of the market participants would be able to let Entergy know what facility additions or updates they thought should be made. The ITC would then develop an expansion plan that would include the input from the various parties. Mr. Gallagher noted that because the ITC would both own and operate the transmission facilities, it would be in a better position to follow-through on the proposed expansion plan than would an ISO. In the case of an ISO, it is not clear that the transmission owner will in all instances agree to the construction of facilities that the ISO has found to be necessary for the reliability of the grid. Frank Gallagher, Comments on Behalf of Entergy Services, Inc. Before the New Orleans, L.A. ISO Conf. (June 1, 1998), in F.E.R.C. Docket No. PL98-5-000, at 48-49. It is unclear to what extent Entergy, under its proposal, would be required to actually take into account the suggestions made by the market participants at the "summit" when implementing its expansion plan.

owner, would not have to obtain another entity's approval (other than state and local siting authorities) before undertaking new construction. Its decision will be based on a careful cost/benefit analysis. In this same vein, the transmission owners of ISO-controlled facilities may not view system maintenance as a high priority, as they will likely seek more profitable uses for their limited capital. Conversely, ITCs would give system maintenance a high priority because effective maintenance is required to ensure reliability and to maximize usage of their systems.

Because an ITC may be able to increase its profits by constructing new facilities (i.e., by increasing the capacity of its system and increasing its rate base), it follows that the transmission-owning entity may prefer to resolve a transmission constraint with an investment in new transmission facilities. However, there is a distinct difference between the ITC's bias in favor of a transmission solution and the ITC's ability to undertake a transmission solution over a generation or load-based solution. In some instances, siting or environmental concerns may dictate that new transmission system cannot be built, leaving only a generation or load-based solution. Moreover, the ITC would have to make a showing to local authorities any proposed new construction is necessary.

An ITC's tendency to favor a transmission solution may have additional limitations. Order No. 888's *pro forma* tariff requires utilities to provide transmission to "any entity that can request transmission services under section 211" which includes "any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale."¹⁶⁶ Because of this requirement, the ITC may not have the opportunity to favor a transmission solution. In a properly functioning competitive market, a potential generation investor will have economic incentives to construct new generation within transmission constrained regions. The generator can then require the ITC to interconnect to the new facilities and provide transmission service under the ITC's open-access tariff. The generator's investment incentives are provided by the generator's opportunity to avoid congestion-related transmission charges and thus capture some of this economic gain in market prices for its energy. Those incentives exist if the ITC has properly implemented its congestion management and pricing rules. The opportunity to capitalize on these incentives will be guaranteed if the ITC's interconnection rules and charges are minimally burdensome and fairly priced.¹⁶⁷ If, given that these fair and nondiscriminatory rules are in place, there are still insufficient economic incentives for new generation investment, a transmission solution is likely the lowest cost solution.

Thus, ITCs may prove to be more efficient than ISOs with respect to maintaining long-term reliability and alleviating constraints. Unlike ISOs, ITCs would be profit-motivated and thus would have the incentive to

166. Order No. 888, *supra* note 1, at 31,687.

167. This situation dictates that an ITC's congestion management and pricing, as well as its assurance of fair interconnection access and pricing, will be carefully scrutinized by the Commission.

increase overall use of the transmission system, whether through upgrades, new facilities or operating efficiencies. Increasing the overall use of the system would not only benefit the ITC's bottom line, but would also facilitate competition by creating opportunities to reach new buyers and sellers.

The existence of an ITC should similarly prove no bar to the use of economically efficient load-based solutions to transmission constraints. The logical place to pursue load-based solutions is through the entity serving the load. When that entity is a franchised public utility with the exclusive service right, the regulator will require the utility to pursue the lowest cost method to serve its customers. In general, regulators have expressed significant interest in the use of load-based programs such as demand side management and interruptible service. With the introduction of retail competition, retail service providers can also be expected to pursue demand side management and interruptible service if such approaches provide them an effective way to control transmission costs and deliver a competitively priced service.

2. Pancaked Pricing And The Question Of Critical Mass

Although public utilities have historically constructed generation facilities near their customers, various technological advancements now allow for electricity to be transmitted economically over longer distances.¹⁶⁸ Allowing purchasers to consider power supply options from sources outside of their immediate geographic area further promotes the development of large power markets and allows the purchaser to seek out the lowest cost supplies. Prior to the issuance of Order No. 888, such long distance purchases were inhibited by: (1) the lack of transmission access; and (2) the existence of pancaked rates.¹⁶⁹ Order No. 888 only addressed the question of access to transmission services. In fact, the Commission has been criticized for Order No. 888's failure to "address the single most important impediment to wholesale competition—the existing practice of allowing 'pancaked' transmission charges by each transmission owner along a 'contract path' between generator and customer."¹⁷⁰ Because of the continued impact of rate pancaking, "power purchasers can realistically only consider economic purchases in close geographic proximity," even under the current open-access environment.¹⁷¹

168. "In the late 1960s and 1970s, improved transmission efficiency and development of regional transmission networks 'made it possible to build power plants up to 1000 miles from power users.'" Order No. 888, *supra* note 1, at 31,036, n.31 (quoting Bernard S. Black & Richard J. Pierce, Jr., *The Choice Between Markets and Central Planning in Regulating the U.S. Electric Industry*, 93 COLUM. L. REV. 1339, 1345 (1993)).

169. Pancaked rates refer to the stacking of various utilities' rates as electricity is transmitted longer distances over a contract path. The more systems over which electricity is transmitted, the higher the price for transmission.

170. John C. Berlier, Jr. & David J. McCarthy, *A Proposal To Rationalize Transmission: Picture the Grid as a Lake . . .*, ELEC. J., June 1996, at 14.

171. *Id.*

In addition to the benefit that larger transmission providers have in eliminating pancaked rates, various commenters have suggested that larger providers can also manage grid reliability more efficiently and have more resources with which to meet various contingencies.¹⁷² In addition, the larger the control area, the more effectively the regional transmission provider will be in internalizing loop flows.¹⁷³ Some commenters have even gone so far as to suggest that “an ISO should be no smaller than an existing NERC reliability region, and in most cases should be larger.”¹⁷⁴

Regional transmission providers are viewed as a means of eliminating the market barriers created by rate pancaking.¹⁷⁵ Unlike the Commission’s functional unbundling requirements which do not require the elimination of pancaked rates, Order No. 888’s third ISO principle requires that any ISO should provide open-access to the transmission system and all services under its control at *non-pancaked rates* pursuant to a single, unbundled, grid-wide tariff applying to all eligible users in a non-discriminatory manner.¹⁷⁶

Because this ISO principle also requires that an “ISO should be as large as possible” and all transmission services within the ISO should be taken pursuant to a single systemwide tariff,¹⁷⁷ an ISO necessarily diminishes the impact of pancaked rates and increases the market area within which a purchaser can seek a supplier.

An ITC, which would provide a gridwide tariff under which transmission services would be offered on a systemwide basis, can also promote the regionalization of the grid and the elimination of pancaking, just as an ISO. The difference between an ISO and ITC in this respect, however, is a question of size. Because an ITC will be established through the divestiture of assets from a vertically-integrated utility, the area covered by its transmission grid will generally be smaller than that of an ISO formed by the transmission facilities of numerous entities.¹⁷⁸ Even

172. David W. Joos, Comments on behalf of Consumers Energy Co. Before the Indianapolis, Ind. ISO Conf. (June 4, 1998), in F.E.R.C. Docket No. PL98-5-000, at 146-147.

173. *Id.* A loop flow is a “phenomenon resulting from the fact that electricity will flow from one point to another on all transmission paths connecting those points rather than any single such path. Loop Flow is the flow that takes place on all paths other than the path designated by the contract or otherwise.” AMERICAN BAR ASSOCIATION: SECTION OF PUBLIC UTILITY LAW, A GLOSSARY OF TERMS ENCOUNTERED IN ELECTRIC UTILITY, NATURAL GAS, AND TELECOMMUNICATIONS REGULATION AND LITIGATION.

174. John Procario, Comments on Behalf of Cinergy Services Inc. Before the Washington, D.C. ISO Conf. (Apr. 15, 1998), in F.E.R.C. Docket No. PL98-5-000, at 10. However, other commenters have noted that a large regional transmission provider “may well result in a lack of attention to local transmission issues.” NSP Comments, *supra* note 41, at 4.

175. The Commission has stated that a “regional, multilateral ISO will serve to eliminate pancaked transmission rates and should encourage competition in bulk power supply on a broader, geographic scale.” *Wisconsin Elec. Power Co.*, 79 F.E.R.C. ¶ 61,158, at 61,702 (1997).

176. Order No. 888, *supra* note 1, at 31,731 (emphasis added).

177. Order No. 888, *supra* note 1, at 31,731.

178. “However, there may be instances (such as the transmission facilities that are owned by the Entergy companies) in which the transmission facilities of a single utility are sufficiently large that they

though the ITC proposals currently being discussed contemplate more than one utility divesting their assets to form a single ITC,¹⁷⁹ it is still possible an ITC will not initially be able reach the critical mass necessary to regionalize the grid and eliminate pancaking as effectively as an ISO.

However, it should be noted that public utilities have thus far been less than enthusiastic about joining ISOs. In fact, ISOs are currently only operating in those areas where there is a pre-existing tight power pool or a state mandate. The history of the Desert STAR and INDEGO negotiations demonstrates the difficulties involved when a number of utilities are involved in discussions regarding the relinquishment of operational control over their transmission facilities to an independent grid operator in the absence of a federal or state mandate.¹⁸⁰ The choice may therefore not be between a large ISO and numerous smaller transmission entities, but rather between ITCs and no independent regional transmission providers at all. Any discussion on the future of such transmission providers must realistically consider whether it is preferable to regionalize the grid through ITC formation, rather than to wait for voluntary ISO formation, which may be delayed significantly.¹⁸¹

3. ISOs May Provide A Better Alternative for Development of an Independent Transmission Provider in Certain Circumstances

To date, the Commission has waited for market participants to voluntarily submit ISO proposals. It has then reviewed such proposals, based on written pleadings and informal technical conferences within the context of Order No. 888's eleven ISO principles.¹⁸² Although the Commission has provided substantial guidance on ISO formation in Order No. 888 and in subsequent orders,¹⁸³ there has been little ISO activity

can be considered to constitute a region and could be operated efficiently as an ITC." NSP Comments, *supra* note 41, at 3.

179. NSP noted in the Kansas City ISO conference that "we don't think that NSP in the upper Midwest is a reasonably large transmission owner. We don't think that we're large enough in the long run to effectively provide the open access to a wide region that [the Commission suggests]. We think we will need other market participants, other transmission assets to come in" Anthony G. Shuster, Comments Before the Kansas City, Mo. ISO Conf. (May 29, 1998), in F.E.R.C. Docket No. PL98-5-002, at 111.

180. Comments Before the Phoenix, Ariz. ISO Conf. (May 28, 1998), in F.E.R.C. Docket No. PL98-5-000. See also Comments Before the Portland, Or. ISO Conf. (June 5, 1998), in F.E.R.C. Docket No. PL98-5-000.

181. Moreover, many commenters believe that that ITCs will quickly merge into larger entities. Anthony G. Shuster, Comments on Behalf of Northern States Power Before the Kansas City, Mo. ISO Conf. (May 29, 1998), in F.E.R.C. Docket No. PL98-5-002, at 112. "Our expectation is that grid integration will come and it will come rapidly. Many of those transmission owners have no particular interest in the [transmission] business other than the essential nature in order to historically provide their generation to load connection."

182. At this writing, the Commission has not set an ISO tariff or tariff changes for formal hearing. *Pacific Gas & Elec. Co.*, 81 F.E.R.C. ¶ 61,122, at 61,444-46 (1997); *PECO Energy Co.*, 81 F.E.R.C. ¶ 61,257, at 62,237-38 (1997).

183. See, e.g., *Pacific Gas & Elec. Co.*, 81 F.E.R.C. ¶ 61,122 (1997); *Pennsylvania-New Jersey-Maryland*, 81 F.E.R.C. ¶ 61,257 (1997); *New England Power Pool*, 79 F.E.R.C. ¶ 61,374 (1997) *reh'g*

outside of tight power pools, state-mandated ISOs, and in those areas where there is significant merger activity.¹⁸⁴

a. Where There Is an Existing Tight Power Pool

In Order No. 888, the Commission required members of “tight” power pools¹⁸⁵ to file joint poolwide *pro forma* tariffs no later than December 31, 1996 and begin to take service under their open-access tariffs by that date.¹⁸⁶ Order No. 888 required that such pools “establish open, non-discriminatory membership provisions (*including establishment of an ISO, if that is a pool’s preferred method of remedying undue discrimination*) and modify any provisions unduly discriminatory or preferential.”¹⁸⁷ The decision as to whether the tight power pool should establish an ISO was left to the pool itself. The Commission subsequently held if a tight power pool chooses to establish an ISO, it will be bound by the eleven ISO principles formulated in Order No. 888.¹⁸⁸

Three of the four tight power pools identified by the FERC—PJM, the New York Power Pool and NEPOOL—have filed ISO proposals and have received at least conditional approval to operate as such. The oldest and largest of these tight pools is the Pennsylvania-New Jersey-Maryland (PJM) pool, first established in 1927.¹⁸⁹ PJM’s current service area covers five states in the mid-Atlantic region, along with the District of Columbia, making it the largest centrally-dispatched control area in the United States.¹⁹⁰ The PJM ISO is responsible for centralized scheduling and dispatch of generation, for operating a bid-based energy trading market, for monitoring and coordinating the operation of the transmission system and for administering the PJM Open-Access Tariff.¹⁹¹

pending.

184. Even in those areas with significant merger activity, utilities have shown a reluctance to participate in ISO. Compare *Ohio Edison Co.*, 81 F.E.R.C. ¶ 61,401, at 61,408 (1997) (stating that the merging parties’ “participation in an ISO will help address the uncertainty surrounding how FirstEnergy will ensure an open and competitive market in its service area”), with Tony Alexander, Comments on Behalf of First Energy Corp. Before the Indianapolis, Ind. ISO Conf. (June 4, 1998), in F.E.R.C. Docket No. PL98-5-004, at 65. (stating that “ISOs serve a purpose, but mandatory participation in any type of transmission entity at this [time] could foreclose or limit other options”).

185. The Commission listed the tight power pools as: New York Power Pool, New England Power Pool, Pennsylvania-New Jersey-Maryland Interconnection, and the Michigan Electric Coordinated Systems. Order No. 888, *supra* note 1, at 31,727.

186. The Commission subsequently issued an order extending the date by which power pools must take service under their pool-wide open-access tariffs by 60 days. *Promoting Wholesale Competition Through Open-Access Non-discriminatory Transmission Services by Public Utilities, Notice of Extension of Time and Clarifying Service and Docketing Procedures*, 76 F.E.R.C. ¶ 61,347, at 62,647 (1996).

187. Order No. 888, *supra* note 1, at 31,727 (emphasis added).

188. *Atlantic City Elec. Co.*, 77 F.E.R.C. ¶ 61,148, 61,573 (PJM Guidance Order).

189. PJM Interconnections, L.L.C., *Who We Are—What We Do* (visited Oct. 1, 1998) <<http://www.pjm.com/about/general>>, at 1. Note that all citations to this cite refer to the page numbers of that downloaded document.

190. *Id.* at 1-2.

191. *Id.* See also *Pennsylvania-New Jersey-Maryland Interconnection*, 81 F.E.R.C. ¶ 61,257 (1997),

Like PJM, NEPOOL has a fairly long history of interconnected operations, and has opted to convert to an ISO as part of its overall restructuring. NEPOOL was first formed in 1971 as a voluntary association of utilities in the Northeastern states, which sought to maximize the economic benefits of interconnected operations through centralized dispatch.¹⁹² On June 25, 1997, the Commission issued an order conditionally authorizing NEPOOL's establishment of the New England ISO and the transfer of jurisdictional facilities to an ISO on an interim basis.¹⁹³ As discussed in the Commission's recent ruling on NEPOOL's comprehensive restructuring proposal, the ISO will not only be responsible for administering the NEPOOL open-access tariff and ensuring transmission system reliability, but will also administer a regional power exchange.¹⁹⁴

Finally, the Commission recently approved the New York Power Pool's (NYPP) ISO proposal, subject to certain conditions.¹⁹⁵ NYPP was originally formed by the seven investor-owned utilities in New York in 1966, with the New York Power Authority joining in 1967.¹⁹⁶ In addition to meeting the requirements of Order No. 888, NYPP's proposal was designed to accommodate the New York State Commission's requirements for implementation of retail access.¹⁹⁷ Under the terms of the NYPP proposal, the pool will dissolve and transfer its functions to the new ISO, with a separate power exchange to be developed in the future.¹⁹⁸

While these pool members' experience in giving up partial control of their systems probably accounts for their greater willingness to consider an ISO structure, the existence of centralized administrative structures also allowed them to convert to an ISO at a relatively low cost.¹⁹⁹ In these limited circumstances, where there is a long history of centrally-controlled regional operations, ISOs appear to offer an immediate and feasible means of ensuring nondiscriminatory transmission access.

b. Where There Is a State-Mandated ISO

The Electric Reliability Council of Texas (ERCOT) is one of the ten Regional Reliability Councils of NERC, an organization that promotes the reliability of the nation's electricity supply. Because ERCOT represents

clarified, 82 F.E.R.C. ¶ 61,068 (1998) *reh'g pending*.

192. ISO New England Inc., *New England Power Pool* (visited Oct. 1, 1998) <http://www.iso-ne.com/about_the_iso/NEPP.html>.

193. *New England Power Pool*, 79 F.E.R.C. ¶ 61,374 (1997).

194. *New England Power Pool*, 83 F.E.R.C. ¶ 61,045 (1998).

195. *Central Hudson Gas & Elec. Corp.*, 83 F.E.R.C. ¶ 61,352 (1998).

196. New York Power Pool, *New York Power Pool* (visited Oct. 1, 1998) <<http://www.nypowerpool.com/who.shtml>>.

197. *Central Hudson Gas & Elec. Corp.*, 83 F.E.R.C. ¶ 61,352 (1998).

198. *Id.*

199. Ricky Bittles, Comments on Behalf of Arkansas Electric Coop. Corp. Before the New Orleans, L.A. ISO Conf. (June 1, 1998), in F.E.R.C. Docket No. PL98-5-000, at 59.

an electric system totally within the State of Texas,²⁰⁰ it is not FERC-jurisdictional but is primarily under the jurisdiction of the Public Utility Commission of Texas (PUCT). As a NERC Regional Reliability Council, ERCOT's responsibility traditionally has been to ensure the reliability of the bulk electric system within Texas. In 1995, the Texas legislature revised the Public Utility Regulatory Act to deregulate the state's wholesale generation market.²⁰¹ In early 1996, the PUCT issued rules to implement these amendments, including a requirement of a joint industry filing regarding the creation of a state wide ISO.²⁰² The PUCT required that the filing provide for an ERCOT ISO to oversee security operations, the efficient use of the transmission system by all market participants, and the coordination of transmission planning.²⁰³ In August 1996, the PUCT endorsed the joint industry filing which created an ISO under a restructured ERCOT organization. The ERCOT ISO began operations on September 11, 1996, as the nation's first ISO. As an ISO, ERCOT's functions are no longer limited to ensuring the reliability of Texas' bulk transmission system, but now include the facilitation of the state wholesale market generally.

The formation of the California ISO was different from the ERCOT ISO in that, in California, the actions of the state regulatory body preceded any legislative action. In California, the Public Utilities Commission of the State of California (CPUC) instituted an investigation that resulted in a rulemaking ordering the creation of an ISO and a power exchange to facilitate retail competition in California.²⁰⁴ Subsequently, the state legislature amended the California Public Utilities Code to do the same, directing that the ISO begin operations on January 1, 1998.²⁰⁵ After a three month delay, the California ISO began operations on March 31, 1998, and now operates the transmission grid in California.

The experiences in California and Texas demonstrate that, where a state legislature mandates ISO formation, there may be little incentive to establish separate, for-profit transmission companies. Instead, utilities have already handed over control of their transmission systems to an ISO may be disinclined to explore the potential benefits of ITC formation.²⁰⁶

200. The system represented by ERCOT serves approximately eighty-five percent of the state's electrical load. ERCOT INDEPENDENT SYSTEM OPERATOR, THE ERCOT ISO RELIABILITY AND MARKET FACILITATION 2 (Feb. 1997) [hereinafter ERCOT].

201. Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 11.001-.009. (West 1998).

202. Public Utility Commission of Texas' Substantive Rule 23.67(p), *codified at* 16 TEX. ADMIN. CODE § 23.67(p) (West 1998).

203. ERCOT, *supra* note 200, at 3.

204. *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation; Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation*, Decision No. 95-12-063, 1996 Cal. PUC LEXIS 28, 166 P.U.R. 4th 1 (Jan. 10, 1996).

205. A.B. 1890, Reg. Sess. (Cal. 1995-96), 1996 Cal. Legis. Serv. ch. 854 (West) (signed into law by Governor Pete Wilson on Sept. 23, 1996).

206. *But see* WIS. STAT. § 30.196.485(i)(2) (1996). This Wisconsin statute requires utilities to have

c. Where There Is Significant Merger Activity

i. The Commission's Section 203 Conditioning Authority to Encourage ISOs

Under section 203(a) of the FPA, the Commission has the authority to consider the merger applications of public utilities and "shall approve" a proposed merger of certain facilities "[a]fter notice and opportunity for hearing, if the Commission finds that the proposed disposition, consolidation, acquisition, or control will be consistent with the public interest."²⁰⁷ The Commission has concluded, because section 203(a) grants it the authority to deny a merger, it necessarily also has the implied authority to place conditions upon its approval of a transaction not otherwise meeting the public interest standard.²⁰⁸

In its Merger Policy Statement, the Commission noted an ISO may be an effective mechanism for mitigating market power in a section 203 merger proceeding because "an ISO might facilitate the implementation of efficient transmission pricing and thereby expand the effective scope of the geographic market."²⁰⁹ Indeed, in recent merger cases the Commission has either strongly encouraged ISO participation or recognized that an ISO may resolve certain types of market power concerns. In *Ohio Edison Company*, for example, the Commission conditionally approved the merger of Ohio Edison Company, Pennsylvania Power Company, Cleveland Electric Illuminating Company, and Toledo Edison Company to form First Energy Corp. (First Energy) despite concerns the proposed merger would have a negative impact on transmission access to the First Energy system.²¹⁰ The Commission found "[b]ecause the facts of this case are not completely clear, we are left with some concerns that Applicants could plan and operate their transmission system in such a way as to potentially exercise the substantial generation market power indicated by the relatively high levels of merger-induced market concentration."²¹¹ The Commission concluded that the merger applicants' "participation in an ISO will help address the uncertainty surrounding how First Energy will ensure an open and competitive market in its service area," and stated "we expect First Energy to participate in the Midwest ISO or another

transferred control over their transmission facilities to an ISO by June 30, 2000, or to have divested, with the Commission's approval, their interest in transmission facilities by that date.

207. 16 U.S.C. § 824b(a) (1994).

208. 45 F.E.R.C. at 61,280. In addition, the Commission has the explicit authority under section 203b to place conditions on a merger application "to secure the maintenance of adequate service and the coordination in the public interest of facilities subject to the jurisdiction of the Commission." 16 U.S.C. § 824b(b) (1994). This conditioning authority extends to "such orders supplemental to any order made under this section as it may find necessary or appropriate." *Id.*

209. Merger Policy Statement, *supra* note 78, at 30,120.

210. 81 F.E.R.C. ¶ 61,110 (1997).

211. *Id.*

appropriate ISO.”²¹² The Commission concluded that if the applicants failed to participate in an acceptable ISO process, it would “not hesitate to impose additional conditions under its section 203(b) [conditioning] authority.”²¹³

Similarly, the Commission approved a merger between Louisville Gas and Electric Company (LG&E), LG&E Electric Marketing, Inc., and Kentucky Utilities (KU), despite finding the proposed merger raised some potential competitive concerns with respect to the full requirement customers of KU.²¹⁴ The Commission noted as part of the applicants’ plan to mitigate any negative effect on competition, KU and LG&E had been actively participating in the Midwest ISO filings. The Commission stated if the parties at some point seek to withdraw from the ISO, the Commission “will evaluate that request in light of its impact on competition in the KU destination markets, use our authority under section 203(b) of the FPA to address any concerns, and order further procedures as appropriate.”²¹⁵ Although the Commission did not explicitly condition its approval of the merger on a requirement that the applicants join the Midwest ISO (the applicants had in fact already filed for approval to transfer control over the operation of their transmission facilities to the ISO), the Commission stated its approval of the merger “is based on continued ISO participation”²¹⁶ and such participation was required for the merger proposal to meet section 203’s public interest standard.

ii. The Midwest ISO

Regardless of whether the Commission expressly conditions the approval of a merger on participation in an ISO, these cases demonstrate, in at least a merger context, the Commission considers ISOs essential to alleviating certain types of market power. As a result of the Commission’s section 203 authority, in those areas of the country where there has been significant merger activity such as the Midwest, there has also been a noticeable amount of ISO activity. For example, on January 15, 1998, nine entities filed a request to obtain Commission approval to establish the Midwest ISO.²¹⁷ However, while the Commission has encouraged participation in ISOs through its conditioning authority in merger proceedings, the drive toward ISO formation in the Midwest has been much weaker than it has been in those areas with existing power pools, where there is a history of coordination, or in those states having mandated ISOs.

For example, unlike the other ISO proposals approved by the Commission thus far, the Midwest ISO filing does not propose to create a

212. *Id.* at 61,402, 61,408.

213. *Id.* at 61,402.

214. 82 F.E.R.C. ¶ 61,308 (1998).

215. *Id.* at 62,223.

216. *Id.* at 62,222-23.

217. F.E.R.C. Docket No. ER98-1438-000.

single control area operator to manage that ISO's grid.²¹⁸ However, the Commission stated in Order No. 888 that its eleven ISO principles apply only to ISOs which are control area operators.²¹⁹ If an ISO is not the control area operator, then the ISO's ability to impartially calculate the available transmission capacity (ATC) and determine on a nondiscriminatory basis who is to use such ATC will necessarily be impaired. The calculation of ATC will depend on the completeness, timeliness, and accuracy of data submitted by integrated utilities. To date, there has been substantial concern that integrated utilities have strategic reasons for posting ATC data which is less than high quality.²²⁰ The Midwest ISO's proposal, in that it does not create a single control area operator, would not resolve the problem of discriminatory ATC calculation and use.

Another disadvantage to the maintenance of separate control access is the loss of the opportunity to internalize loop flows within larger regional transmission systems. Consequently, without the establishment of a single control area operator, the ISO will not have addressed fully those very market power problems that the ISO was designed to resolve, and the individual utilities that are participating in the ISO may be able to continue to use their transmission facilities strategically.²²¹ The real issue for the Commission is not simply to create a nation of ISOs at all costs, but rather to restructure the electric utility industry in such a way as to ensure open-access to transmission services and information. In order to complete the transition to a competitive bulk power market, regional transmission providers must have functional and operational control over transmission facilities. It is unclear whether the Commission's exercise of its section 203 conditioning authority in merger proceedings will prove sufficient to achieve this goal.

4. The Commission's Authority To Mandate ISO Participation As a Remedy for Specific Instances of Discrimination

In addition to its section 203 conditioning authority, the Commission may decide to require ISO participation to remedy specific instances of discrimination. In two recent orders, the Commission found that three public utilities have violated the terms of their open-access tariffs and

218. Under the proposal, the Midwest ISO would have oversight over the control area transmission and generation functions, but would not balance load and generation. "The [Midwest] ISO's current structure is essentially a decentralized control area system composed of each utility's control area . . . under the control of the ISO that will not physically pull the switches or perform other similar action." Howard Buskirk, *State Disagreements On Midwest ISO Put FERC In Hot Seat*, THE ENERGY DAILY, July 1, 1998 (citing the Public Service Commission of Wisconsin).

219. *Id.* at 31,730.

220. Petition for a Rulemaking on Electric Power Industry Structure and commercial Practices and Motion to Clarify on Reconsideration Certain Open-Access Commercial Practices, (Mar. 25, 1998), in F.E.R.C. Docket No. RM98-5-000.

221. This use is limited, of course, by the functional unbundling requirements of Order Nos. 888 and 889.

ordered these utilities to take appropriate remedial measures. In *Morgan Stanley Capital Group v. Illinois Power Co.*,²²² Morgan Stanley brought a section 206 complaint against Illinois Power alleging that Illinois Power had failed to accurately post its ATC on OASIS, and had awarded capacity in a discriminatory manner in favor of its own bulk power marketing affiliate. The Commission concluded that Illinois Power had in fact violated the terms of its open-access tariff by: (a) granting its own request to access resources that do not meet the requirements for network resources; (b) failing to consider redispatch of its system instead of denying Morgan Stanley's request for annual service; and (c) failing to offer and provide the portion of Morgan Stanley's requested service that it could accommodate without redispatch. The Commission directed Illinois Power to recompute its ATC without its invalid network resource designations and to reconsider Morgan Stanley's request for service for the portion of requested service which it could accommodate.²²³ While the Commission did not require Illinois Power to participate in an ISO as a means of remedying the utility's violations, it used the context of the specific complaint proceeding as an opportunity to discuss how an ISO would resolve similar tariff violations in the future:

[A] properly structured ISO or other transmission entity can eliminate the potential for the strategic use of a transmission owner's priority to use internal system capacity for native load. The ISO or other transmission entity can also eliminate the incentive to engage in strategic curtailments of generation that a transmission operator's generation service competitors own and can remove any incentive to game OASIS operations.²²⁴

Similarly, the Commission addressed section 206 complaints filed by Wisconsin Public Power Inc. (WPPI) against Wisconsin Public Service Corp. (WPS) and Wisconsin Power & Light Co. (WP&L).²²⁵ As to WPPI's complaints against WPS, the Commission concluded that the utility violated its open-access tariff by: (1) denying WPPI's request for service based on its assertion that the service would violate certain agreements between WPPI and another utility; and (2) improperly calculating its ATC to favor its own merchant function. The Commission ordered WPS to release the capacity it had improperly reserved for its merchant function and to recalculate its ATC in accordance with its open-access tariff. The

222. 83 F.E.R.C. ¶ 61,204 (1998).

223. In an order granting Illinois Power's emergency motion for clarification in the *Morgan Stanley* proceeding, the Commission concluded, after reviewing information subsequently provided by Illinois Power, that it would not require Illinois Power to remove 360 MW of firm power purchased from the Tennessee Valley Authority from its ATC calculation. Through a reporting error, Illinois Power had failed to include this 360 MW as a firm purchase on its F.E.R.C. Form 1. *Morgan Stanley Capital Group v. Illinois Power Co.* 83 F.E.R.C. ¶ 61,299 (1998). However, this subsequent order granting clarification does not affect the Commission's finding in the previous *Morgan Stanley* order regarding remedial measures for section 206 complaints involving public utility violations of the *pro forma* tariff.

224. 83 F.E.R.C. at 61,913 n.11 (citing *Louisville Gas & Elec. Co.*, 82 F.E.R.C. ¶ 61,308, at 62,222 n.39 (1998)).

225. *Wisconsin Pub. Power Inc. v. Wisconsin Pub. Serv. Corp.*, 83 F.E.R.C. ¶ 61,198 (1998).

Commission also concluded WP&L violated its open-access tariff by providing preferential treatment to its merchant function, and ordered WP&L to recalculate its ATC and make capacity available on a first come, first serve basis. Citing the same language as it used in *Morgan Stanley*, the Commission noted that neither WPS nor WP&L participate in an ISO, but that such participation "could help solve the problems presented here."²²⁶

In discussing these two cases at a Commission open meeting, Chairman Hoecker raised the question whether "there is trouble in open-access paradise or these are isolated cases" and questioned whether these complaints indicate that the assumptions underlying Order No. 888 (namely, that functional unbundling is a sufficient mechanism to achieve workable competition in the bulk power market) are correct.²²⁷ Chairman Hoecker also noted that, while the Commission did not follow this route in its orders in these proceedings, one of the Commission's remedies for such *pro forma* tariff violations may, in the future, be to require that the violating utility participate in an ISO. He warned that the Commission "will act more decisively in the future if problems like this become more frequent, and certainly if they become endemic."²²⁸ Commissioner Massey similarly concluded that if WP&L and Illinois Power had been ISO members, then the problems underlying these complaints would not have occurred.²²⁹

In her comments on these two complaint proceedings, however, Commissioner Bailey avoided any suggestion that an ISO mandate would be an appropriate remedy in future section 206 complaint proceedings. She stated that the Commission's remedial measures in *Morgan Stanley* and *Wisconsin Public Power* "represent a sufficient deterrent to other transmission providers that might be tempted to favor their own wholesale merchant function to the detriment of unaffiliated transmission customers."²³⁰ She concluded that she does "not see the need for additional remedial measures or commitments in these orders."²³¹ Nevertheless, the comments by Chairman Hoecker and Commissioner Massey suggest that the Commission may, in future complaint proceedings, expressly order ISO participation as a remedy for open-access tariff violations.²³²

226. *Id.* at 61,861.

227. *F.E.R.C. Finds That Three Utilities Violated The Terms of Their Open-Access Tariffs; Chairman Hoecker Warns That If Abuses Appear to Be Widespread, More Decisive Action May Be Warranted, Including Possibly Mandating ISOs*, FOSTER ELECTRIC REPORT, June 3, 1998, at 1 [hereinafter *Foster Electric*] (citation omitted).

228. *Foster Electric*, *supra* note 227, at 1 (citation omitted).

229. *Foster Electric*, *supra* note 227, at 1.

230. *Foster Electric*, *supra* note 227, at 1 (citation omitted).

231. *Foster Electric*, *supra* note 227, at 1.

232. The Commission has recently issued a Notice of Proposed Rulemaking (NOPR) in which it proposed revisions to its procedures for handling complaints filed at the Commission under Rule 206. F.E.R.C. Docket No. RM98-13-000 (July 29, 1998). The Commission's NOPR is based on the premise

5. The Goal of Restructuring and the Role of ISOs and ITCs.

Since the Commission issued Order No. 888, few utilities have demonstrated an active interest in voluntarily participating in an ISO. As discussed above, the Commission may decide to exercise its authority under various sections of the FPA (such as through a section 203 merger proceeding or a section 206 complaint proceeding) to encourage or require such participation. However, the exercise of such authority is not without its problems. For example, the Commission's conditioning authority under section 203 to encourage ISO participation extends only to those parties specifically before it in a merger proceeding, e.g., the Commission may not require a neighboring utility to participate in an ISO, even if that utility's non-participation will leave a hole in the middle of the ISO, resulting in the so-called "Swiss cheese" effect.²³³

One potential problem with the Commission's encouragement of ISOs is that such encouragement may actually discourage ITC formation. As discussed above, there may be instances in which an ISO is the preferred method of ensuring nondiscriminatory open-access to transmission services and information. However, there are also instances in which a utility may choose, based on its own considerations of economic self-interest, to divest its transmission assets rather than to participate in an ISO. The Commission's policy should not be to require ISOs to the exclusion of other methods of independent transmission operation. After all, the final goal of restructuring is not necessarily to create a nationwide network of ISOs, but rather to create a workably competitive electric wholesale market.

Some commenters have asserted that, although a network of ISOs may not be the desired end result of the restructuring process, the Commission should nonetheless continue to actively encourage ISO formation as a step in the right direction.²³⁴ This view assumes that although ISOs may not be the most desirable alternative, they are presently the most expedient alternative, and that the existence of ISOs will not necessarily hinder the formation of other more preferable regional transmission providers in the future.²³⁵ These commentators suggest that

that the current complaint procedure is insufficient to resolve complaints in an expeditious manner.

233. "The failure to include all transmission in an ISO would result in a piecemeal marketplace that is not truly economic, not fair, and ripe for discriminatory practices." Written Comments by Otter Tail Power Co., *in* F.E.R.C. Docket No. PL98-5-000, at 2.

234. David A. Svanda, Comments on Behalf of the Mid-America Regulatory Commissioners Before the Indianapolis, Ind. ISO Conf. (June 4, 1998), *in* F.E.R.C. Docket No. PL98-5-000, at 12. (stating that "[w]e believe that [the Commission] should send the message that ISO's are necessary now even if it is later determined that a better structure will evolve Waiting for a more perfect structure without some action now to eliminate panicking, improve communications and maintain reliability, will lead to gridlock. In this era of uncertainty and change, we cannot expect a solution that will work forever. What works today may not work tomorrow. In this context an [sic] ISO structure may well be a transitional structure.").

235. It has been suggested that the existence of an ISO that independently operates the transmission facilities might actually facilitate the emergence and expansion of ITCs. Dr. Peter Fox-

the lead time for ITCs would be significantly longer than for ISOs, and, in the meantime, the industry requires a network of regional transmission providers as quickly as possible.²³⁶

On the other hand, ISO critics suggest it may not be efficient to concentrate on establishing ISOs as a temporary measure when ITC formation is an attractive corporate restructuring option. Because an ITC can be built on the existing systems and processes of the transmission owners, an ITC may actually prove to have less startup costs and require less lead-time than an ISO.²³⁷ In addition, because ISOs may only be temporary structures, they may result in the delay of the development of a more desirable regional ITC.²³⁸

The Commission runs the risk of promoting ISO formation and participation so vigorously in its attempt to foster competition, it may actually interfere with the creation of a "workably competitive market." If the Commission sets its sights too strictly on ISO participation as an end in and of itself, and not merely as a method of reaching competition, the result might well be a delay in the transition to a competitive power market. If it is acknowledged from the outset that ISOs are not intended to be the final solution to the problem of nondiscriminatory open-access, then there is no reason why all utilities should be required to join ISOs. Both ISOs and ITCs can be designed to reach this end by regionalizing the transmission grid, eliminating rate pancaking, and assuring nondiscriminatory open-access.

IV. CONCLUSION

Achieving competition is the true goal of restructuring, and many observers believe ISOs may only be a "transitional vehicle" on the road to this end. These commentators suggest that ISOs may simply be one mechanism by which to regionalize the transmission grid, eliminate pancaking, and provide open-access, and that the formation of ITCs will be the ultimate result of restructuring. In light of the problems associated with ISOs, any new Commission policies regarding ISOs should consider

Penner, Comments Before the Indianapolis, Ind. ISO Conf. (June 4, 1998), in F.E.R.C. Docket No. PL98-5-000, at 48.

236. John Procario, Comments on Behalf of Cinergy Services, Inc. and the Midwest ISO Management Council Before the Indianapolis, Ind. ISO Conf. (June 1998), in F.E.R.C. Docket No. PL98-5-000, at 18.

237. NSP suggests that both ISOs and ITCs should be able to become operational within two years. NSP Comments, *supra* note 41, at 18.

238. Henry Janhsen, Comments on Behalf of Southwestern Public Service Co., New Orleans, L.A. Before the ISO Conf. (June 1, 1998), in F.E.R.C. Docket No. PL98-5-000, at 94. (stating that "Southwestern would like a better sense that ISOs will be viable in the long term, and not simply some expensive interim step to some other industry structure."). See also Anthony Alexander, Comments on Behalf of First Energy Corp. Before the Indianapolis, Ind. ISO Conf. (June 4, 1998), in F.E.R.C. Docket No. PL98-5-000, at 96 (stating that a utility within an ISO may be prohibited from divesting its transmission assets to an independent transmission company unless that company also wants to be part of the ISO).

that many roads lead to Rome, and that the encouragement of ISOs to the exclusion of ITCs may not be the most effective route to achieving competition in the electric industry. The Commission should consider the application of incentive-based rates to encourage other forms of corporate unbundling. Consequently, while the Commission should continue to encourage ISOs, it should also encourage other vehicles which may be more palatable to market participants, such as ITCs.

