Economic Regulation under Distributed Ownership: The Case of Electric Power Transmission[1]

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Executive Summary

This paper argues that the electric power industry must move toward a model in which transmission service is viewed as a commercial activity, a business. The current models of integrated utilities and quasi-public, not-for-profit Independent System Operators have led to a trend of under-investment. The current model of transmission operation divorces ownership and control and, as a not-for-profit corporation, lacks accountability to current and future investors, and is not focused on innovation to meet customers' needs. If such a model becomes the model of choice for the RTOs required under FERC Order 2000, current trends of anemic investment in transmission will continue.

The problem of inadequate investment in transmission arises primarily because of the uncertainties underlying the diverse factors that determine revenues for capital recovery of investments in transmission. This lack of clarity, in turn, results primarily from two sources: (i) multiple stakeholders and multiple regulators with no clear governance structures to drive key decisions; and (ii) the complexity and interdependence of the power grid itself. This latter characteristic also contributes to the public good character of reliability investments, making it difficult for distributed owners to come to grips with who should pay for reliability.

Current models of regulation and operation of transmission service fail on a number of dimensions that are central to any commercial undertaking. These include an understanding of the rights, roles and responsibilities of asset owners, which are clouded by arcane pricing methodologies (including contract path methods), and by a lack of clear authority and responsibility to measure and guarantee performance to the customers of the undertaking. These issues are further complicated by the problem of assuring fair treatment to current asset owners, and their customers who have financed the current grid to date, while providing incentives to investors for much needed additional investments. This is a very large and thorny problem, which FERC and other industry participants have been struggling to sort out as part of the restructuring debate. This paper focuses primarily on one aspect of this debate, the decision rights and governance of the RTOs now being designed. I consider several varieties of the RTO, ranging from the pure

[1] The author gratefully acknowledges helpful comments on an earlier draft by Camden Collins, Michael Crew, Marija Ilic and Stephen Peck. The author alone bears responsibility for remaining errors and opinions. This paper was written as part of an overall assessment of the August 14, 2003 blackout. Companion papers to this from other authors can be seen at http://www.charlesriverresearchcorp.com.
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Independent System Operator, to the modified independent transmission entity that leases lines, to the fully divested transmission company. The first type manages the system others build and the last two invest in facilities.

In thinking about the structure of the RTOs, I argue that the first order of business is to clarify current regulatory goals to promote transmission as a business. This includes designing regulatory incentives for grid performance, to reward success and penalize failure. This leads to a conclusion that, while cost of service regulation may work for current facilities, ultimately, the industry must move to performance-based rates that recognize the central role of investments in reliability as well as congestion mitigation. I then consider the merits of various RTO structures in being able to function as a commercial, capital-intensive entity to deliver transmission service efficiently under a performance-based regulatory environment. I argue that the currently popular system operator model cannot endure in the long run, as it is not accountable to either capital markets or customers, i.e., it does not face the consequences of either poor investment choices or poor control and operating performance. In addition, the decentralized planning process in the current model encourages free riders, especially where investments in reliability are concerned.

In contrast, the modified independent transmission entity and the fully divested transmission company have increased incentives to invest wisely. Their investment decisions directly affect their "bottom line." In turn, these entities have the potential to attract investment. The profit motive driving investment ensures that investors will seize opportunities before others take advantage of the possibility to reap potential rewards. The result is that the desired competition between generation, including distributed generation, and transmission can be better achieved.

The paper lays out four principles to guide the restructuring of governance and regulation of transmission providers. Transmission entities should face incentives that will encourage: (1) measurement and accountability for performance, (2) a focus on customers, (3) the integration of engineering and economics in operations and planning, and (4) a governance structure that will be capable of making decisions in a timely manner concerning investment, grid management and customer needs. Regulators should actively promote the evolution toward for-profit transmission companies with performance-based rates, and they should accommodate regulation that reinforces a focus on measurement and performance accountability. If the current model continues, with the compendium of misaligned rules, requirements and policies of the new order contributing to a lack of accountability for grid performance, then restructuring could well be a net drag on our economy, and situations such as the lack of communication and monitoring of the grid that led to the August 14th blackout may well persist in the future.

Introduction

The theory of economic regulation has traditionally focused on a single regulator regulating a single company. Anyone familiar with the case of electric power transmission will note that the reality in this sector is considerably more complex. In the U.S., there are multiple regulators and multiple, interdependent providers. These providers include both current and potential transmission asset owners and investors, as well as the organizations (the Independent System Operators or ISOs) with responsibilities for real-time operation of the grid. The regulators include state utility commissions responsible for price and profit regulation of licensed distribution companies; the Federal Energy Regulatory Commission (FERC), with responsibilities for regulating those transactions affecting interstate commerce in electric power; and North American Electric Reliability Council (NERC), with responsibilities for monitoring reliability and setting technical standards in cooperation with industry. Some of the providers are purely engaged in transmission, and some are divisions of larger companies with generation, trading and distribution businesses. These organizations are not separate entities that can be thought of, either economically or physically, as independent. Rather, organizations involved in providing transmission service are tied together by the laws of physics, including the requirement that instantaneous balance be maintained between supply and demand across the interconnected grid. A regulatory regime that neglects these interdependencies will, at best, generate chaotic conditions and a loss of credibility and legitimacy. At worst, organizations facing confused incentives will respond to these independently, leading to huge economic losses from unreliable transmission service, such as those seen in the August, 2003 blackout.

I will argue that a new approach to the regulation of transmission services and related investments is required, an approach that recognizes the interdependencies linking the various stakeholders engaged in transmission operations in the U.S. While it may take some time to develop a workable general theory, and even more time to place this theory into practice, I think that we can do better than simply waiting for the next blackout to tell us where the weak links in the system are. To be specific, I will analyze here a few of the central problems in today's debate about Regional Transmission Organizations (RTOs), and the related discussion of Independent Transmission Providers and Independent System Operators (ISOs), the current centerpiece of FERC's proposed regulations of transmission providers.[3] In the process, I want to highlight what both intuition and economic theory suggest must be in place to achieve good results, contrasting these requirements with the process and the assumptions that seem to be guiding the debate today. The most important elements I underline as needed changes in our approach to transmission regulation are: (i) a more realistic approach to account for decision rights under distributed ownership of the grid, and (ii) a move toward a more accountable organizational form that can credibly deliver on the FERC Order 2000 requirement to

[3] Various designations are used to denote the emerging organizations that are intended to have real-time control of dispatch, transmission assets and system balancing functions. These designations vary according to whether the organization is a for-profit entity, whether it owns all transmission assets or simply has operational control of them, and on other dimensions. I focus here on the RTO. The Independent Transmission Provider (ITP) designation has usually been thought of as a territory specific spin-off, contrasting with the integration across transmission owners of the RTO framework. The ISO is the organization having responsibility for the real-time controller of system operations. Naturally, an RTO or an ITP would have an ISO (or some organization that functions as an ISO) as part of its organizational structure. While I focus on the RTO here, I will therefore also discuss the ISO and its functions as well.

plan and manage grid operations and expansion and its promise of a viable transmission business.

While we have learned a great deal from our experiences of the past decade, in the US and abroad, we seem to have arrived at a stalemate in various regions of the U.S. in respect to fair and efficient procedures for assuring further progress in creating a sustainable power grid for the future. At present, we find ourselves without a coherent vision for the future of the grid, and the costs of this lack of a shared national vision are immense. Daily, hundreds of well-intentioned people are churning out arguments and counter-arguments as to appropriate directions for movement, without discernible progress. RTOs are being set up with little understanding of the principles that will ultimately govern their basic product, reliable transmission service, as a business. Risk analysis of the power grid is not being accomplished in a holistic fashion, but piecemeal and in response to uniform technology standards that address neither efficiency nor flexibility, let alone responding to market-driven needs for transmission service. Instead of addressing these issues as central aspects of the economics and engineering design of the grid, the current environment seems much more intent on finding simple explanations that explain on the surface events like the blackout of August 14th, but do not recognize the problems of incentives, governance and regulation that underlie the current malaise about the future of the U.S. grid. In my view, this malaise is the result of the lack of a coherent vision concerning regulation and workable governance for the grid. I argue that constructing a coherent vision will require fundamental changes in the way in which decision rights and governance of the grid are understood. Most importantly, we need to recognize the sheer complexity of the restructuring exercise facing the country, and we need to bring a certain humility to the debate, a willingness to experiment with alternative forms of governance going forward, and a proper concern about the embedded rights and responsibilities of current participants as we consider changes from the status quo. The ideas expressed here, and those of others involved in this project[4], are intended to promote some new avenues of exploration and discussion on these important themes.

The remainder of this paper proceeds as follows. In the next section, I mention some desiderata for economic regulation, with specific reference to transmission service provision. I then focus on two major issues confronting the design of RTOs: the issue of governance and decision rights for the resulting RTO (can it make appropriate decisions about investments and operations?), and the regulation of performance of the RTO (can the RTO be held accountable for its ultimate performance in cost and reliability?). In my concluding section, I put forward a few principles that represent some modest initial steps towards improving our understanding of how to set up effective economic regulation for an interdependent system of economic agents, such as those engaged in providing transmission service in the U.S.

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[4] I refer here to the companion papers by my colleagues Stephen Fairfax, Michael Golay, Leonard Hyman and Marija Ilic, each addressing this same problem nexus from different perspectives.

1. Some Desirable Characteristics of Economic Regulation of Transmission Service

In a companion paper to this[5] I summarized a number of arguments stemming from economists, regulators and the investment community to the effect that the current environment is not conducive to attracting investments in support of transmission service. These arguments can be summarized as reflecting two basic problems with the regulation of transmission service: (i) complexity and ambiguity in the multi-tiered regulatory process discourages investment; and (ii) there is a perceived lack of regulatory commitment to principles that will assure reasonable returns to prudent investors over the multi-year time frame required for capital recovery for transmission investments. Rather than revisit these arguments, I discuss here the conditions that I believe will encourage efficient investment, i.e. investment that creates value.

Regulatory and financial economists, both normative and behavioral, generally agree that the following characteristics are important in evaluating whether or not to invest in any capital project.

First, there must be an opportunity to earn predictable and adequate profits from investments, where adequacy includes a return based on the risk associated with the investment returns, and is defined on the basis of competing opportunities elsewhere. Uncertainty and ambiguity, especially if it stems from the regulator rather than from demand and supply conditions, weighs heavily on investor behavior. Note here that it is not "risk" that is the problem, where the risk can be properly identified and quantified as a stable extrapolation of historical data. It is the sheer unpredictability of the distribution of profit outcomes that undermines investment or, equivalently, that drives up the risk premium for such investment so high that the project becomes too expensive to finance.

Second, and as a key corollary to the first characteristic, and particular to regulated industries, the level of allowed revenues to a regulated asset must be clearly linked to the principle of capital recovery.[6] Sever this link, and there will be problems attracting investment. Make this link incomprehensibly complex, with multiple regulators playing a role in the determination of allowed revenues on the same assets, and there will be problems. Make allowed revenues a political outcome and there will be problems, especially if the political trigger shifts with the wind. Finally, obscuring or delaying capital recovery will make investment more costly or discourage it altogether.

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[5] Paul R. Kleindorfer, "Perspectives on the Economic Regulation of Electric Power Transmission", mimeo, The Wharton Center for Risk Management and Decision Processes, November, 2003. See also Leonard S. Hyman, "How and Why We Got Here from There", mimeo, Private Sector Advisors, Inc., November, 2003.

[6] See Kleindorfer, ibid., for a discussion of some elements of price structure that are important to keep in mind in assuring simple, yet effective pricing rules for transmission. I argue that because of the fixed cost nature of the transmission grid, most of these costs should not be collected in congestion-based usage fees, but rather through access fees to the network itself, thus charging generators and loads a fixed fee for access to the network, which would pay most of the fixed costs of the network and would, moreover, make the revenues attributable to certain assets much clearer than they are under a pure usage-based system.

The informed reader will have no difficulty seeing that these principles are not satisfied for many if not most transmission projects. The primary reason is the interdependency and complexity that link participants and regulators in the transmission sector. Rather than recognizing this interdependency, multiple regulators with conflicting objectives set various policies that ultimately determine both allowed revenues and costs. Existing and FERC-proposed pricing regimes are anything but transparent, making the problem of profit predictability and capital recovery immensely uncertain. Transmission is not a business in today's environment. The combination of existing so-called "contract-path" transmission pricing methods and current proposals for allocation of revenues to cover congestion costs present some participants with windfall gains and others with added responsibilities and no revenues to cover these. Thus, rather than having a clear business mandate to develop and deliver high-quality service, transmission in this environment is a mixed bag somewhere between a lottery for potential investors and an auction at gunpoint for existing transmission asset owners. Regulation in the past was viewed as a stabilizing force, providing increased certainty for both investors and customers. It was, in other words, a handmaiden to supporting the utility's business rather than a hindrance to its operation. Similarly, "base load" customers in the traditional world were the backbone of the business, and they benefited from predictability and transparency of the rate-setting process. The state of regulation in the present world of unbundled electric power supply has clouded this issue considerably, especially in the transmission sector, where overlapping regulatory jurisdictions, together with unsettled cost and revenue allocation issues, have led to a "defend your turf" mentality that is neither good for the business of transmission nor for the customers of this business. As a result, it is not surprising that investment in transmission has been anemic for the past decade, and may be putting the entire grid at risk of further catastrophic failures unless the investment climate improves.

What are the key leverage points that will assist in moving towards a more realistic model of regulation and an improved investment climate for efficient investments in transmission? As many researchers and practitioners have argued over the years[7], the central ingredient is to craft a coherent vision that will promote efficient investment in the grid and accountability for performance by the grid operator. The design should also provide appropriate incentives for technological innovation and for a customer-focused transmission service. The FERC's Standard Market Design Notice of Proposed Rulemaking (SMD NOPR)[8] was an attempt to do just that. The SMD NOPR contains many important elements of the emerging framework that could form the basis of such a consistent vision going forward. These elements include bilateral schedules, a coordinated spot market, and security-constrained, economic dispatch at nodal prices. Where the SMD NOPR falls short is in two areas: (i) in recognizing the problems of effective governance and decision rights for RTOs with distributed ownership of assets;

[7] For recent cogent summaries of these points see Paul R. Kleindorfer, *ibid*.; William W. Hogan, "Transmission Market Design", J. F. Kennedy School of Government, Harvard University, April 4, 2003; Paul L. Joskow, "The Difficult Transition to Competitive Electricity Markets in the U.S.", MIT, April 4, 2003. Sally Hunt, *Making Competition Work in Electricity*, Wiley, New York, 2002.

[8] Federal Energy Regulatory Commission, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, Washington, DC, July 31, 2002.

and (ii) in creating the conditions for a value-added orientation by the RTO to the business of providing transmission service. I consider these matters in the next two sections.

2. Decision Rights in a Distributed Ownership Model of Transmission Service

Fix attention on a single region, with an RTO/ISO having responsibility for maintaining balance in real-time, and with a number of generators, distribution companies and possibly other Load Serving Entities (LSEs), providing electrical service to a set of final customers. The recognized economic benchmark for efficient provision of electric power in such a setting is the solution to the following problem:

Maximize Welfare = Profits of Service Providers + Consumer Surplus of Consumers

Subject to: (1) Balancing Equations Relating Injections and Extractions
(2) Security Constraints
(3) Ancillary Generation Requirements for Voltage and Frequency Control

In this formulation, profits include those of generators, transmission providers and LSEs serving final customers, and such profits include the cost of providing returns to capital providers. The balancing equations ensure that enough real power is generated to balance extractions and line losses. These balance equations contain both flows into and out of the region/control area of interest as well as flows internal to this region. Security constraints are constraints on the economic dispatch of generators and transmission to assure that the system can still operate under various failure scenarios (e.g., an "n-1" contingency constraint would require operations that would allow the system to maintain balance if any single resource of "n", e.g. a single line, were to fail). Ancillary generation requirements include reactive power and voltage support to ensure the proper operation of the system,[9] which comes at a cost to the RTO/ISO providing such support. Implicit in the above problem are also standards for safe interconnection of loads and generators to the system, of limits on frequency of AC power, and many other technical standards that define the "commodity" electric power in a manner that allows this intermediate good to be effectively utilized by households and industry.

As it stands, the above design framework is not of much use except as a benchmark, and it is not a very realistic benchmark at that. First, decisions affecting this welfare function are taken at different times (investment in the long term, maintenance in the medium term, commitment in the short term, and operations in real time), and all of these time frames are subject to different forms of uncertainty. Thus, the actual benchmark must be

[9] While this is the traditional terminology, the descriptor "ancillary" may be a large part of the current problems in over-simplifying transmission interdependencies. Voltage and frequency support are anything but "ancillary"; they are essential and were proven to be so on 8/14, as noted in Stephen Fairfax, "What Happened?" mimeo, MTechnology, Inc., November, 2003. Indeed, the failure to price properly or set design principles for the acquisition of such services, while still confronting regional ISOs and local transmission owners with the necessity of providing open access for wheeling and other non-local services, is a major problem with the current structure and trends in transmission.

an average or expected welfare measure over scenarios describing this uncertainty.[10] Second, we need to append the requirement that service providers can expect to at least break even, i.e. have non-negative profits over the long run. Of course, under traditional regulation, the way to assure this has been to make whole ex post any producer that makes negative profits, but this "solution" is generally recognized as leading to troubled waters since it will encourage such a producer to be internally inefficient and to make very risky choices using "house money". Third, and important for my argument here, is the implicit assumption in the above model that "someone", an organization or an institution, has also the necessary information and motivation to actually carry out the above welfare-maximizing design framework. To take care of these problems, economists rely on the basic assumption of self-interest seeking behavior of companies and consumers. This assumption states that economic agents, left to their own devices, will not undertake activities that are not in their interest. This assumption is often used to unbundle one element of a multi-sector problem from another. The idea is that if all but one element in a system can be assumed, because of workable competition and regulation, to be functioning properly, then one can focus separately on the remaining element in designing an efficient approach for the entire system. In transmission, this works as follows. Let us suppose a competitive generation market and sufficiently focused regulatory incentives to motivate efficiency in distribution and retail services. Then these parts of the overall electric power value chain can be assumed to provide efficient, i.e. welfare-maximizing levels of service at sustainable levels of profit.[11] We only need then to focus on transmission as a separate, unbundled activity. This is effectively what the FERC and others have tried to do at a regulatory level in FERC Order No. 2000, and the regimes on which it was modeled. Especially under the FERC's Standard Market Design, the thought became that if one declares that transmission provision is "independent" from generation and distribution, it will be so, and it can be then regulated under the old command and control models of regulation.

The problem with the FERC's new approach is that the presumed independence underlying it is not in accord with either the reality of ownership in today's grid or with economics or the laws of physics. Specifically, the status quo in the U.S. does not support either the separability of the constraints connecting, or the separability of aggregate welfare contributions arising from, generation, transmission and distribution. The most glaring non-separability arises because many power companies, as descendants of their vertically integrated ancestors, control elements of all three elements of the electricity value chain. Thus, their decisions concerning transmission investments are interdependent with decisions regarding their generation base and their native load.[12] A

[10] For a discussion of risks in design and operation of transmission systems, see Michael Golay, "Risks and Electricity Deregulation", mimeo, Charles River Research Corporation, Cambridge, January, 2004.

[11] As I note in more detail below, this unbundling approach also implicitly assumes that the constraints applicable to generation, transmission and distribution are separable and that the contributions of these three aspects of electric power provision make separable contributions to aggregate welfare in the sector. Without some changes in the organization of transmission provision, there will be problems with both of these assumptions, as my discussion below points out.

[12] I will not enter into a discussion of the additional tactic sometimes proposed, the California solution, of mandating the divestiture of generation as a "cure" for some of these non-separabilities. While this may have some benefits in achieving separation between generation, transmission and distribution, it also

further interdependency arises in the obvious tradeoff between generation being used for real power that can obtain market-based rates and for reactive power, the latter in support of transmission that generally operates under cost-based regulation. A further problem arises because we have dealt in the above formulation of the welfare problem with only one RTO/ISO, when in fact there are numerous examples of decisions in one RTO/ISO region affecting another, some of these involving companies with operations and decision externalities across two or more ISOs.[13] Finally, it should be noted that transmission and generation are themselves competitive alternatives, as the recent growth in distributed generation in response to grid reliability problems has demonstrated.[14]

This main point of this discussion is that transmission provision in today's interconnected grid entails multiple actors, with differing economic objectives, and with interdependent constraints and decisions that make it difficult to conceive of a scheme that will unbundle this sector into manageable chunks that can be run as efficient business activities and regulated where regulation might help. These types of problems in economics are captured under "externality problems"[15]; in plain English, though, one might refer to them simply as messy problems. They just do not separate out into nearly independent entities, for which aggregate performance is the sum of the performance across individual, independent units. If they did, decentralization through markets and some focused regulation could achieve near-efficient results. In contexts like electric power, however, the situation is different and one must be very careful of making implicit assumptions about how well such decentralization approaches work.

Lest I leave the reader with a sense that nothing whatsoever can be done, let me now turn to a few of the working elements of the current FERC approach to dealing with the massive externalities that exist in the electricity sector. First, even the most market-based economist recognizes that once the system approaches real time, markets become

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significantly increases the risks of exposure by the resulting generation-less companies to generation cost volatility.

[13] For a detailed discussion of the issues of interdependency in electric power, and their consequences for engineering and economic design, see Marija D. Ilic, "Engineering Needs For Enhancing Performance of the U.S. Electric Power Grid: Regulated Industry, Performance Measures, Methods and R&D Needs" and "Regulatory/Market and Engineering Needs for Enhancing Performance of the Electric Power Grid: Alternative Architectures and Methods for Their Implementation", mimeo, Department of Electrical Engineering, Carnegie-Mellon University, Pittsburgh, January, 2004.

[14] For a discussion of this issue, see Peter Huber and Mark Mills, *Critical Power*, Digital Power Group, Washington, DC, August, 2003. The key is that transmission is not the only solution to grid reliability issues. There should be a transparent and dynamic interplay between transmission and generation investments that allows individual participants, and regulators, in the power market to make informed choices about the relative mix of transmission, generation and demand-side investments that should be made to promote system-wide efficiency.

[15] In economics, externalities are generally classified as either "pecuniary" or "technological", where the former means that the actions of one agent affect the payoffs of another agent, while the latter means that the actions of one agent affect the nature of the feasible set available to another. Both types of externality are present in electric power. Externalities might further be classified as "easy" or "hard", where easy externalities are characterized by additive or linear interactions, while hard externalities embody non-linear interactions. The difference between these is that linear interactions can often be approached through pricing mechanisms, susceptible to decentralized implementation, whereas non-linear interactions present more difficult hurdles in attempting to decentralize the solution to a problem.

ineffective in controlling the electric power system. In the language of Nobel Laureate Ronald Coase and his intellectual descendents Oliver Williamson and Paul Joskow, the organizational boundaries determining the governance of real-time operations in electric power require a hierarchy rather than a market to make efficient choices. This recognition has given rise to a resolution of at least some of the problems of dealing with the interconnectedness of the overall power system. As the FERC has carefully crafted, this requirement of a hierarchy gives rise to the four minimum characteristics of an RTO/ISO: independence, scope and regional configuration (to cover electrically significant interactions), operational authority, and responsibility for short-term reliability. Moreover, regulatory economists have characterized several versions of the problem that must be solved by the RTO in the short run and in real time. These take two general forms, the centralized and decentralized approach.[16]

Under the decentralized approach, participants in the market are able to contract bilaterally and schedule (in a day-ahead energy market) their contracts with the RTO, based typically on an inter-zonal feasibility test. The RTO is then responsible for managing and resolving real-time operations. This is the approach used in Texas, for example. In the centralized approach, implemented in the PJM Interchange, New York and New England, bilateral trades are purely financial in nature, based on nodal prices, and do not get scheduling priority. Bilateral trades on the day are charged the nodal price differences between the points of trade. In this centralized market, the RTO/ISO solves in real time what William Hogan has called the "bid-based, security-constrained, economic dispatch problem".[17] To be specific in what follows, I will focus only on the centralized market design in what follows, though a parallel discussion for the decentralized market design would lead to similar conclusions.

If an RTO has no electrically significant interactions with any other RTO, then whatever the topography of the grid and the decisions by customers on their demands and by generators on their technology and readiness, solving the problem of security-constrained, economic dispatch is a necessary condition for efficiency.[18] Moreover, solutions to the economic dispatch problem are feasible and, when coupled with nodal pricing and associated information support services, can provide valuable information to

[16] For a good recent summary and discussion of the literature on the economics of various market design and settlement systems, see Rajnish Kamat and Shmuel S. Oren, "Two-Settlement Systems for Electricity Markets under Network Uncertainty and Market Power", Working Paper, IE/OR Department, University of California at Berkeley, April, 2003.

[17] See William W. Hogan, *opus cit. supra,* and William W. Hogan, 1992. "Contract Networks for Electric Power Transmission," *J. of Regulatory Economics,* December, 211-42. For an alternative formulation and approach, see Hung-Po Chao, Stephen C. Peck and Robert Wilson, 2000. "Flow-based Transmission Rights and Congestion Management," *Electricity Journal*, October, 38-58. It is not my purpose here to address or evaluate alternative approaches to the real-time control and congestion management problem facing an ISO. I wish only to point out a general recognition and acceptance of this problem and of its being "solved" by a hierarchy rather than by a market.

[18] Security constraints are included as they are considered essential characteristics of the good, "electric power", provided by the system. But, as noted by Golay, fn 6, *supra*, the nature of appropriate constraints and standards for grid operation and dispatch needs to be revisited in light of the intended consequence of restructuring to move the grid closer to its safe operating limits.

market participants on the value of various transmission services (on specific lines or point-to-point) and of congestion management.

However, solving the problem of economic dispatch through an empowered RTO, and even solving the problem of providing proper price signals on the value of short-term congestion to generators and LSEs, does not obviate the problem of inseparabilities and externalities in electric power provision. These problems are still there, and indeed they act to fundamentally condition the nature and outcome of the real-time problem the RTO solves. Consider a few of the most obvious interactions:

> Investment choices by generators, transmission asset owners and distribution companies will determine the structure of the technologies available for dispatch by the RTO/ISO.
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> Maintenance and other determinants of unit commitment decisions affecting the readiness of generators for dispatch will affect the structure of technologies available for dispatch by the RTO/ISO.
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> Reactive power and voltage support available to the RTO/ISO will be affected by both readiness conditions of generators as well as their competing commitments to the real power market.
>
> The availability and level of information of demand management and real-time pricing contracts and technologies will affect the ability of the RTO/ISO to make use of these in economic dispatch.

These and other decisions may or may not be within the scope of the model for regulation and market design envisaged. If they are not, then they will be made in the interests of those who control the assets in question, and in response to the anticipated profit consequences of their decisions as determined on the day by the RTO/ISO. To put the matter bluntly, these interactions exist and condition the nature of the economic dispatch problem in real time, and they will therefore affect the overall efficiency of the system, whether or not the real time dispatch problem is solved optimally.

To illustrate the policy choices and difficulties inherent in this situation, consider just the first of the above interactions, that involving long-term investments. And to be specific, let us focus just on transmission investments. Suppose, to make our argument simpler, that generation and distribution decisions have all been fixed, and that generators and loads bid their true short-term costs, prices and dispatchable capacity to an isolated ISO, which then solves the resulting economic dispatch problem of finding the best security-constrained units to dispatch to satisfy demands. Let us write the aggregate welfare associated with the solution to this problem at time t, and under scenario s, symbolically as $W(q, L, u, s, t)$, where q is the vector of dispatched quantities from available generating units, L are the capacities of available transmission lines, and u are other required inputs such as ancillary generation for voltage and frequency control. Welfare W is the sum of profits and consumer surpluses across participants in this market.

Suppose one of the participants in this market owns both generation and transmission resources, as well as having native load responsibilities. Then investment and readiness choices by that utility affecting L will depend on their anticipation of payoffs resulting from the interaction of their choices of L and q in the real-time dispatch market. Thus, what to some might look like a nice approach to the problem of interdependencies of choice, by subjecting economic dispatch to the transparent, hierarchical administration of an independent RTO/ISO, actually does nothing to deal with the fundamental underlying interdependencies in the investment and readiness phases of choice by market participants. For example, the PJM model for congestion pricing and security-constrained dispatch is viewed by many as the "model of choice" now, and arguably the short-run functions executed by PJM are at or close to the state-of-the-art. However, this model does nothing to solve the interdependency problems of investment and readiness that fundamentally condition the state of the system that will confront the PJM ISO as it engages in economic dispatch on the day. In this sense, the PJM "model" is fundamentally incomplete, both as a model of providing transmission service over the long run and as a business model for balancing the revenues and costs of such service.

I have focused on transmission decisions in the above discussion, but similar comments apply to other externalities across interdependent participants, regions and time frames affecting choice. What is to be done to confront these difficulties? With a focus on transmission, one might approach the problem in several ways. I briefly consider three options below, in increasing order of the level of centralization of the investment decisions in transmission:

<u>Autarchic RTO</u>: The RTO is structured according to the minimal characteristics and functions specified by FERC Order 2000, leaving the planning and management of transmission system expansion to individual investors and utilities, with joint coordination and needs determination, but with no coercive action possible by the RTO, FERC or state commissions. Under this model, transmission investments, whether in control systems or in line enhancements, would be made only if it is in the interest of some qualified individual or group of participants in the RTO's region of responsibility to do so.

<u>Mutualized RTO</u>: In the mutualized RTO, transmission assets would be leased or sold to the RTO by transmission owners, and these would be valued at the time of lease and "revenue rights" would be granted to leasors based on the value of their leased assets.[19]

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[19] Given the extended discussion in FERC Order 2000 on independence and organizational form, it remains to be determined exactly how active a role such transmission asset owners will be allowed play in the determination of investment choices, operations and tariffs of such an RTO going forward, but the FERC has repeatedly indicated its willingness to consider stakeholder governance issues on a case-by-case basis, so the proposed mutualized form is at least discussable at this point. To assure independence, the most likely form of governance of such a mutualized RTO would be independent of asset ownership in the leased capital base of the RTO, and the most likely form of revenue shares would be a two-part remuneration, as suggested in Kleindorfer, *opus cit. supra*, fn. 2. The first part of the revenue share for an asset would cover the fixed cost of the embedded capital of the asset, at some uniform rate of return, and the second part would recognize through average congestion payments the differential usage value of some

Any further investments in transmission assets could be independently decided by merchant transmission operators or other stakeholders in the regional market, or could be proposed and financed by the RTO. All assets put in service that are connected to the grid would be turned over (leased or sold) for maintenance and operation to the RTO once constructed.[20] Again the valuation and contracting for these would be as determined by the RTO, perhaps under negotiated terms with the party building or financing these assets.

Integrated RTO: In this form of RTO, all transmission assets would be divested by current owners and sold to the RTO, which would then operate as a commercial entity providing transmission service to all comers on equal and non-discriminatory terms, as prescribed by FERC orders 888, 889 and 2000. Any future grid investment or transmission enhancements would be the sole province of the RTO. The RTO would collect revenues to support its activities through both congestion fees as well as connection fees, with tariffs approved by the FERC.

As to existing models of these different of RTO, the autarchic model or something close to it is in evidence throughout most of the U.S. today, and is likely to be the form proposed by most RTOs in response to FERC Order 2000. The reason is that it requires the least change from existing procedures. The integrated model is what in place in the U.K. and Spain. A weaker form of the mutualized model has been proposed for the New England ISO and for PJM. The forms proposed are weaker in the sense that they do not require that all transmission assets be brought under the umbrella of the RTO, except of course for real-time control. Regulation of these three forms of RTO would be quite different. The autarchic form would require the continuation of the current many-to-many regulation, with multiple regulators concerned with different aspects of performance and revenue regulation. The mutualized and integrated RTOs would allow a more direct regulation of these more integrated actors. To allow for a period of experimentation and to assure continuing stability of revenues for existing asset owners, a likely course of action would be to use continued cost-of-service regulation based on the integrated base of the RTO, gradually moving some of the congestion and operating costs of the RTO into a form of performance-based regulation.[21] The major point to be

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assets relative to others. Maintenance and operating cost of the mutualized RTO would be covered out of a single till, the RTO's operating budget, which would be eventually subject to performance-based regulation. But this is a very complicated issue that needs to be carefully examined before we leap into another inflexible vision of the market before we experiment. For example, if utilities can manage to lock up the second part of their remuneration (perhaps through allocated FTRs) in perpetuity, they would never have an interest in cooperating with an RTO to relieve congestion and to undertake other tradeoffs in achieving efficiency in grid performance. On the other hand, if utilities and other investors cannot assure themselves of predictable cashflows going forward, the investment problems I have noted come to the fore. Balancing cashflow predictability with grid performance, and assuring that regulators and customers know who is accountable for performance, is the balancing act that has not yet been achieved.

[20] Again the role of new investors in the governance of the mutualized RTO could take various forms. The easiest is to assume, as in fn 13 *supra*, that the governance of the RTO is relatively independent of asset ownership in the capital base of the RTO.

[21] For details on various forms of transmission regulation, and transition problems to the regulation of more integrated RTO forms, see Shimon Awerbuch, Michael A. Crew and Paul R. Kleindorfer. "Governance of Transmission Networks." In *Expanding Competition in Network Industries*, in M. A. Crew (ed.), Boston,

recognized here is that the mutualized and integrated forms allow hierarchy internal to the RTO to begin to replace multi-tiered regulation of distributed owners, while beginning to hold the resulting RTO itself responsible for grid performance.

My rationale for introducing these models is to highlight the degree of market vs. hierarchy in the organization and governance of transmission investments and operations. As one proceeds from the autarchic to the mutualized to the integrated model, one sees a more decisive RTO (since it is more centralized), and an RTO that is easier to regulate (since the organizational boundaries and performance accountability of the RTO become clearer). However, these benefits come at the cost of setting up the RTO in the first place, including valuing the assets of current transmission asset owners; such costs become greater as one moves away from the status quo of distributed ownership toward more centralized ownership and control of the resources necessary to provide transmission service. Nonetheless, the August 14th blackout makes it clear that the status quo is not sustainable. In particular, the urgent matter of providing incentives for coordinated resolution of interdependent reliability and congestion problems, arguably the centerpiece of the RTO debate, will remain unresolved until we move from the autarchic perspective of "every man for himself" to the view that emphasizes the need to see transmission service provision as a business.[22]

FERC Order 2000 quite properly leaves open the question of what form the RTO should take, since different jurisdictions have very different starting points and conditions. Yet it should be clear that we must move away eventually from the current autarchic model towards a more decisive and accountable model of transmission. Absent this, and the inseparabilities and externalities of transmission investment and operation will become stalemated and problems with the current investment climate will worsen. The stalemate will be especially difficult to break for transmission investments that are of the public good variety in the sense they are required for reliable service, or to meet security constraints, but they find only limited value in terms of observed power flows on these

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MA: Kluwer Academic Publishers, 2000. Note that the "experimentation" here is not meant to describe ad hoc and unilateral changes in some elements of the system, but rather a systematic exploration of alternatives that are discussed by all stakeholders involved before implementation, and that entail carefully measured outcomes and evaluation. The idea is to understand where we are headed through tests and prototyping before mandating some change or market design issue whose flaws will only be detected under actual implementation.

[22] Seeing transmission service as a business could bring some much needed logic to the estimation of net benefits of restructuring. Using essentially a methodology of nationwide economic dispatch, the Department of Energy estimated the country-wide annual net benefits of restructuring at less than $5 billion per year. But this rather favorable estimate disregarded the increases in transmission investment needed just to sustain the status quo, which could run anywhere from $1 to $5 billion, depending on the scenario. In a wholesale market of $250 billion per year, the net savings of 1-2% estimated by DOE, neglecting transmission investment costs, are well within the bounds of random noise and may represent no new economic value creation, but merely a shifting of existing profit margins to new entrants. If one adds any sort of disruption costs to this equation, resulting from the compendium of misaligned rules, requirements and policies of the new order, then restructuring could well be a net drag on our economy. The point here is that transmission should not be a neglected afterthought, as in these net benefit calculations, but should be very evident in any representation of net benefits associated with restructuring the value chain of electric power. This notion would hardly need to be underlined if transmission service provision were considered as a business, whose value-added net of capital costs was to be maximized.

lines.[23] For a decentralized model of investment choice, this is a real problem. For a centralized model of the RTO, this is less of a problem, since the RTO will face the full consequences of running the system and assuring performance. Under appropriate forms of performance-based regulation, this clearer accountability, together with the authority to make the necessary tradeoffs in selecting investment projects, puts pressure on the RTO to make efficient choices. Issues of accelerated capital recovery and other drivers of investment and innovation will still be important under more integrated forms of RTO, but they can be more transparently resolved since assets will be under the long-term control of a single entity.[24]

A theoretical paper[25] related to this non-technical note analyzes the spectrum of choices available in setting up the business and regulatory model of the RTO. These include, foremost, the governance and decision rights of the RTO and how it is regulated. Besides the explicit requirements of FERC Order 2000 (some of which are repeated below for emphasis), we can summarize the RTO design issues at stake by asking the reader to imagine the ease of accomplishing the following needed tasks for the above models, and for others the reader may consider feasible:

- Ability of the RTO to solve the short-run and real-time control problems of managing congestion, obtaining necessary ancillary generation, and providing for economic dispatch

- Ability to plan and manage transmission system expansion, including the ability to oversee risk-based design analysis, to undertake simulation and experimental implementation of prototype proposals, and to provide meaningful feedback to all stakeholders on the status and future evolution of the regional grid for which the RTO bears responsibility

- Ability to identify the boundaries of the RTO organization and the needed revenues to support this organization for efficient short-run and long-run operation

- Ability to affect and be held accountable for grid performance

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[23] For a discussion of the separation of costs, benefits and allowed revenues based on the value of a transmission asset for reliability and security versus its observed value in use (e.g., in terms of actual power flows over the line), see Kleindorfer, *op. cit. supra*, fn. 2.

[24] The issue of capital recovery is recognized as critical in the regulatory economics literature, especially in times of change driven by entry. In the case here, entry means both potential bypass of current transmission assets by new grid investments as well as the investments in distributed generation, which may lessen the need and value of competing grid investments. There is no single recipe for efficient capital recovery rules, but depreciation must generally be accelerated when these external forces arise, or there will simply be no new investment and existing undepreciated investments will tend to become stranded. For a discussion of these issues, see Michael A. Crew and Paul R. Kleindorfer, "Economic Depreciation and the Regulated Firm under Competition and Technological Change, Journal of Regulatory Economics, Vol. 4, No. 1, March 1992, 51-61.

[25] Michael A. Crew, Paul R. Kleindorfer and Menahem Spiegel, "Reliability, Regulation and Transmission Investment", mimeo, Wharton Risk Management and Decision Processes Center, University of Pennsylvania, Philadelphia, January, 2004.

- Ability to regulate the profits and price structures of the resulting RTO in a manner that provides for breakeven operations of the RTO, while providing appropriate incentives for efficiency in the RTO's investment, contracting and operating decisions

- Ability to meet capital market requirements for raising capital for investment projects

- Ability to properly value transmission and to monetize the tradeoffs in meeting various performance standards

- Ability to respond to needs of specific stakeholders, such as native load customers for existing transmission asset owners, as well as for market participants

- Transactions costs of getting to the RTO organization from a given initial condition

Tradeoffs in the RTO design will have to be accommodated, as the design that is best for dealing with some of these problems will be non-optimal for other tasks. In my view, the key issues are the first five, related to the ability of organization to define its boundaries, be accountable as a business for its performance results, and have the decision authority for operational as well as guiding investment choices (whether built by merchants, incumbents, or through new powers vested in the RTO). I consider this matter separately in the following section.

3. Performance Accountability in RTOs: Transmission as a Business

A major question rose in several of the papers contributing to the analysis of August 14th blackouts is the extent to which an RTO can be held accountable for grid performance. It seems clear that if this is to be true in any meaningful sense the RTO must have authority for both operational control as well as grid investments.[26] Naturally, this is also recognized as a central issue in FERC Order 2000, where the key vehicle for dealing with grid investments is the planning protocol required of every RTO. Given the different starting positions in different states, we can expect to see a variety of responses to this requirement in the proposed RTOs going forward. At issue in all of these will be the differential treatment of "merchant" (or "economic") transmission investments and "regulated" transmission investments.[27] The former is any independent choice made by a qualified party to build or enhance transmission, but for which revenues are intended to be recovered from contract revenues for use of the asset or from FTRs in those ISOs

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[26] See Hogan, Hunt and Joskow, *op. cit. supra*, fn. 4. For some of the efficiency problems stemming from the interaction of transmission and generation, see also Thomas-Olivier Leautier, "Regulation of an Electric Power Transmission Company," *The Energy Journal*, Vol. 21 (4), 61-92.
[27] This discussion builds on the excellent overview of the transmission investment problem by Hogan, op. cit. supra, fn. 4.

(such as PJM) where FTRs are defined. The latter is intended to be other investments for which revenues will flow from regulated tariffs and may be subject to regulatory approval of various sorts. A great deal of discussion has already taken place about whether and how investments under both categories will contribute to a sustainable investment program for the grid going forward. I wish to underline here only one aspect of this complex matter, that associated with the various forms of RTO noted in the previous section. I will only contrast here the autarchic and the integrated forms, as the mutualized form would have much the same character as the integrated form from the perspective analyzed here.

Observe the difference between the nature of approval and implementation under the autarchic and integrated models of the RTO. In the former, the RTO will not have nearly the decision rights as in the latter. The consequence will very likely be two-fold: one is a clouding of revenue streams and resulting problems for investment, and the second is the inability to promote investments that are primarily directed towards increasing reliability of the entire system. Significant free-rider and public good problems arise naturally for such investments, so that attaining the necessary consensus for such investments will be (and has been) extremely difficult. The result is already visible with discussions of provisions for resolving conflicts through auctions of projects foreseen by an RTO as desirable, following a waiting period in which no one steps forward to undertake these. But such auctions will be run in the face of the same uncertainty that gives rise to the lack of investment incentives in the first place, and will therefore confront the same basic problem. The perceptions of cost/benefit arising from such projects across different stakeholders in an RTO/ISO footprint will be very different, and will undoubtedly give rise to high transactions costs, if they are implementable at all.[28] And imagine the resulting patchwork of regulated projects, earning very different levels of return, resulting from such auctions over time.

Contrast this rather chaotic picture with that of the integrated or mutualized RTO. It is still possible under this more decisive model to have merchant investments in transmission, but control of the resulting portfolio of investments will be in the hands (under either full leasing or outright ownership) of the RTO. The RTO would propose a portfolio of on-going projects, consistent with a coherent plan for its entire region. Some of these might be "economic" investments in the sense that such investments might earn competitive returns based on elimination of congestion costs alone. Others might be

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[28] See, e.g., Io Energy, Power Daily Northeast, December 16, 2003, which describes the on-going dispute in the ISO New England area concerning the categorization of a number of transmission projects. Currently Central Maine Power (CMP) is disputing the re-categorization of some projects, previously considered "economic" projects scheduled to float on their own bottom, as "regulated" projects that would be put into an overall grid cost allocation pool, to be funded by all users of the grid. CMP has noted that this issue is likely to trigger litigation, if the current re-categorization is allowed to stand, in that it will represent an unfair requirement for CMP and its customers to fund projects in New England for which they receive no benefits whatsoever, notwithstanding the claims of ISO-NE that such projects benefit the grid as a whole in enhancing reliability. The certain prospects of paying for "reliability investments", together with the uncertainty of revenues and associated with FTR allocations and other revenue determinants, has given rise to a growing spirit of litigation and paralysis in the industry relative to new transmission investments and capital recovery for existing assets.

"reliability" investments that are made to provide efficient grid infrastructure for anticipated demand and supply scenarios. The RTO would not be required to provide ex ante definitions of which assets were in which category, and indeed the nature and use of an asset could well change over time. The resulting asset portfolio would be remunerated according to uniform and regulated tariffs that recognize both the usage value of these assets as well as their reliability value. It would be up to the RTO to manage its own portfolio of investments to meet unfolding supply and demand scenarios according to its own judgment, now unhindered by the stalemate of competing distributed owners.[29]

The above contrast is intentionally brief, and much would need to be done to flesh out the details of regulation, of leasing arrangements, and of the decision rights and responsibilities of various forms of RTO going forward. The main point of this matter should be clear in contrasting the distributed ownership, autarchic form of an RTO with its more centralized brethren. The basic point of contrast is in RTO decision rights and the ultimate responsibility for investments to support the RTO as a regulated business providing transmission service to generators and loads. These differences will be central in determining the ability of the RTO to undertake meaningful planning and management of grid expansion going forward. Many of the uncertainties and ambiguities of the many-to-many regulatory model in place today would be considerably simplified if such an integrated model of the RTO were adopted. The obvious place to begin is with the mutualized model of the RTO, which might then give way eventually to an integrated model over time. This would also allow for a certain period of experimentation as the revenue shares for leasing could mirror the possibly changing mix of existing allowed revenue rights to specific assets, gradually bringing these under a more unified umbrella and leaving ultimate cost-allocation procedures to various asset classes to the management of the RTO.

Beyond the issue of assuring clarity and stability of revenues to support investments, the mutualized and integrated RTO models promote a central aspect of efficiency in transmission, namely a clearer focus on the RTO as providing an integrated transmission service business, with measurement and accountability for performance results. Various authors and business leaders have suggested that, just as in the revolution to customer-focused operations in unregulated markets, transmission service should be run as a business with a clear mandate for service quality standards and with a strong orientation to focus on its customers.

Performance guarantees could be incentivized by a number of means, including regulatory penalties for violation of service standards, insurance and the threat of competitive bypass of poor reliability by distributed generation.[30] For any of these to

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[29] Given the severe consequences of under-investment in reliability, it is even possible that the mutualized or integrated RTO would engage in over-investment in transmission, with some information rents in controlling this by regulators being inevitable. These sorts of problems are well-known in the regulatory economics literature.

[30] For a discussion of reliability-based pricing and insurance mechanisms. see H. Chao and S. C. Peck, "An Institutional Design for an Electricity Contract Market with Central Dispatch", *Energy Journal,* January 1997, 85-110. See also the discussion in S. Oren in S. Awerbuch, L. Hyman and A. Vessey, *Blueprint for Transmission*, Energy Reports, Arlington, VA, 1999.

work, it should be clear that the RTO must face a credible mandate to measure and provide performance guarantees. And for this, a strong movement toward either a mutualized or integrated RTO would clearly be a step in the right direction. The general metaphor here is: governance is a regulatory issue; performance is a market issue. Nonetheless, it is important to put proper governance in place if reliability and performance guarantees are to have any chance of being measured and implemented.[31]

Before concluding on the subject of risk and performance guarantees, it is important to note that this problem, like others in transmission, cannot be dealt with in isolation. For example, in today's unsettled environment, it is quite possible for one ISO to transfer significant risks to another. It is also possible that Independent Power Producers (IPPs), with no transmission responsibilities, can increase significantly the risks faced by both local and interstate transmission providers, by placing loads on the system that utilize resources that had been previous foreseen as reliability resources. IPP actions could also require significant ancillary generation support within time frames that make it difficult to provide this, or they could not adhere to good practices or established rules.[32] Thus, the issue of performance guarantees, and the risks associated with these, carries with it the same interdependency arguments as planning and investment in transmission. Indeed, the most significant problem in achieving finance-backed performance guarantees is the need to get one's arms around the RTO, to provide a structure such that the RTO could reasonably be held accountable for performance, and the regulatory structure to encourage the RTO to offer at least some limited form of performance guarantees. This general theme transcends the performance problem, and is directly related to the integrity and coherence of the RTO as a functioning commercial entity. I am convinced that moving toward this objective will require adopting a form of governance and regulation for transmission that approximates the mutualized or integrated RTO.

4. Conclusion

FERC, NERC and state regulators face an unenviable task to sorting out the current maze of conflicting rights, roles and obligations of transmission asset owners, investors and the RTO that is to manage the planning and operations of transmission going forward. In the process, a defining issue for both regulation and accountability of the resulting entity will be the scope of the RTO's decision rights. I have argued here that leaving matters as they

[31] Basically this was the approach taken to regulating congestion costs in the National Grid Company. Faced with such performance-based revenue allowances, NGC reduced its congestion costs and outage fees very substantially over the period 1994 to 2000. For details, see Paul R. Kleindorfer, Dongjun Wu, and Chitru S. Fernando, "Strategic Gaming Models for the Electric Power Industry", *European Journal of Operations Research*, March, 2000. The reason was simple in the case of NGC: they got to keep any money they saved from reducing these costs. The issue will be more complicated in the mutualized model of the RTO, as such performance-based caps would have to flow though to the transmission asset owners, even though these owners would have very little to say about the actual strategies adopted for reducing congestion costs and interruption losses. In the case of the integrated RTO, the situation would be very much like the case of NGC.

[32] My focus here is on IPPs, but similar comments could well be advanced with respect to federal power marketers, who also have incentives under current regulatory structures to oversell their capacity and put the reserve system and their networked neighbors at risk in the process.

are currently will not serve the interests of either attracting needed investment nor of serving customers well. To do so will require empowering the RTO with the abilities required for it to function independently and to have the authority to plan and manage grid expansion. Doing so through the adoption of the mutualized or integrated form of RTO will at once move the institutions of regulation and governance to a many-to-one form from its current chaotic many-to-many form. Absent this, and there will no focus of investment and capital recovery, for grid performance, nor in general for the accountability of the RTO in carrying out its long-term and short-term responsibilities. I realize that some of my economist colleagues will consider this move from distributed ownership to more centralized control of investment in transmission a move in the wrong direction, away from markets and towards hierarchy. However, as I hope my arguments have at least suggested, the strongly interconnected nature of current and future transmission systems support this movement, both for reasons of internal efficiency and coherence of the RTO as well as for the transactions costs of multi-tiered regulation. Moreover, the increased transparency that would result from this movement would be salutary for both transmission as well as for generation investors, including distributed generation, who must make projections of transmission capacity and reliability in evaluating their own investment choices.

Let me summarize my argument by articulating some basic principles that are intended to stimulate further debate on the design of emerging RTOs. I state these as prescriptive principles in the interest of stimulating this debate.

P1: A successful market and RTO design requires that the RTO have the authority and bear the responsibility for assuring performance of the essential functions of transmission service, from planning and management of grid control and expansion, through real-time balance.

P2: A successful market and RTO design requires that the RTO have the incentives to be customer focused in defining and delivering transmission service offerings, and in providing information to stakeholders on the performance and planned evolution of the transmission grid going forward.

P3: A successful market and RTO design requires that the RTO have the incentives to integrate engineering and economic aspects of grid expansion and operations; both good economics and good engineering are required for sustainable operations.

P4: A successful market and RTO design requires an organization and governance structure that will provide the RTO appropriate incentives and the autonomy to integrate investment, market interactions and engineering risk analysis without the necessity of multiple regulatory bodies to oversee and micromanage the process.

These principles point, in my view, to a much stronger decision rights framework for the RTO than the autarchic model currently in vogue. Adopting the mutualized or integrated model would at least provide one-stop regulation for the multiple regulators who continue to have vested interests in the efficient design and operation of the transmission system. Such a move would also recognize the economies of scope and interdependencies that exist in transmission networks and services. Together with a stronger commitment to performance measurement and risk-based planning, this could provide a way forward for implementing FERC Order 2000 in a manner that has some hope of providing a long-term solution for transmission service in the U.S. electric power industry.

Perhaps the most important need at this point is to find a way for researchers, investors, industry leaders and regulators to move toward a more open discourse concerning the principles needed to assure a sustainable future for the power grid. As in major risk events of the past, such as the Bhopal accident in 1984 and Hurricane Andrew in 1992, we need to take the full body of data from the August 14th blackout and attempt to learn fro it the limitations of our current mental models about how the power grid should be structured, governed and controlled. In this process, we need to move from a culture of blame to an open discourse on the very serious limitations inherent in our current approach to planning and regulating transmission service.