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THE QUEST FOR AN INVENTIVE UTILITY REGULATORY AGENDA

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I. INTRODUCTION

The electric and natural gas utility industries of the United States are on the threshold of a transformed marketplace. Technology and competitive alternatives to traditional service are paving the way for customer choice with greater risks and rewards for the industry. In that spirit, economic efficiencies and conduct that furthers competition and improves customer choice should be encouraged. My purpose here is to compel the utility industry, regulators, stockholders and consumers to take a second look at the regulatory framework of today's utilities to ensure the most efficient service at the lowest cost to the consumer.

I begin by discussing the present day issues confronting the electric utility industry and how incentive rates would provide better, more efficient outcomes. I include a brief account of an incentive-based rate plan that the Mississippi Public Service Commission adopted while I served there. The experience in Mississippi shows opportunities and choices for the regulatory process that provide alternatives for the industry and the consuming public. Finally, I give a brief account of how incentive rates might work in the natural gas industry.

I hope thereby to begin a timely debate. Discussions are intensifying on the direction in which the energy industry should head. Much thought is taking place on alternative and inventive forms of regulation. However, the thought that leads to no action is not thought, it is dreaming. Dr. Alfred Kahn has taught us that "Regulation is a substitute for competition

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and competition is a substitute for regulation."[1] This teaching being so, if we are moving towards one (competition), we should be moving away from the other (regulation). I query, are we doing as we have been taught? I suggest we should be doing more.

II. INCENTIVE RATES FOR ELECTRIC UTILITIES

The case for incentive rates in electricity is more compelling in the electric industry than in the gas industry.[2] Without claiming it as a panacea, I think that the approach would go a long way toward solving the series of complex problems that regulation hid, but the move toward competition has revealed. These problems fall under three related topics: system operation, reliability and transmission pricing. Throughout this section, I group the issues into those three categories.

A. *The Need for Alternative Regulation*

In Order No. 888, the FERC outlined at length the evolution of the electric utility industry from its inception until the threshold of competition.[3] From the details, the following picture emerges. By definition, electric companies exist to sell power. Throughout most of their history, utilities did so by building generating plants close to their customers. Even as the local entities consolidated financially into holding companies, operationally they remained islands unto themselves. That reflected the state of technology at the time.[4] If transmission entered anyone's mind, it did so as an incidental service.

Eventually, utilities saw the light[5] and began to take advantage of the efficiencies that the economics of transmission offered: the ability to build fewer (mostly bigger) generating plants; the possibility of pooling reserves; the chance to locate plants closer to the fuel source (for example, coal), rather than the customer; and the like. Until the 1980's, transmission played a subordinate role to generation. That, vertical integration, and cost-of-service regulation helped obscure subsidiary issues from public view. While not as glamorous as safety and the environment, these considerations play an important role in the success of electric policy, in the form of good service to customers.

Many of the burning issues of today existed in the past, but utilities

1. Dr. Alfred Kahn, Speech before the FERC, Chairman Hoecker's Distinguished Speaker Series (Feb. 18, 1998) (notes of the author).

2. The FERC has basically allowed market-based rates for generation. The incentives we advocate here relate to transmission, an activity that most observers agree will remain highly regulated.

3. 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. ¶ 31,036, at 31,639-652, 61 Fed. Reg. 21,540 (1996) (codified at 18 C.F.R. pts. 35, 385) [hereinafter Order No. 888].

4. For that reason, when Congress passed the Public Utility Holding Company Act to control abuses of holding companies, the law required integrated operation as one criterion for continued existence. 15 U.S.C. § 79k(b)(1) (1994).

5. In large measure, the Northeast Blackout of 1965 made them aware of the need.

could afford to ignore them altogether, solve them informally or "add them to the customer's tab," as we now see.

1. System Operation

Transmission expansion presented only a minor issue because utilities for the most part relied on building generating plants, and customers did not have a choice among suppliers. The transmission grid was not as heavily used as it is now. While state siting laws made construction difficult, the systems were getting by. Utilities operated control centers. Because each could be in a position of needing help from the others, companies acted in a non-discriminatory fashion in their dispatch decisions.[6]

Inadvertent power (loop) flows that occurred when electricity traveled outside the contract path did not require compensation. Utilities inflicted these flows on each other, and the amount involved rarely rose to significance. Because of cost-of-service regulation, utilities could ignore the effect on the "bottom line."

Ancillary services (electricity for reserves in emergencies) and power needed to keep the grid working formed part of the costs utilities wrapped into the rate, along with the utility's other costs. The existence of vertical integration meant a lack of competition for the provision of these services. This led to the lack of attention paid to this issue by regulators and customers.

2. Reliability

As with other regulated industries in which competitive pricing did not exist (such as airlines), companies put a premium on quality: meals on flights and reliability in the electric utility industry. Therefore, for all practical purposes, customers could take reliability for granted. With integrated utilities as the major participants in the market, rarely did a question arise as to whether utilities enforced excessive reserve requirements.

When a controversy did occur, the issue came up in the context of a holding company in a rate case establishing reserves as part of the compensation companies with surpluses received from members deficient in that regard. Otherwise, reliability councils or the states established requirements and everyone assumed this exercise lay beyond the FERC's jurisdiction.[7]

3. Pricing

Historically, cost-based rate making prevailed. In the era before Or-

6. *See, e.g., Central Iowa Power Cooperative v. FERC*, 606 F.2d 1156 (D.C. Cir. 1979), in which the court used that rationale to find that members of power pools lack market power and, therefore, the Mid-Continent Area Power Pool agreement did not violate the antitrust laws.

7. *Central & South West Services, Inc.*, 49 F.E.R.C. ¶ 61,118, at 61,502 (1989) ("we believe that the individual operating companies are ... best guided by the reliability groups in which they operate and by the individual state commissions ...."); 49 F.E.R.C. at 61,504 (1989) (Trabandt, Comm'r, concurring) ("the Commission has no ... intent" to regulate reliability).

der No. 888, the FERC never approved another formula, except on an experimental basis.[8]

4. Restructuring

The move toward competition, especially the issuance of Order No. 888, brought major change to the industry. In addition, the enlargement in the scope of economic markets and technological improvements increased the distance over which buyers and sellers transacted. In turn, the new market requires a new philosophy of regulation. With new entrants and the movement away from vertical integration, the milieu of informal understanding as the means for resolving issues gave way to contracting and the need for structured organization. No longer would utilities accommodate each other with the knowledge that their fellow members of the club would reciprocate on another occasion when the roles of supplier and supplicant reversed.

Moreover, in this setting, the new entities, generators and marketers, including brokers, remained dependent on their competitors—transmission utilities that also owned generation—for economic survival. Other factors, including failed investment in nuclear generation, placed greater importance on making due with existing units. That placed more pressure on the transmission grid as the nerve center of the electric industry.

5. Order No. 888

In effect, the trade-off for restructuring amounted to deregulation of generation alongside more vigorous regulation of transmission. Order Nos. 888 and 889 reflect that decision.[9] The FERC made the *pro forma* open access tariffs the centerpiece of the restructuring. This enables companies to compete as sellers in the market only in the business of generation, marketing, or brokerage.[10]

Without having a direct stake as an owner or operator of transmission, these sellers would more likely tend to favor no-frills transmission, even to the extent of becoming free riders. In addition, as competitors to the generation portion of the business of integrated utilities, these new entrants have every motive to challenge, on competitive grounds, the existing ways of doing transmission business.

Another impetus toward factionalism in the industry came from the requirement in the open access rule that power pools must establish "nondiscriminatory" criteria for companies to join. As a result, pools, which where comprised of transmitters only, had to open their membership to other entities—generators, marketers, brokers, and customers—with com-

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8. *See Western Systems Power Pool*, 55 F.E.R.C. ¶ 61,099, at 61,300-01 (1991).

9. Order No. 888, *supra* note 3, at 31,652.

10. The other side of the coin—that companies would operate as transmitters only—forms the linchpin of the idea we advocate as the wave of the future in the transmission business: separate grid companies with incentive rates.

peting perspectives.[11]

Not only did the new entrants have a reason to question expenditures for reliability or expansion, the FERC gave them a seat at the table from which to express their opposition. In effect, operation of the transmission grid would become like government by committee, where everyone's interest must be satisfied at least to some degree. This process leads to compromises that may be worse than picking the "wrong" solution. In matters that do not command immediate attention, such as long-term investments in the grid, the clashes between owners and customers may become intense. Yet, finding the right answer becomes vitally important.

In addition, Order No. 888 introduced a major change by ordering "functional unbundling."[12] Previously, when utilities sold electricity at wholesale, they charged one rate that not only included generation and transmission, but also all the underlying services. Now, utilities would separate costs for backup facilities, reliability, and electricity that the transmission grid uses in moving the power to its destination (ancillary services).

Besides allowing the customer to see each charge as a separate item on the bill, the purchaser would have redress. The FERC required the transmission utility to allow three choices in obtaining some types of ancillary services from: the transmission company, competing entities, or self-generation.[13] In one fell swoop, the FERC tore the roof off the tent within which utilities glossed over such potentially contentious issues as compensation for loop flows and paying for the costs of reliability. No longer could utilities afford to abide by their gentlemen's agreement. Just as in the telephone industry, where competition put an end to the practice of long distance subsidizing local services, restructuring required new economic arrangements between utilities and customers.

Order No. 889 also influenced the trend toward the breakdown of the traditional consensus.[14] Ostensibly, the OASIS rule dealt with posting information on the Internet in the form of Codes of Conduct. Underneath lay another fundamental change in the way the industry functioned and one which increased the pressure for abandoning the old methods. In particular, the Code of Conduct directs separation between transmission and marketing arms of integrated companies.

In turn, posting information about business opportunities allows other sellers to compete for the sale. It also creates incentives to keep costs at a minimum. In order to do so, utilities will not readily spend money on "hidden" items such as system operation and reliability. The idea of separation

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11. Order No. 888, *supra* note 3, at 31,727.

12. *Id.* at 31,653-56.

13. *Id.* at 31,715-17 (customers have choice in obtaining three ancillary services: regulation and frequency response; energy imbalance; and reserves).

14. Order No. 889, *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct*, F.E.R.C. STATS. & REGS. ¶ 31,035, 61 Fed. Reg. 21,737 (1996) (codified at 18 C.F.R. pt. 37).

also leads to opportunities for complaints about alleged favoritism on the transmission grid.

Finally, as discussed later in detail, Order No. 888 recognized that competition necessitated changes in thinking about the organization of the grid and transmission operations. The Commission chose not to prescribe a particular type of ownership and control, leaving it up to utilities to choose. The thrust of Order No. 888, however, pointed towards Independent System Operators (ISO), for the FERC "encouraged" their formation. To that end, the Order listed "principles" that would ensure the FERC's approval of an ISO. These principles refer to fairness, inclusiveness and dispute resolution. This concept was alien to the old way of doing business and a departure from pure economic considerations.[15]

In contrast to the historical situation, the following now prevails in each of the three areas of interest listed previously.[16]

6. System Operation After Order No. 888

Transmission expansion becomes a major issue because utilities rely on using generating plants to serve load. Because customers have a choice among suppliers, the transmission grid must experience heavy use. State siting laws have made construction difficult. Add that to the fact that new entrants, as competitors of transmission owners, question the methods and decisions of the grid's operator-utilities.

The new tension within the electric industry, between integrated companies and new entrants and between suppliers and wholesale customers, spills over into the operation of control centers as well. Do competitive considerations, rather than those of objective engineering, determine dispatch decisions? In that regard, note the controversy in California over must-run (for reliability) plants and how the utilities designate them.[17]

Inadvertent power loop flows represent a cost that the utilities must pay heed to, from a competitive point of view. Sellers cannot ignore the fact that the utilities, over whose lines the power flows, lose revenue belonging to them and see rivals earn undeserved money. In addition, the need for accurate pricing requires transmission companies to include loop flows in rates.[18]

Ancillary services, like the flights to small communities after airline deregulation, no longer enjoy a hidden subsidy. Regulators must find ways to encourage generators to offer them, such as by allowing market-based rates.[19]

15. Order No. 888, *supra* note 3, at 31,730-32.

16. *See supra* pp. 3-4.

17. *California Independent System Operator*, 82 F.E.R.C. ¶ 61,236 (1998), describes the efforts in California to designate must run units and the requirement for informational filing at the FERC.

18. *Inquiry Concerning the Commission's Pricing Policies for Transmission Services Provided by Public Utilities Under the Federal Power Act*, F.E.R.C. STATS. & REGS. ¶ 31,005, at 31,146-47, *order on reconsideration*, 71 F.E.R.C. ¶ 61,195 (1995) [hereinafter Pricing Policy Statement].

19. In *Ocean Vista Power Generation, LLC*, 82 F.E.R.C. ¶ 61,114 (1998), the Commission estab-

7. Reliability After Order No. 888

Customers can no longer take reliability for granted, since price competition gives companies incentives to cut costs. Questions arise from competitors, customers that have become more price conscious, and regulators about whether utilities enforced excessive reserve requirements. The FERC and the Department of Energy have begun consideration of whether reliability councils or the states that historically established requirements need supplementation by legislation or an assertion of the FERC's jurisdiction, assuming it has any. Those deliberations resulted in the Administration's Comprehensive Electricity Competition Plan proposing that Congress "require" the FERC to "approve and oversee a self-regulating organization" that would set mandatory standards and that utilities must join.[20]

8. Pricing After Order No. 888

The FERC never approved a formula besides cost-based rates. The Commission recognized, however, that the new order may call for other methods.[21] I submit that incentive rates fits within the new approach.

In the rest of this part, I address the issues in each of these areas and why the FERC must adopt incentive rates.

B. New Ideas and Their Problems

1. System Operations

As far back as 1992, in the debate over the Energy Policy Act, the industry realized that grid operation would have to change as competition began to take hold. In fact, a provision for Regional Transmission Groups (RTGs) almost made it into the law.[22] Proposed as section 216 of the Act, what the FERC later called the "consensus proposal" would have allowed members of the electric industry—generators, transmitters, and wholesale customers - "with an interest in" transmission services in the region to join the RTG. The participants would operate the grid, maintain reliability, plan for and pledge expansion when necessary and settle disputes.[23]

The proposal contained at least two incentives to ensure success, one explicit and the other implicit. Section 216 (b) (3) allowed RTGs to exempt their members from the FERC's wheeling orders under section 211—the explicit carrot—and section 216(a)(1)(G) gave members flexibility in transmission prices by stating that they must be consistent with the

lished guidelines for applicants seeking market-based rates for ancillary services. In short, the FERC requires a showing of a market in the particular service and how the applicant's market share falls within acceptable levels.

20. Department of Energy, *Comprehensive Electricity Competition Plan* (1998) at 12.

21. Pricing Policy Statement, *supra* note 18; Order No. 888, *supra* note 3, at 31,666-67.

22. J. Z. Rokach, *Antitrust in the Electric Utility Industry: Regional Transmission Groups*, 14 J.L. & COM. 39 (1994).

23. *Id.* at 47-48.

Energy Policy Act, rather than just and reasonable or cost-based—the implicit carrot.[24]

With the failure of the consensus proposal, the FERC issued a Policy Statement Regarding Regional Transmission Groups.[25] The statement made three blunders, one by subtraction and two by addition, to the consensus proposal that we must now remedy through incentive rates for a private transmission entity. In particular, the FERC shredded the carrots, as it removed the provision exempting RTG members from wheeling orders. In its place, the Commission gave a vague assurance of some sort of deference to an RTGs alternative dispute resolution.[26]

In this way, a powerful reason for the transmission utilities to join RTGs fell by the wayside. Component 4 required the RTG to "incorporate the needs" of non-members.[27] Here, the Policy Statement constructed a further obstacle to the effectiveness of RTGs. Under the consensus proposal, those not members risked being left out. By requiring the organization to take needs of non-members into account, the Commission now made it easier to stand on the outside looking in and become a free rider.

The FERC added a requirement that RTG members consult and coordinate with the states.[28] As we see in our discussion of ISOs, this created a real potential for paralysis. While well intentioned, this provision, combined with the requirement for "fair governance," led to the creation of the cumbersome superstructure that may sink effective operation of the grid.

In Order No. 888, the FERC expanded the notion of RTGs into that of independent system operators (ISO). The eleven ISO principles that the FERC promulgated show the practical difficulty in accomplishing the goals the FERC envisioned for these organizations. Principle 4 states that ISOs should have responsibility for reliability, while Principle 7 requires that they create incentives for efficient management of the grid. Yet, at the same time, Principle 1 states that ISOs must operate independently of the users of the grid.[29]

In fact, the ISO must prevent "control and appearance of control" by any class of user.[30] If the FERC concerned itself with the ISO being a vehicle for economic domination, to the detriment of competition, Order No. 888 should have required the ISO to operate for the benefit of all consumers. By removing control from any one group of users, the ISO principles either put everyone in charge or no one. The FERC removed accountability, a necessary ingredient in operating any enterprise.

24. *Id.* at 48.

25. Policy Statement, *Policy Statement Regarding Regional Transmission Groups*, F.E.R.C. STATS. & REGS. ¶ 30,976, 58 Fed. Reg. 41,626 (1993).

26. *Id.* at 30,877-78.

27. *Id.* at 30,875.

28. *Id.* at 30, 874 (Component 2).

29. Order No. 888, *supra* note 3.

30. *Id.* at 31,731.

In addition, Principle 2 requires that operators relinquish financial interests in the grid. The ISO must establish strict rules for conflict of interest rules and arms length transactions with the transmission owners.[31] Here, Order No. 888 neutralized the profit motive, the main engine of the success of free enterprise. Not-for-profit corporations have a place in a capitalist economy. No one has made the case for such an arrangement in transmission, a private business that requires large expenditures and risk-taking.[32]

Finally, in a retreat from the consensus proposal, Principle 11 encourages the ISO to form a mechanism for alternate dispute resolution, but offers no word of deference from the FERC, let alone exemption from the FERC processes.[33]

The ISO principles created cumbersome structures. In the immediately preceding issue of the *Energy Law Journal,* Barker, et al., discuss system governance across the world.[34] I draw the following conclusion: a totally disinterested management deprives the ISO of necessary expertise in fulfilling the goals of maintaining reliability and creating incentives for efficient management of the grid.

By the same token, creating a two-tiered system, with the operators having expertise and an oversight board with outside parties, has difficulty of its own. Cumbersome administration becomes the substitute for ignorance. Giving governance to all classes of participants—transmitters, generators, customers and states—creates paralysis. In addition, arguments arise for and against weighted voting, one-class veto, or super majority voting, as these arrangements must entail. If one adds the necessity for regulatory oversight, appellate jurisdiction, and standard setting, the potential for a complex and inefficient structure becomes very real.

The Secretary of Energy Advisory Board's (DOE Advisory Board) description of the functions the ISO must perform shows the grave consequences of an organization established on mistaken principles. The severance of control from ownership inherent in an "independent" operator forces the ISO to convince the transmission owners to obtain permits and undertake—namely, pay for—construction (and maintenance) of the grid's facilities.[35]

In addition, according to the DOE Advisory Board, the ISO must accurately implement reliability standards; perform system security measures; re-dispatch the grid in emergencies; enforce penalties;[36] and, in some

31. *Id.*

32. The Appendix to the February 26, 1998 draft paper from the Secretary of Energy Advisory Board Task Force on Electric System Reliability (DOE Advisory Board) states that "Operating and Planning staffs will require heavy-duty system operations and planning skills [in] transmission planning."

33. Order No. 888, *supra* note 3, at 31,832.

34. J. Barker, Jr., et al. *Regulation of Power Pools and System Operators: An International Comparison*, 18 ENERGY L.J. 261 (1997).

35. DOE Task Force, at II. B. 4.

36. *Id.* at II.C. 1.

cases, underpin the market by defining available capacity and performing scheduling activities.[37] More than that, the ISO would file a tariff and set transmission rates, in the vision of the DOE Task Force's February draft paper.[38]

Experience thus far with ISOs has shown some shortcomings of the idea. Just weeks ago, on April 15 and 16, the Commission conducted a conference on this subject. One idea stood out in the exercise: on its own, the ISO has a long way to go before solving the practical problems inherent in the concept. In fact, many fundamental questions remain about ISOs and either Congress (not very likely) or the FERC (not very easily) may have to use legal mandate or regulatory muscle to give these organizations a big push into being.

The Notice of Conference the FERC issued on March 13, 1998, in PL98-5-000, shows how complex it would be to establish a working ISO, if that goal even remains possible. The Commission divided the participants into seven panels on these topics: basic structure and role; regulation, governance and independence; role of the states; reliability; transmission pricing; market monitoring and the FERC regulation.

These panels discussed questions contained in a seven-page staff appendix. The appendix covered such basic issues as how to induce formation of ISOs. Forcing mechanisms ranged from requiring ISOs as a condition of mergers to holding that section 206 of the Federal Power Act, which prohibits undue discrimination, allows the FERC to compel the industry to join.[39]

In addition, several panels spoke about how to ensure that the ISO carries out the responsibilities the FERC assigns to it. To panel 4, for example, the Appendix to the Notice of Conference asked whether the Commission should write rules giving ISOs access to reliability information and meshing their roles at wholesale with retail reliability.[40]

All represent thorny problems the FERC must solve. Resolution requires detailed FERC involvement in the affairs of the industry. Government should avoid putting itself in such a position, unless there is no alternative. However, one does exist: the transco or grid company.

As doctors Vernon Smith and Stephen Rassenti pointed out in their paper, "[w]ith [a separate company owning transmission and distribution] the potential questions [of market power that lead to the ISO] would be eliminated. Generation entities would be free to apply power . . . as the markets develop. The remaining [grid] companies would schedule power . . . to minimize costs for customers . . . ."[41] The issues that perplex the industry and regulators on ISOs would evaporate. The incentive

37. *Id.* at II. D.

38. *Id.*

39. Docket No. PL98-5-000, Notice of Conference, Appendix at 7.

40. *Id.* at 4.

41. Vernon, Smith, and Steven Rassenti; Market-Driven Restructuring: Accelerating the Deregulation of Electricity 7 (May 20, 1996) (manuscript on file with author).

would exist to create companies of the proper size and with the most qualified personnel as managers and dispatchers. The grid company would have no reason to favor particular generators, as it would have nothing to gain. In addition, the grid company would schedule and curtail without regard to the source of generation, since the generator would not own any part of the grid.

Price remains the one area that requires regulation. If a transco or grid company operates independently of generators, it still possesses a monopoly over transmission. As discussed in section C, incentive rates would give the monopoly a restraint against excess, with minimal regulatory oversight. This situation so far represents the experience in Mississippi, which is also described.

2. Reliability and Complaints About Customer Service

In addition to ISOs as against grid companies, the great issue at the FERC currently involves reliability. As mentioned earlier,[42] before competition, customers and regulators had little reason to worry about reliability. With the changes in the industry, that no longer remains the case. Both the FERC, under its rate setting authority in section 205, and the Department of Energy, which bears responsibility for reliability under section 202(a) of the Federal Power Act,[43] must increase their efforts in that regard. This will require incentive rates with substantive standards and new institutional arrangements.

The FERC recently conducted a conference of interested parties, a "roundtable" on reliability. The conference considered three alternate arrangements: filing a tariff at the FERC, similar to the open access tariff of Order No. 888; relying on complaints from customers; and requiring utilities to establish standards through declaratory orders. Each of these involve the FERC. As Deputy Secretary of Energy Moler testified, the legal authority of the FERC in the area remains "unclear," at best.[44]

Chairman Hoecker stated at the conference that he thought it imperative for Congress to legislate in the area to augment the FERC's authority.[45] He maintained, as did the Deputy Secretary of Energy, that the current system of the North American Electric Reliability Council's (NERC) voluntary standards no longer work.[46]

On that score, the testimony proved them right. Customers and new entrants argued with utilities, customers and new entrants emphasized allegedly anti-competitive motivation, while utilities argue about safety of

42. *See* discussion, *supra* p. 5.

43. 16 U.S.C. § 824a(a) (1994).

44. Processes for Assuring Non-Discriminatory Transmission Services as New Reliability Rules Are Developed for Using the Transmission System, Docket No. PL98-3-000, Reliability Roundtable, Transcript at 13 (Feb. 20, 1998).

45. *Id.* at 8.

46. *Id.* at 8, 147 (Chairman Hoecker); *Id.* at 13 (Deputy Sec. Moler).

the grid.[47] Chairman Hoecker correctly expressed his concern about whether the FERC had the resources (and, in our view, the expertise) to undertake such a large job.[48]

The NERC itself has entered the arena. On December 22, 1997, the NERC, in co-operation with Florida State University, convened a reliability panel, and issued its findings.[49] The report suggested a hybrid approach, similar to the private securities market. The North American Electric Reliability Organization (NAERO) would act as a self-regulating body, subject to the supervision of proper governmental bodies. The Administration's Comprehensive Electricity Competition Plan endorsed that mechanism.[50]

Problems exist with that recommendation. Even here, superimposing this arrangement on the existing organization of the industry or on ISOs raises many of the same issues the ISO conference grappled with, arising out of the tension between new entrants looking at incumbents as anticompetitive in motivation and the incumbents looking at the new entrants as free-riders.[51]

In addition, giving status to the self-regulating body requires legislation, especially in light of the fears of some utilities about antitrust problems.[52] Moreover, unless the Department of Energy indicates a willingness to use its authority under section 202(a) of the Federal Power Act to designate co-ordination districts; and the statute which requires that the designation remain voluntary appears adequate, Congress will have to legislate on the supervision. Congress will not likely act soon.

Customers have begun to question more than just the industry's reliability standards. In at least two formal filings with the FERC, wholesale customers contend that transmission utilities shortchange service through alleged over-booking, withholding capacity for their own needs and scheduling.[53] In its comments on the Symposium on Process and Reform: the Commission's Complaint Procedures, the Electric Power Supply Association urged the Commission to expedite relief in cases of failure of service. In filing, a petition for rulemaking, sixteen parties ranging from large industrial consumers to electricity marketers urged the FERC to enact regulatory changes, such as tightening the Code of Conduct and more

47. *Id.* at 90, 128-29 (Sue Kelly); *Id.* at 120 (Kurt Conger).

48. *Id.* at 144.

49. NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL, RELIABLE POWER: RENEWING THE NORTH AMERICAN ELECTRIC RELIABILITY OVERSIGHT SYSTEM (December 22, 1997) [hereinafter the NERC Task Force Report].

50. *See supra* note 20.

51. The report discusses governance and membership at length. NERC Task Force Report at 22-27.

52. *See, e.g., supra* note 47.

53. Comments of the Electric Power Supply Association, *Symposium on Process and Reform*, Docket No. PL98-4-000 (1998); Petition For Rulemaking on Electric Power Industry Structure and Commercial Practices and Motion to Clarify or Reconsider Certain Open-Access Transmission Practices, Docket No. RM98-000 (filed March 25, 1998).

regulation of the OASIS bulletin board, in addition to structural remedies.

C. A Solution: Incentive Rates

In the new era, the FERC needs to adopt an overarching policy as a means to ensure utility performance in the areas of reliability and customer satisfaction. Moreover, as transmission could remain a monopoly, regulation must assure as well a reduction in prices. In its recent report, the DOE Advisory Board stated:

> Without a robust open market for transmission improvements there is minimal incentive for commercial entities to advance long-term transmission research. Research to advance transmission technology would then be in the public interest and open rather than proprietary. Funding mechanisms for this research will have to be developed.[54]

An incentive rate plan like the one the Public Service Commission (Mississippi Commission) developed with Mississippi Power Company (Mississippi Power) fills that need. In brief, the Performance Evaluation Plan (PEP) places equal weight on lower prices on the one hand (50%) and reliability and customer satisfaction (25% each).[55]

If the FERC finds the right combination of unleashing the economic self-interest of the profit motive and minimal regulatory review, establishing a grid company as the owner-operator of the transmission system would go a long way toward overcoming much of the difficulty with ISOs and the FERC reliability processes. Most importantly, the FERC would use existing authority under section 205 of the Federal Power Act to adopt the plan. Knowing that it could earn a profit from a grid company, the industry itself would voluntarily organize one.

In broad terms, the Commission would set an overall standard. Borrowing from the ISO concept, the FERC would require the grid or transco company to conform to independently set criteria. One commentator suggested using the variations in hourly cycles, or the heat rate of the grid.[56] Another means might involve enlisting the NERC, or a group such as NAERO, as an independent, disinterested expert authority to *establish* standards for the grid company to *implement* through its personnel who operate the grid.

The actual means of fulfilling the standard would depend on the company, but the company would file the plan with the FERC. If the company exceeded the standard, it would reap monetary reward; if short, its shareholders would suffer monetary losses. An annual audit would verify results.[57]

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54. SECRETARY OF ENERGY ADVISORY BOARD TASK FORCE ON ELECTRIC-SYSTEM RELIABILITY, INCENTIVES FOR TRANSMISSION ENHANCEMENT 8 (February 26, 1998) (draft paper).

55. *Mississippi Power Company, Performance Evaluation Plan*, Mississippi Public Service Commission, Docket No. 93-UA-0302 [hereinafter PEP], Appendix B at 8 (1994).

56. Mark Lively, *WOLF Pricing*, PUB. UTIL. FORT., Oct. 1, 1994 at 69.

57. Mississippi Power's PEP calls for a semi-annual evaluation. PEP, at 1.

1. The Plan Behind the Plan

At the infancy of the competitive market for electricity, ensuring proper transmission pricing and the expansion of a transmission grid are of central interest to policy makers and long-term planners. With the growth in transactions, the grid will experience greater levels of constraint. In Mississippi, our Public Service Commission faced these same issues, though in the context of retail service.

We concluded that, in the long run, complex regulatory schemes and codes of conduct could not ensure in a meaningful fashion the levels of reliability our country has become accustomed to, and constituents now require. We looked for a method of pricing and a program for innovation that would make the industry the engine of a successful result. The method would have to provide the carrot of profit in order to achieve the degree of efficiency experienced in the days of informal understandings and accommodations.

We saw no need to consign to the history books our Nation's experience with high levels of performance. To achieve the same results, however, the Mississippi Commission, as I think the FERC, would need to make adjustments in philosophy as well as policy. We regarded as a failing proposition the use of government "expertise" to outwit a monopoly's tendency for anti-competitive behavior. Instead, we relied on the fact that our capitalistic society rewards ingenuity and innovation. Indeed, entrepreneurial spirit, we thought, must form the most important ingredient of regulation, if we were to make a success of Mississippi's utility service. We at the Mississippi Commission concluded that incentive and performance-based pricing would increase customer satisfaction. In the same vein, I think incentive rates must underpin the competitive market Order No. 888 envisioned. On the federal level, I think such an approach in transmission can also provide the means to resolve the regulatory impasse between industry seeking higher return on the investment, and customers claiming that the monopolistic regime of transmission requires cost-based rates with low rates of return.

With additional opportunity for profit, the industry will build the type of transmission grid that will provide the level of reliability required by customers. The lower rates and improved customer service resulting will satisfy the demands of consumers. No matter how rigorously we regulate transmission, if the industry no longer provides a high level of certainty that the product will be delivered as agreed, we will have failed in our efforts.

I think that on the federal level, as in Mississippi, the required level of certainty can be ensured by requiring the grid or transco company to meet articulated standards, in exchange for an opportunity to earn a higher rate of return. The incentives work through a formulary calculation of the revenue requirement, and allow the utility to earn higher profits if it reduces its costs.[58] Another way entails a specific or narrow incentive, such as accelerated depreciation on investment tied to the elimination of system constraints, or attributable to increased reliability.[59] These incentives transform the transmission systems into a profit center which becomes the foundation for the economic success of restructuring.

2. Summary of the Plan

Incentive and performance based plans are carefully researched and negotiated formulas for the determination of the revenue requirements of a utility. Plans can be as different as night and day; however, the intended results are the same. The different components, formulas, indexes and calculations are only limited by the need for a sound basis upon which to determine a fair earned return on investment.

The PEP works as follows. Through the use of the formulary earned rate of return along with an adjustment for the performance of the utility in the areas of price, customer satisfaction, service reliability, this market surrogate permits light-handed regulation. The PEP calculates earned return on investment by using the rate base for the end of the review period and by using the expenditure and revenue items for the preceding historical period. Each of these components (rate base, expenditures and revenue) is separated on the basis of wholesale and retail. Further, each rate class must reach a level of parity analyzed in conjunction with the cost-of-service study filed pursuant to the plan.[60]

The resulting operating income can then be divided by the total rate base in order to determine the after tax earned rate of return. Under an extremely simple explanation of an incentive and performance based plan, the comparison of the earned return on investment to the calculated performance benchmark return on investment would reveal whether the revenue requirement is to increase or decrease during the upcoming period.[61]

Establishing a benchmark return on investment will be a function of the negotiated performance indicators and cost of capital calculations.[62] While the earned return on investment is the threshold calculation, it is the performance based return on investment that provides the incentive. The result of the formula in determining the performance based return on investment is basically an adjustment to the cost of capital of the utility.[63] The adjusted cost of capital comes from the performance indicators of

58. The PEP envisions such a calculation. PEP, Appendix A at 5.

59. One of the industry participants at the Reliability Roundtable advocated allowing accelerated depreciation. Testimony of William Newman, Reliability Roundtable, *supra* note 44, at 127.

60. PEP at 2; PEP at Appendix A.

61. PEP at 1.

62. In Mississippi it happened that way, because the PEP represents a cooperative venture between Mississippi Power and the Mississippi Commission.

63. PEP, Appendix C.

price, customer satisfaction and service reliability.[64]

Design of performance indicators into an objective formula is not limited to the indicators noted. The cost of capital is to be determined using a combination of interest on long-term debt, preferred stock and common equity reflecting the current structure of the utility.[65] While the interest of long-term debt and preferred stock equity can be established through the books, filings and records of the utility, the common stock equity is generally more complex. An annual discounted cash flow model (utility comparison), risk premium model and capital asset pricing model can be utilized as well as other models, and in combination, for a figure reasonably acceptable to the stakeholders.[66]

Next, a determination must be made as how to adjust the cost of capital in a meaningful way to provide the reward and penalty for the performance of the utility. An approach that is balanced when establishing the performance mixture prevents the utility from ignoring a specific component of the performance indicators in an attempt to game the plan.

An improper balance of the indicators can result in unintended consequences. It is obvious that low rates without service reliability or customer satisfaction would not be the desired result. As in a market economy, balancing all factors of the customer demands and needs results in the delivery of the best product or service, and in this case, product and service.

In Mississippi, the indicator of price is calculated by using the average retail price per kWh divided by a regional weighted average retail price per kWh.[67] On the federal level, regional information can be compiled or designed in various ways to obtain an appropriate mix of data. Proper comparisons to achieve the standards are necessary for the evaluation of the performance of a particular utility. Data can be compiled from the Federal Energy Regulatory Commission (FERC) Form 1. The information would be updated annually and would form a common source of utility information. The resulting figure from the price comparison would then be used, along with a linear scale, for the final determination of price performance.

As expected, the price indicator should be weighted more heavily in the final calculation of the adjustment to the cost of capital. Even with reliability being vitally important to all consumers, price is the component of which all consumers are acutely aware.

In Mississippi we determined that service reliability, aside from price, is the paramount component which is taken for granted in the everyday life of the consumer.[68] During the transformation from consumer (ratepayer) to customer, reliability will receive the lion's share of the attention

64. PEP, Appendicies B and C.
65. PEP, Appendix C.
66. PEP, Appendix C.
67. PEP, Appendix B.
68. PEP at 1.

in the regulatory arena, as the gentlemen's agreements are put aside for the competitive advantages awaiting the utilities that are well positioned in the starting blocks. The plan will have to bring the outages of a utility to a level that is satisfactory to the customer base. Analysis of the total time within the test period in which customers experienced interruptions in the service and the number of customers affected provides an excellent indicator of service reliability.

Ultimately, the indicator can be a percentage of the total hours of electrical service or the amount of time during the test period that the customer experienced service interruptions. As other reliability factors become measurable, additions to the service reliability indicator can be devised and useful for the desired standard.

The last performance indicator the PEP discussed is customer satisfaction.[69] Other than direct contact with the customer base and a customer survey, the measurement of satisfaction is largely subjective. Surveys should be closely reviewed to insure the result will have value to the analysis of the utility, and questions should focus on extracting objective information from each customer surveyed.

Once the performance indicators are determined from the variable weighting of the indicators, the cost of capital is adjusted for the performance based return on investment. The comparison of the performance based return on investment to the earned return on investment results in the increase, decrease, or no change of the revenue requirement for the upcoming period.[70] As with any formulary scheme, changes within a certain range are unnecessary and problematic.

In order to minimize the number of rate changes that could result from trying to match the earned return on investment to the performance based return on investment, a band or range of no change is established to avoid nominal or de minimus alterations in the utility rates.[71] The benchmark is the rate of return on investment used to compare the earned return on investment of the utility during the test period. It is the benchmark for a testing period and the treatment of the increases or decreases in the revenue requirement which fall outside of the band or range of no change that receive enormous amounts of attention during the design stages.

This feature of the plan is also referred to as the deadband. Once outside of the deadband, the consumers assert a desire, and many regulatory bodies agree, to share in the benefits of the performance of the utility. Good business judgment and decisions in a fully competitive economic market are, without doubt, the rewards of the entity. However, if the utility is given an opportunity to earn a fair rate of return with reduced risk, the consumer can and should share in some degree, since a portion of the risk has and always will be borne by the consumers of the utility (i.e. dis-

69. PEP at 1.

70. PEP, Appendix D.

71. PEP, Appendix C (contains the Mississippi formula).

tribution). In the event the earned return on investment falls far enough below the deadband to require an increase in the revenue requirement (in excess of 4% annually in the aggregate, or 2% for a review period, taking into account the sharing provisions), then a full hearing is required before the Mississippi Commission.[72] The result of this statutory hearing requirement, if applicable, is to ensure the accuracy of the information used in the performance evaluation and the proper application and interpretation of the plan.[73]

The customer is allowed the unrestricted ability to select the provider of the desired services, who does not bear the risk and should not, therefore, benefit from the performance of the entity. Sharing provisions in an incentive and performance based plan can and should be based on the design of the indicators noted. As the performance indicators show a high level in the areas of price, service reliability and customer satisfaction, the utility can and should retain the lion's share of the earnings above the band. The converse is true if the earnings are below the band. The quid pro quo drives at the very heart of the plan.

As the design of the plan develops, the discussion will turn to whether the revenue requirement for the period in question returns to the benchmark (performance based return on investment), or whether the revenue requirement returns to the bottom of the deadband.

If the revenue requirement returns to top or bottom of the band, the sharing mechanism can serve the intended purpose. It is obvious that returning to the benchmark eliminates the meaningful use of the sharing design of the plan. Sharing provisions can in some respect weaken incentives unless the performance indicators materially reflect the bottom line revenue to insure the integrity of the rate design.

The results of an incentive and performance based plan can be seen in the history of the PEP. Mississippi Power's average retail cents per kWh dropped from 5.51¢ (1985) to 4.93¢ (1997).[74] Revenues of Mississippi Power have increased over 26% during the same period.[75] Further, the performance indicators have sustained a high level in regard to price, customer satisfaction and reliability.[76]

Even taking into consideration the growth of Mississippi Power, the results establish that incentives can produce a highly reliable product and service for a fair and reasonable price: thereby enhancing the economic growth and cost allocation reductions in favor of the entire customer base.

In summary, the earned rate of return is compared to the adjusted cost of capital of the utility in calculating the revenue requirement. The width of the range of no change (deadband) above and below the variable

72. MISS. CODE ANN. §77-3-2 (1972) and §77-3-37 (1997).

73. *Id.*

74. Mississippi Power Company, FERC Form 1 (1985, 1997) (See Table A).

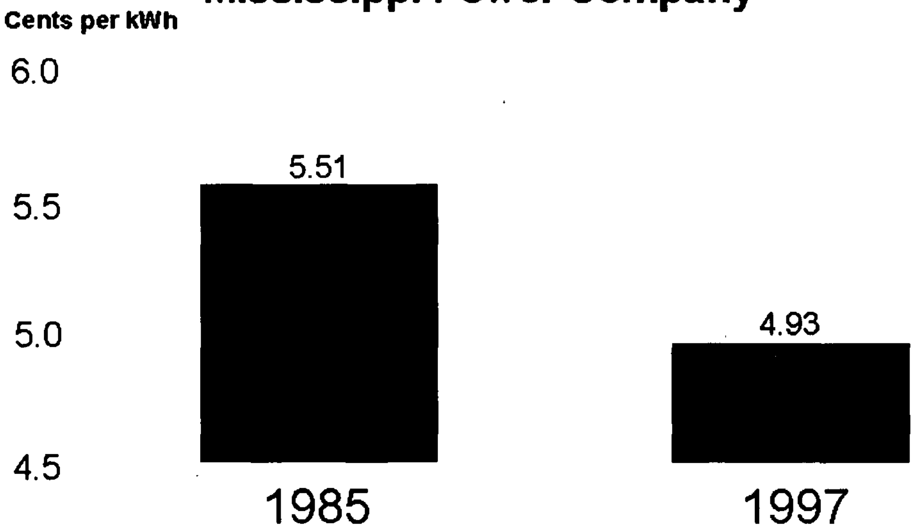
75. *Id.*

76. PEP Evaluations filed semi-annually with the Mississippi Public Service Commission, Docket No. 93-UA-0302.

benchmark (adjusted cost of capital) will be a direct factor of the frequency of rate changes and rate stability. The benefits received from the incentives to the industry and the stability of rates and service for the customer arise from the convergence of reliability and a far less intrusive regulatory hand.

Average Retail Cents Per kWh

Mississippi Power Company



Data from FERC Form 1

Retail Revenues
Mississippi Power Company

1985	1997	% Change
$329,140,433.13	$417,241,698.11	26.77%

III. THE NATURAL GAS INDUSTRY

When the Commission issued Order No. 636[77] many in this industry saw incentive rates as almost a necessary response to the new straight/fixed variable (SFV) rate design. The Commission itself supported the utilization of incentive rates with its concomitant issuance of its Policy Statement on Incentive Regulation.[78] With guaranteed fixed cost recovery under SFV, incentive ratemaking provided a vehicle which would facilitate the control of costs and maximization of efficiency on these systems. Economic pressures of the last few years, however, intervened and brought about most of the benefits experts thought would come through incentive ratemaking. For example, pipelines have significantly reduced their costs. The extent of this cost-cutting was aptly described by James Rubright of Southern Natural Gas Company at the Commission's January 30, 1998 Public Conference on Financial Conditions. He testified:

> [T]he reason pipelines are not jumping on performance and incentive rates is just that the real opportunity in them is gone . . . . Incentive rates work great if you can reduce costs. Ten years ago, Southern Natural had 1,700 people in the field operating our 10,000 miles of pipelines. Five years ago, we had over 700. Today we have 400—400 people operating 10,000 miles of pipelines. If I keep reducing staff at the same rate, in ten years I'm going to operate the pipeline on minus 1,300 people.[79]

The Commission itself is aware that its Policy Statement on Incentive Rates has not been embraced by the natural gas industry. In fact, to determine why there had not been any incentive proposals under the policy established in Docket No. PL92-1-000, the Commission opened another proceeding soliciting comments.[80]

An attraction of incentive rates rests on regulators using them as a benchmark for comparing the cost levels of one company with the cost levels of another company, and rewarding the higher achieving company accordingly. For this to work, cost saving potential must exist. The problem arises when expenses have already been restricted as far as they can reasonably be without jeopardizing either safety or service.

At this point the question becomes: where else can we develop incentives that will spur this industry to act more competitively? As the Com-

77. 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*, F.E.R.C. STATS. & REGS. ¶ 30,939 (1992); *order on reh'g*, Order No. 636-A, F.E.R.C. STATS. & REGS. ¶ 30,950 (1992); *order on reh'g*, Order No. 636-B, 61 F.E.R.C. ¶ 61,272 (1992); *aff'd in part, rev'd in part*, United Distrib. Cos. v. FERC, 88 F.3d 1105 (D.C. Cir. 1996), *cert. denied*, 117 S. Ct. 1723 (1997); order *on remand*, Order No. 636-C, 78 F.E.R.C. ¶ 61,186 (1997).

78. *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Policy Statement on Incentive Regulation*, 61 F.E.R.C. STATS. & REGS. ¶ 61,168 (1992).

79. *Conference on the Financial Outlook of the Natural Gas Pipeline Industry Before the Commissioners*, F..E.R.C. Docket No. PL98-2-000, transcript at 223-224 (Jan. 30, 1998) [hereinafter *Financial Conditions Conference*].

80. *Alternatives to Traditional Cost-of-Service Ratemaking For Natural Gas Pipelines*, 70 F.E.R.C. ¶ 61,139, at 61,395 (1995).

mission itself has said, "the incentive rates policy is still emerging."[81] I think we can find the incentives we are looking for in a more flexible approach to the issues of return on equity, certification, negotiated terms and conditions, and capacity release. More flexibility in these areas will enable this industry to respond to the stifling disconnect between FERC regulated prices and market-driven values.

A. *Return on Equity*

The fundamental rationale for determining an appropriate return on equity is that this mechanism rewards a regulated company for the business and financial risks it faces. In the seminal case on this issue the Supreme Court held "[t]hat return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[82]

The current Commission practice of determining the appropriate rate of return on equity utilizes a two-stage Discounted Cash Flow (DCF) methodology.[83] The two stages, one reflecting short-term growth estimates and one reflecting long-term growth estimates, are equally weighted and utilized in determining a range of reasonable returns. Within this range the highest, middle, and lowest point are identified. The presumption, though, is that most natural gas pipelines face risks that are within the broad middle of the zone of reasonableness.[84] Under the Commission's current DCF methodology, this results in an applicable return on equity of approximately 10.88 percent for all but the riskiest or the safest pipelines in the industry.

A return on equity of 10.88 percent might not, in most cases, provide companies with the ability to adequately attract capital. In fact, at the Financial Conditions Conference many pipeline representatives indicated that the rates of return generated by the Commission's two-step DCF methodology were significantly below the levels needed to stimulate the investment that will be necessary to meet the anticipated gas needs for the future.[85] As Keith Bailey, CEO of the Williams Companies stated, "A 10.88 percent expected return will simply not stimulate new investment and accommodate thirty Tcf of gas demand, this segment of the industry conservatively needs to spend twenty-five billion dollars between now and the year 2010."[86]

Mr. Bailey went on to underscore the impact of a 10.88 return on eq-

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81. *Alternatives to Traditional Cost-of-Service Ratemaking For Natural Gas Pipelines*, 74 F.E.R.C. ¶ 61,076, at 61,238 (1996). As part of this order the Commission revised its incentive rate criteria to remove the quantification of benefits requirement and the cost-of-service cap. *Id.* at 61,237.

82. FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

83. *Transcontinental Gas Pipeline Corp.*, 80 F.E.R.C. ¶ 61,157, at 61,669 (1997).

84. *Transcontinental Gas Pipeline Corp.*, 80 F.E.R.C. ¶ 61,157, at 61,674 (1997); *Williams Natural Gas Co.*, 80 F.E.R.C. ¶ 61,158, at 61,687 (1997).

85. Projections for future U.S. gas demand are that demand will increase to 30 Tcf by the year 2010. *Financial Conditions Conference*, transcript at 9.

86. *Financial Conditions Conference*, transcript at 12.

uity when he argued, "If we are truly expected to live in a 10.88 percent world, Williams, for one, will not make any more expansion investments, and we will cease all but the most minimal project development activities."[87]

For me to hear that pipelines see the current DCF-derived rate of return as failing to attract sufficient capital calls into question whether we are meeting our mandate to set rates at a level that attracts and rewards capital to the industry.... Accordingly, I suggest that the Commission use the potential of an increase above the current DCF-derived return as an incentive to spur the attraction of capital. As I explored at the Financial Conditions Conference, a pipeline that would be willing to forgo stranded cost collection for a new project and accept incremental pricing, could be rewarded with a rate of return higher than the DCF-derived return.[88]

If the Commission would use a higher rate of return as an incentive, it would give the industry the incentive to respond to the anticipated, impending growth in demand, and, at the same time would protect ratepayers from the impact of stranded costs, while giving shippers alternatives.

The example of a higher rate of return in conjunction with new, incrementally priced construction illustrates how incentive rates can be used to encourage development in this industry. More important, once derived, the rate of return should be used with some flexibility as a tool that would mimic the pressures and influences that a free market would exert.

B. *A Definable Certificate Policy*

As noted, current estimates are that natural gas demand will surge to an unprecedented level of thirty Tcf by the year 2010. Flexible application of the return-on-equity policy may provide the incentives needed to meet that demand. As was also noted at the Financial Conditions Conference, the return on equity policy must be addressed now as pipeline projects have a substantial lead-time and construction period before the systems are operational.[89] The substantial lead-time that is necessary for new construction leads me to my second point: that a definable certificate policy will be a great incentive for ensuring that demand is met.

At this time, numerous certificate projects are pending before the Commission. In sum, those projects represent more than eleven billion dollars in potential investment and would provide thirty eight Bcf a day of new interstate capacity.[90] The Commission's certification policy has, until recently, been that certification is authorized upon a showing of market need, and that need is presumed if the applicant provides evidence that a

87. *Id.* at 13.

88. *Id.* at 67, 68.

89. *Financial Conditions Conference*, transcript at 15. Testimony of Keith Bailey, "Pipeline projects, even relatively simple ones, have long lead times. Major projects can and often do take up to seven years from start to finish."

90. *Financial Conditions Conference*, transcript at 19.

significant amount of capacity is subject to contract.[91]

However, in the recent *Granite State* proceeding,[92] the Commission failed to authorize a project that not only met, but exceeded Commission precedent and policy on the market need standard. The majority's decision to forestall authorization on the basis of the alleged necessity for further evidentiary hearings hearkens back to the Commission's previous use of comparative hearings for determining certificate projects.

This approach is contrary to our stated policy and creates a negative incentive for companies considering a certificate application. The best incentive the Commission can put forward in the certificate arena is a definable policy that supports the current market need standard. As I argued in my dissent in *Texas Eastern*:

> [T]he decision to require Commission inquiry into contracts beyond their compliance with the Commission's regulations is a step backward to the onerous burdens of a more invasive regulatory scheme.... This would be heavy-handed regulation at its clearest, chilling the ability of parties to contract for their needs while assured that they are free from regulatory second guessing.[93]

The greatest incentive that the Commission can provide with relation to certificates is that business assessments of need, and contracts on the basis of such, will be respected. If such assessments prove to be incorrect, market forces will determine which projects go forward and which do not. I am concerned that the Commission's recent actions in these cases will stifle, rather than encourage, actions in the certificate arena. Instead, this Commission should remain faithful to its articulated policy of confining itself to the four corners of a contract and accepting applicable contracts as evidence of market need.

C. *Negotiated Terms and Conditions*

This Commission can provide a great deal of incentives to this industry by permitting the negotiation of terms and conditions. By permitting parties to tailor terms and conditions to the needs of their specific situations, the Commission can provide an incentive which will simulate innovation and creativity in pipeline services both for the provider and for the customer. As this proposal addresses many issues, I cannot speculate on the breadth of terms and conditions we may see negotiated, if permitted. Instead, I argue that use of this tool should not be foreclosed because its utilization will enable the industry to respond to competitive pressures in a creative manner and provide customers with more useful choices.

D. *Capacity Release*

Another area that is ripe for new incentives is the secondary market

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91. *El Paso Natural Gas Storage Co.*, 65 F.E.R.C. ¶ 61,276, at 62,270 (1993); *Steuben Gas Storage Co.*, 72 F.E.R.C. ¶ 61,102 , at 61,536 (1995).

92. *Granite State Gas Transmission Co.*, 82 F.E.R.C. ¶ 61,232 (1998).

93. *Texas Eastern Transmission Corp.*, 82 F.E.R.C. ¶ 61,118, at 61,440 (1998).

for short-term capacity—specifically, capacity release. The first transaction involving capacity release in the gas pipeline market occurred almost five years ago. After recording annual increases, the industry is beginning to see declining levels of capacity release volumes.[94] By removing the artificial barriers that the FERC imposed on capacity release, the Commission can give all parties a greater incentive to utilize released capacity. Specifically, we could remove price caps from released capacity. Without the artificial constraints caused by price caps, released capacity will be placed on a better footing to compete with other short-term services, such as pipeline interruptible, short-term firm and bundled sales in the grey market.[95]

By treating released capacity in a manner similar to other short-term services, which are not subject to limitations such as the price cap, the Commission will be able to increase the ability of the industry to view all short-term services as competitive options and this, in turn, will enhance the overall competitive nature of the industry.

IV. CONCLUSION

William Faulkner said, "Don't bother just to be better than your contemporaries or predecessors. Try to be better than yourself." There are no words more fitting for the natural gas and electric utility industries today. Parallels to yesteryear or even yesterday will not suffice in the new competitive utility arena. Any utility satisfied with standing still should not complain when others in the industry provide less expensive and more reliable energy, therefore passing them by.

The marketplace has manifested that regulators provide inventive approaches for the natural gas and electric utility industries. However, no worthwhile advance will be made without significant heartache, controversy, and debate. For some readers, I am certain we have provided all three.

94. *Release Market Sees Lower Volumes in 1997,* GAS DAILY, Mar. 13, 1998 (Eastern Edition):
More than 65,000 awarded deals have been posted on the various proprietary pipeline electronic bulletin boards since 1994. Over 12,000 deals were exchanged in 1994, about 16,000 in 1995 and 18,400 in 1996. Only slightly fewer transactions occurred in 1997 - about 18,260 - than in 1996. And in 1994, about 3 trillion cf of firm capacity was released by shippers. About 4 trillion cf was released the following year. . . . In 1997, the volume of released capacity held has returned to those seen in 1995, falling to about 4.5 trillion cf.

95. The phrase "grey market," to those at the FERC and in the industry means transactions that tacitly bundle natural gas with transportation service.