Creating Value through Transmission in an Era of RTOs[1]

Michael Calviou[2]
Paul R. Kleindorfer[3]
Mary Ellen Paravalos[4]

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Abstract

This paper examines the role of transmission in the electric power industry in the US from a perspective in which transmission service is viewed as a commercial activity, a business. We begin by noting a number of the problems facing transmission owners (TOs[5]), including the result of anemic investment, resulting from the wave of restructuring in the US markets in the past decade and the uncertainty about how this process will continue to unfold. We note that the current model of transmission operation separates ownership and control and, through the emerging Regional Transmission Operator (RTO) structure, lacks accountability to current and future investors and industry stakeholders, and is not focused on innovation to meet customers' needs. Notwithstanding these problems, we take the emerging RTO structure as a given, for the short run, and inquire as to how the RTO model can be improved. For the long run, we argue that creating a favorable environment for the emergence of independent transmission companies (ITCs) is the best path for resolving the tangled web of uncertainty that now confronts the transmission business in the US. In the short run, we also argue that transparent and consistent metrics on the value of transmission investments and operations should be promoted to guide and inform the regional planning processes that have emerged in response to the lack of transmission investment.

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[2] Vice President & Director, Transmission Regulation and Policy, U.S. Transmission, National Grid Company, Westborough, MA, michael.calviou@us.ngrid.com

[3] Anheuser Busch Professor of Management Science and Professor of Business and Public Policy, The Wharton School of the University of Pennsylvania, Philadelphia, PA kleindorfer@wharton.upenn.edu

[4] Director of Regulatory Policy, National Grid Company, Westborough, MA, mary.ellen.paravalos@us.ngrid.com

[5] A "TO" is defined here as an investor-owned public utility that owns and operates transmission facilities. A TO may also own and operate distribution facilities, and may also own generation or otherwise engage in electricity market activities. The US transmission grid is primarily owned by some 80 TOs [along with municipals, cooperatives and federal entities].

1. Introduction

The problem of inadequate investment in transmission in the US has been documented in several studies (e.g., Hirst, 2004; Hyman, 2003). While the severity of the problem varies across regions, it is generally recognized that there are significant problems attracting capital to transmission investments in the current environment. In part, this is the natural consequence of the problems of siting transmission investments together with the long economic lives of such investments once constructed, both of which contribute to greater uncertainty compared to other competing investment opportunities. But these intrinsic problems are clearly exacerbated by a number of other uncertainties in the cashflows needed for capital recovery of investments in transmission. These further uncertainties arise primarily from two sources: (i) multiple regulators and multiple stakeholders with no clear or consistent 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 and customers to come to grips with who should pay for reliability.[6]

These same factors make it difficult to construct a workable business model for transmission ownership in the US. Any commercial undertaking should have clarity on the rights, roles and responsibilities of asset owners, but these are clouded in the present environment by regulatory and political uncertainty, and by a lack of clear authority and responsibility to measure and guarantee performance to the customers of transmission. 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.

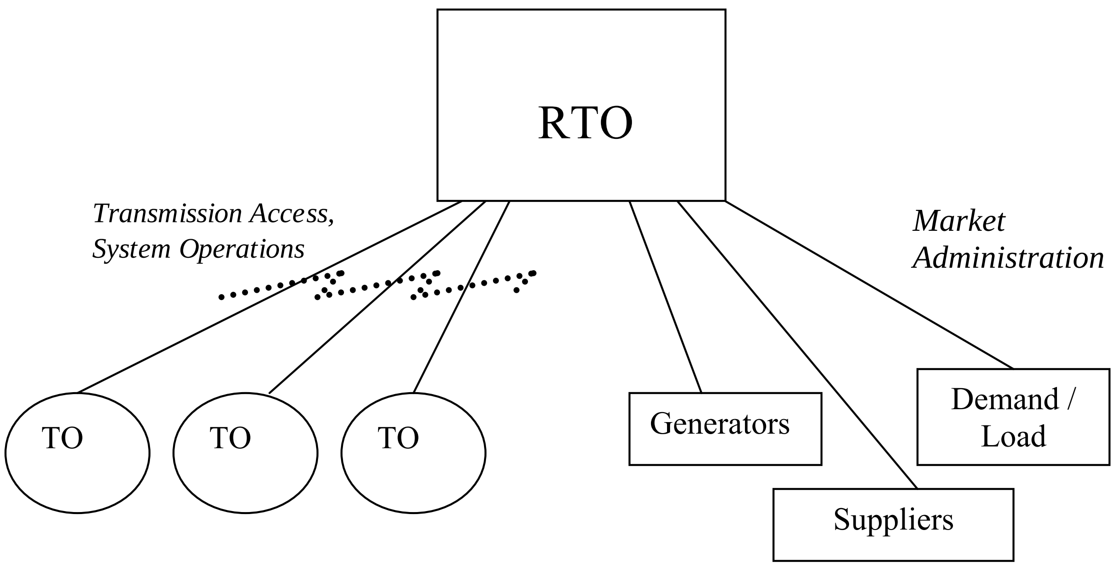
The current focal point for the transmission debate is the structure and governance of the Regional Transmission Organizations (RTOs) envisaged under FERC Order 2000. As we explore in more detail below and as illustrated in Figure 1, these (typically not-for-profit) RTOs are to have a number of functions, including those of the Independent System Operator (ISO) which is the organization having responsibility for the real-time control of system operations. For the RTOs that have been proposed to date, the ISO functions are part of a hierarchical structure in which there exists a division of transmission business functions. An example of this is a separation, and sometimes sharing, of system operation from asset ownership functions. As we discuss in Section 3 in more detail, these separations in decision rights between Transmission Owners (TOs) and the RTOs to which they belong give rise to both strategic ambiguity and financial uncertainty. Another characteristic of the RTO is a separation of energy market products from the regulated delivery function.

In addition to its ISO functions, the RTO will have several medium-term and long-run planning and monitoring functions, which are intended to identify congestion and

[6] See Crew, Kleindorfer and Spiegel (2004) for an analysis of this problem.

transmission problems, undertake appropriate planning studies to determine how to mitigate these, and propose and guide solutions via market and non-market (regulated recovery) mechanisms. Several authors, including Joskow (2004) and Kleindorfer (2004), have considered the decision rights and governance of RTOs and have discussed problems arising from the balkanization (read distributed ownership) of the transmission grid. In this paper, we take the current structure as more or less given, following various FERC orders and clarifying rulings. We ask here how a TO can operate as a business under the present arrangements, and what steps might be taken to improve the alignment of the business interests of such a TO with the interests of customers and the multiple stakeholders concerned with a well functioning transmission system.

Figure 1: Structure of RTO



We can summarize the current state of affairs in the transmission sector in the US as follows. Restructuring and visions of the Standard Market Design (SMD) and the reality of emerging RTOs propose to vest in the RTO and its subordinated Independent System Operator (ISO) real-time dispatch and balance functions, essential to the control of the grid. These real-time functions have been integrated in markets in the Northeastern US with locational marginal-cost pricing (LMP) which provides, *inter alia*, an on-going assessment of congestion costs due to out-of-merit order generation dispatch resulting from transmission constraints. Notwithstanding some progress in implementing the RTO designs and associated short-term functions of the SMD, these and other markets continue to exhibit problems on the transmission side. These include (1) concerns that the non-profit ISOs will not have incentives aligned with economic or financial realities and may tend to adopt overly conservative operating practices, or initiate ineffective or inefficient market design programs; (2) the diffuse ownership of transmission assets, leading to public good/free riding problems, including underinvestment; and (3) the several layers of regulatory governance, leading to regulatory inefficiency and uncertainty.

Added to the above list is the general sense of lack of accountability as to who actually owns the problem of assuring adequacy of transmission investment and operational capabilities. One often hears that Financial Transmission Rights (FTRs) (also known as Transmission Congestion Contracts (TCCs)) will "fix" the problem. But this is far from the truth, both in practice and in theory. In practice, the revenues from FTRs are often subtracted 1-for-1 from revenues derived from bundled transmission rates, hardly a recipe for encouraging investment based on such revenues. Such revenues could theoretically encourage merchant investments, but in practice we have seen only a handful of merchant projects proposed and the ones that have proceeded have done so on the basis of long-term contracts (and financially backed by state entities such as a state power authority) and not FTRs.

Of course, the proposal embodied in FERC Order 2000 to promote a competent solution to the short-term problem of generator and transmission dispatch is a necessary condition for efficient operation of the power system. Moreover, solutions to the economic dispatch problem are feasible and, when coupled with locational pricing and associated information support services, can provide valuable information to 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/ISO, and even solving the problem of providing proper price signals on the value of short-term congestion to generators and Load Serving Entities (LSEs), does not obviate the problem of inseparabilities and externalities in electric power provision. These problems are still there, and indeed they act in fundamental ways to condition the nature and outcome of the real-time problem the RTO strives to solve. Consider a few of the most obvious interactions, focusing on transmission (similar comments would, of course, apply to generation):

> Investment choices by transmission asset owners and distribution companies will determine the control technologies and the scope and quality of network available for dispatch by the RTO/ISO.
>
> Maintenance and other determinants of asset readiness will co-determine the real-time availability of transmission assets for security-constrained dispatch by the RTO/ISO.
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> The ability to provide for needed reactive power and voltage support will be affected by both readiness conditions of TO facilities as well as the usage of the power system in addition to contractual arrangements with TOs, RTOs, and generation sources.

These and other decisions may or may not be within the scope of the model for regulation and market design envisaged. However, 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 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 short-term model does not 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.

To deal with the missing investment elements of transmission planning, FERC Order 2000 foresees an RTO-based model of "regional planning". For example, under PJM's Regional Transmission Expansion Planning Protocol (RTEPP), which is similar to proposals in other regions, a complex six-step, multi-year process is required to assess where new transmission is required due to unhedgeable congestion costs, to determine cost allocation for required transmission upgrades, and ultimately to assure that these upgrades are constructed. There have been many objections to the RTEPP process by stakeholders, including problems with cost allocation and other issues of decision rights in the initial proposal, but the basic proposal has now been approved and has begun operations. Given the many sources of uncertainty identified above, none of the some 25 congestion relief investment projects that have been identified through the RTEPP process in PJM to date has been initiated. Of course, these projects are still in their 'market window' in which market solutions may come forward. If at the close of the market window the need still exists, then PJM may designate a TO to build the necessary regulated upgrade.

Some Common Perspectives on What Will Solve the "Problem"

It is perhaps useful to consider a number of perspectives that have been offered over the past few years as to why the power grid in the US has become a bottleneck for the entire electricity industry.. Each of these perspectives deserves a paper on its own, but our intent here is merely to provide an overview of the multiple rationales for arguing that transmission is either not a problem, shouldn't be a problem or will soon be solved if it is a problem. Without refuting any of these in detail, their contrasting differences should highlight at least the confusion in today's environment surrounding the subject.

Market forces will solve the problem, through merchant investment responding to market opportunities. The argument here is that the new market structures now clarified through RTOs and nodal pricing have begun to provide the necessary basis for valuation of new investments, in both generation and transmission, and this will soon usher in appropriate investments. The fact that we have seen next to none new transmission investments based on this model in the past few years, and that transmission system expansion is being outpaced by demand growth seems to contradict this perspective[7]. Well functioning markets operate according to transparent rules for appropriating the benefits of sound investments (those that create economic value); the rules for earning profits and for capital recovery in transmission are anything but transparent, let alone the rules for judging what is a sound investment.

Investors will do it, especially if the investment is clearly needed from an economic or reliability perspective. The noted problems of underinvestment suggest that either returns are unclear, or that they are inadequate in the sense that investors have better opportunities for investing their capital. It will do no good to rail against such investors as being "selfish" or "imprudent"; the fact that they do not invest is a performative utterance about the attractiveness of the investment opportunities. We examine in the next section of this paper the necessary characteristics in a regulated environment to attract capital. These are manifestly not present in the current environment for transmission.

The vertically integrated model (VIM) from the days of yore is the only workable solution. This view is held by quite a few traditionalists who note that at least the VIM approach worked. The counter view to this is that we have now gone too far to rebundle what has been unbundled in many jurisdictions. Moreover, unbundling and market-based approaches have delivered significant efficiency gains in a number of other countries where unbundling has occurred, including the Nordic Countries, the UK and New Zealand. Each of these has their own special history and characteristics, of course, but a common such characteristic in these systems is the clear separation of transmission from generation with central control of transmission in the hands of a regulated entity. The new guise for the VIM approach is the all-resource RFP-based pseudo-central planning

[7] Just to cite one of many statistics reinforcing this same conclusion, electricity demand in the U.S. is expected to grow by 25% over the next ten years, while President Bush's national energy plan predicts an increase in grid capacity of about 4% during the same period. See McNamara (2001) and Hirst (2004).

model of RTEPP, together with various forms of Locational Installed Capacity (LICAP) payments to generators. These add-ons to the RTO approach put increased power in the hands of the RTO and its planning bodies to do what the market was supposed to have done and did not do.[8] Given the non-profit status of RTOs, it is far from clear what will drive either the RFP process for needed transmission investments nor the level or structure of LICAP payments to generators. In addition, the VIM perspective can lead to embedded local market power of the bundled entity, and well-understood tendencies (see, e.g., Weisman and Kang (2001)) of bundled monopolists to disadvantage entrants attempting to serve their "native customers". Moreover, as Pat Wood, Chairman of the FERC, has noted, lack of independence of transmission and generation is a key precursor of lack of investment in transmission.[9] There are several reasons for this, not least of which is the role that transmission plays in restricting access to native customers and allowing the collection thereby of monopoly rents (Leautier, 2001). Financial Transmission Rights (FTRs) can further exacerbate this problem by providing disincentives for transmission investments to remove congestion that would simply erode the value of FTRs.

<u>Regulators are currently actively working on solving this problem</u> and they will solve it ere long. The problems with this perspective are manifold. First, as noted in Kleindorfer (2004), there is the on-going tension between FERC and state regulators and pseudo-regulatory bodies (e.g., NERC, RTOs); with many masters, what will the servants do? Second, the focal point for much of the FERC regulation has been on the short-run design issues, including the ISO functions of the RTO and LMP pricing. This does little to address the long-run issues of investment or grid improvement, as noted above. Fixes to this based on LICAP for generators and RTEPP for transmission have thus far not moved the impasse. Finally, performance-based regulation (PBR) is a non-starter for a distributed ownership environment, such as is currently the case throughout the US. To whom should these PBR incentives be addressed? On the basis of what metrics? How are these to be aligned with overall grid performance? How can one assure that the non-profit RTO leading the show will be motivated by metrics related to economic value creation (as opposed to adopting policies and practices that aim to increase reliability at unjustifiably high costs)?

Other solutions and other perspectives abound. Independent generators are the answer. Customer or Transmission Dependent Utilities (TDU) organizations (such as TAPS) will provide the necessary focus to move toward a better valuation process. Give RTOs and

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[8] PJM Local Market Auction proposal for long-term reliability needs is an obvious example (Docket No. EL03-236-000). The increased use of Reliability Must Run contracts in many areas is further evidence of the industry's lurch towards centralized supply procurement. Having placed one foot in the restructured world of deregulated markets and another back in the days of least cost planning, customers have sometimes been offered the worst of both worlds: stranded cost payments for the divestiture of generation whose current owners may now secure regulated subsidies while maximizing revenues in an incomplete market.

[9] Results presented by Pat Wood III in "Unlocking Transmission Investment," January 28, 2004, noted a ratio of new transmission investment of 5:1 in favor of independent transmission owners relative to those that were part of companies that had bundled generation and transmission.

the RTEPP process a chance. Trading will reemerge from the shadow of Enron to provide the driving force for new investment and risk management. The list goes on.

We have no resolution to offer in the face of the above multiple and contrasting perspectives. We have a few thoughts, however, on some of the necessary preconditions for identifying and implementing improvements to the institutional arrangements governing transmission system design and operations, using the RTO framework as a starting point. These preconditions include (1) the development, monitoring and dissemination of transparent metrics on system operations to measure the performance of the grid and the various agents who contribute to this performance ; (2) improved alignment between incentives for TOs and these performance metrics; (3) a business culture focused on creating value for customers and shareholders of the transmission business; (4) linking of engineering and science to assure a solid foundation for the competence for these institutional arrangements. We develop these ideas in more detail in the next two sections, but the general thought we would like to leave with the reader at this juncture is this: the current environment of distributed ownership and non-aligned incentives among TOs and RTOs, coupled with the lack of decisiveness inherent in the RTO governance structure, will lead to continues and more confusion and immobility unless a value-driven business orientation is implemented in the transmission sector.

2. The Functions & Value of Transmission in the Era of RTOs

Transmission was born in the early days of electricity to transport cheap hydroelectric power to remote urban locations, more generally to transport bulk supply to load centers, and to interconnect adjacent utilities to share spinning reserves and as a reliability measure for major station or line failures.[10] In the interim, and following restructuring, we have come to understand that transmission has the important additional functions of promoting fuel diversity, interconnecting distributed generation and renewables, enabling competition among generators, and providing reliability and security functions within economic dispatch. While all of these are important, we will focus primarily on transmission as a market enabler since it has been the market functions of transmission that have been at the core of the debate on its value.

The proposition that transmission is enabling infrastructure, rather than a market product, may be more easily understood through an examination of the similarities between the construction of network upgrades and the reduction of trade barriers among nations. Load pockets are, in a sense, protected markets due to their isolation from suppliers in other areas. Adding a supplier to a protected market in a given country merely compels that supplier to compete against the least competitive among the existing suppliers who have become inefficient under such protection. On the other hand, reducing trade barriers between nations grants customers access to multiple suppliers in unprotected markets who must compete not only with suppliers in the protected market but also each

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[10] Per the presentation of Steve Fairfax, "What is the Grid?" Progress and Freedom Foundation, April 5, 2004, Washington, DC.

other (and anyone who later joins them in the unprotected area) to earn customers' business[11].

It is easy to see from this parallel that transmission does not compete directly with generation just as the great seaports of the East Coast do not compete with the domestic factories that are the alternative suppliers of the international goods that flow through them. As we have now come to understand (see, e.g., Leautier (2001)), the market enabling functions of transmission include: (1) providing access to cheaper power, including reliability related reserves; and (2) increasing competition among generators. Thus, customers face a choice of paying for transmission costs, or for the absence of transmission through higher supply costs consisting of either direct (e.g. fuel) or indirect costs related to reliability or environmental factors. Given the lagging investment climate in recent times, the costs of many transmission projects are small compared to the benefits they bring.[12] The cost/benefit calculus for transmission is intuitive, based on these functions, but nonetheless quite complex because it must done against a multi-year horizon, with demand and technological uncertainties, reliability and security constraints, and against the backdrop of location and timing decisions of new generation. A major research question is, in fact, the determination of appropriate guidelines for determining when new transmission investment is welfare enhancing.

Absent sufficient transmission, new entry is restricted, local pockets of market dominance develop, inefficient solutions to backup power flourish, energy and capacity prices become more volatile, and average cost and reliability of energy supplies suffer. Assuring adequate transmission capacity, including the necessary control technologies, requires the resonant interplay between the financial consequences of decisions related to electric power and the physical system within which these decisions play out. Figure 2 below is a summary of the interactions between the financial and physical systems, and shows this as occurring in four time frames: long-term, medium-term, short-term and real-time.[13] From the perspective of the above discussion on the investment gap, the current regulatory climate, and the implementation of FERC Order 2000 (and its immediate predecessors), the following two issues are key:

> First, the complexity of short-term and real-time control of the instantaneous balance and voltage and frequency requirements of modern power systems require that scheduling, dispatch and control of transmission and generation assets occur in centralized fashion. Thus, we have the recognized necessity of the short-term and real-time control functions, currently performed by the Independent System

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[11] The proposition that transmission development will drive the creation of new supply and economic development in remote areas is assumed as part of the analysis of proposed "economic upgrades" in MISO Transmission Expansion Plan. (see http://www.midwestiso.org/plan_inter/documents/expansion_planning).

[12] A recent study of the benefits and costs of new transmission by ICF Consulting estimated that $8 billion of improvements to the nation's antiquated transmission system the nation would yield net savings of $176 billion to customers on $12 billion of investment between 2004 and 2030 due to reductions in congestion, operating reserve costs and economic harm as the result of outages. See http://www.icfconsulting.com/Markets/Energy/doc_files/US-transmission-grid.pdf.

[13] See Fernando and Kleindorfer (1997) for a more detailed discussion of the interactions between physical and financial systems depicted in this Figure.

Operator (ISO), with responsibility for controlling the physical functions of the electric power system in or near real-time.

Second, decisions about transmission infrastructure belong to the long-run time frame of Figure 2, and will depend fundamentally on investors' perceptions of their ability to generate sufficient revenues to recover investment costs, plus returns, as well as ongoing costs of operating and maintaining these assets.

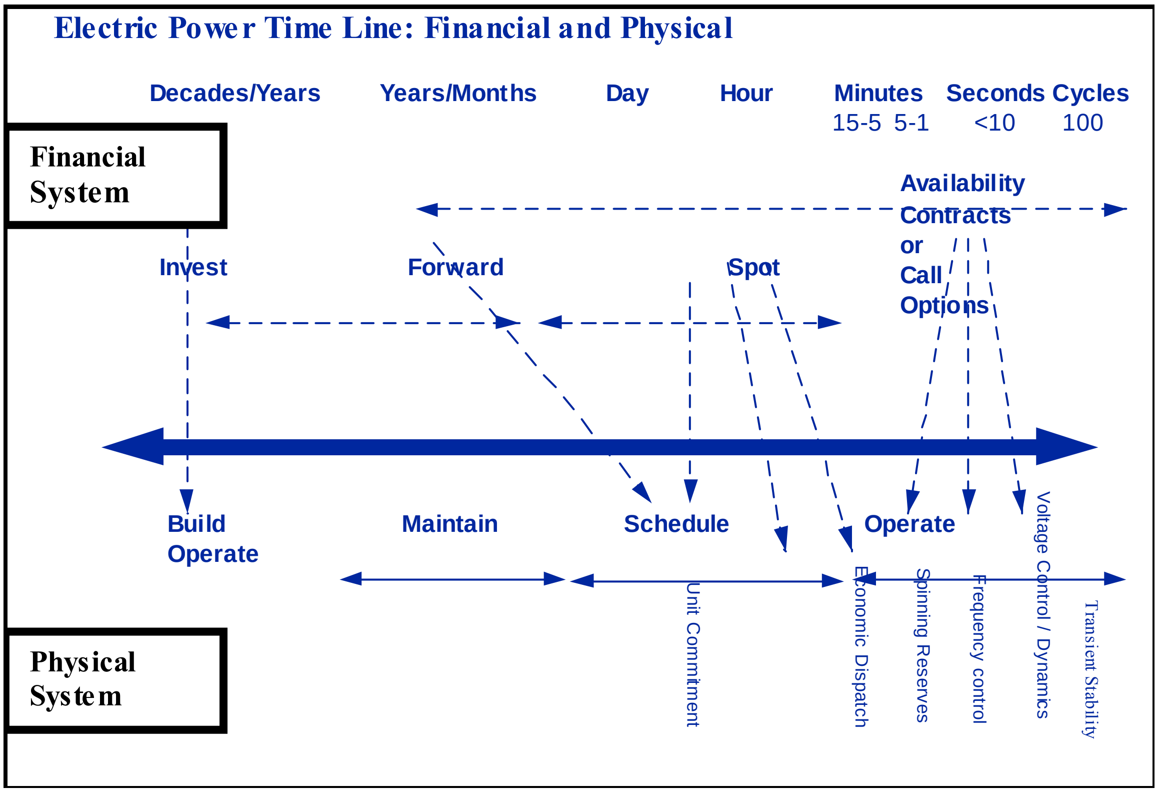

Figure 2: Market and Physical Time Lines of the Electric Power System

The difference between the long-run perspective of potential investors and the short-run dictates of controlling the physical system has given rise to a fundamental tension in regulation of the electric power system in general and transmission in particular. On the one hand, there is a need to set up strong, centralized organizations, the RTOs of FERC Order 2000, to ensure that operational authority and responsibility for short-term reliability is in the hands of those independent from the marketplace and able to identify regional problems and solutions. On the other hand, the requirement that investors see opportunities to recover invested capital, plus a competitive return, requires attention to the level and certainty of cash flows that will accrue to specific assets should these be put in place. The key problem we face is that transmission regulation has lost its sense of balance in this tension. The discussion and debate has been centered on assuring the authority to ISOs and their RTO descendants to execute their short-term and real-time functions, and very little attention has been given to assuring the clarity and adequacy of overall cash flows to asset owners or the efficiency of the transmission system operation as a whole.[14] As a result, transmission assets have faced considerable uncertainty about the level, structure and sources of revenues to cover their expenses. The result has been the noted investment gap and a growing sense of anxiety that the situation is deteriorating.

Contrasting the Days of Yore and Transmission Governance in the New World

Here are some cherished beliefs (that may be proven myths) of economists and others.

> Competition is good or at least feasible in electric power. Moreover, transmission and generation are substitutes and compete with one another, and so competition between generation and transmission should be promoted at an unbundled level.
>
> The temporal scope of regulatory uncertainty is much shorter than the investment horizons of potential investors (so regulatory uncertainty is a manageable problem for transmission investments).
>
> Someone has developed the theory and regulatory technology to regulate multi-owner systems with complex interdependencies, such as are typical in electric power systems and among transmission owners and operators.

In our view, there are significant qualifications on each of the above beliefs and these qualifications have to do with the problems of internalizing the complexities of short-term congestion management and grid control, and aligning these with financial incentives for efficient investment and operations. In the days of vertically integrated investor-owned utilities (IOUs), there was no problem with the internalization, but there were efficiency problems that have been the subject of several decades of research in regulatory economies.[15] The vertically integrated IOUs internalized all of the decisions within their organizational boundaries. Regulation, whether cost-of-service or performance-based, could be argued one-on-one with the regulator, with agreed benchmarks for the level of allowed profits/returns, for end-use tariff structures and for integrated planning covered by the same umbrella. Indeed, almost all the theory of regulation in economics has as its model this simple case of a single, regulated entity determining prices, profits and outputs in interaction with a single regulator.

The situation in the new world of electric power is far different from this. In the post FERC-2000 unbundled world, multiple TOs must cede operational control of their assets to their responsible RTO. How does such an owner value such assets and determine whether revenues committed to these assets make the business worthwhile? The costs of

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[14] This problem has also affected other participants in the electric power market as well, but considerably less so. Generators are better able to match their capital recovery and operating expenses with identifiable revenue streams, and distribution companies have the ongoing assurance and umbrella of focused state-regulation that provides reasonable clarity that they will be able to recover investment and operating expenses under the traditional regulatory contract.

[15] See, e.g., the review paper by Crew and Kleindorfer (2002) which surveys the history of the regulatory economics literature in the past few decades.

transmission assets are predominantly (read 85-90%) fixed and readily computed, once the asset is in place (of course, before the fact, there may be some uncertainty). Long-term revenues are a different matter. The revenue streams to owners of these assets could include (besides allowed operating and maintenance costs) returns dictated by FERC, by state public utility commissions (PUCs} and by their own point-to-point merchant activities. They could also include the proceeds of congestion management pricing (FTRs) if the owner has been allocated or purchased such FTRs, and they could be strongly affected by the decisions of other participant-owners in the RTO. At the same time, depending on whether the owner in question is a traditional utility[16] or some other entity, the owner may have synergistic retail operations aligned with the use of the transmission assets. In such a world, a major question of valuation of such assets arises, both before and after investments are made. This is especially true in the current environment of change and regulatory uncertainty.[17]

Added to the above problems for new investments is the governance of choice for new investments (and possibly for other decisions, such as maintenance). According to the FERC Order 2000, the RTO is to have primary responsibility for managing the planning and evaluation of required investments. If the RTO is a for-profit, regulated Transco, which owns or leases all transmission assets under its control and which makes independent choices for new investments, then the traditional models of regulation can be readily adapted to put pressure on the Transco to operate efficiently, to meet performance standards, and to do so while achieving fair and sustainable rates of return on invested capital in its operations. The clarity of this situation, both on the physical side as well as the organizationally co-extensive financial side, has led several commentators, including the authors of this paper, to recommend this type of RTO.[18] But suppose the current not-for-profit, multi-owner umbrella form of RTO is the modus operandi for the near future. What can then be done in the non-profit RTO with distributed ownership? Here the route is less clear. Any sustainable solution must begin by addressing the problems of regulatory uncertainty and commitment identified above.

In particular, the adoption of sensible, pragmatic regional transmission planning (the RTEPP-type process) can determine additional market and regulated options for

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[16] According to Edison Electric Institute figures, some 412,000 miles of the total 608,000 miles of the U.S. transmission grid is on the books of IOUs.

[17] FERC Order on Regional Through and Out Rates (RTOR), Docket EL02-111 (July 23, 2003), is a case in point. The original order required the elimination in MISO and PJM of RTOR by November 1, 2003. But barely before the ink dried on this order, FERC announced that it will not enforce the elimination, conducting instead of series of hearings and technical conferences to determine the ultimate outcome. The new date for ending RTOR rates is the end of 2004, but this history indicates the usual uncertainty around specific regulated revenue streams and longer-term ambiguity about how existing RTOR rates will be replaced or balanced by new revenue sources

[18] See, e.g., the argument in Awerbuch, Hyman and Vesey (1999). In England and Wales, the Nordic Market, the Netherlands and Spain, independent Transcos are responsible for transmission system development under regulatory oversight. Transco investment has produced a strong network platform for markets. Indeed, England and Wales, when adjusted for market size, have invested at a rate over three times that of the US. The same Transco model has worked well in achieving reasonable returns for shareholders in the respective companies and providing strong improvements in the management of the grid and of congestion costs.

customers, but it must also help to ensure that some of these are actually built. This means a regional planning process managed by an independent Regional Transmission Organization (RTO) that identifies system needs for reliability and economics, allows market participants to respond to those needs and permits regulated transmission upgrades if market participants fail to respond. Such a process should provide stakeholders sufficient opportunity for input but contain a well-defined timeline and milestones so that transmission proposals that have been fairly scrutinized and deemed cost-effective may be constructed in a timely manner. This approach allows the market to work effectively for customers but recognizes that the failure of markets to react should not mean that customers should pay suppliers monopoly rents indefinately when a regulated transmission solution exists.

In conjunction with regional planning a pricing regime should be established that features default cost allocation principles for new transmission construction rather than a case-by-case approach that incites endless debate over "who benefits" during the project's life.[19] Delay of these projects after the market did not meet customer's needs only continues the economic or reliability harm to customers.[20] The adoption of an upfront cost allocation methodology also offers the best prospects for the construction of voluntary participant-funded transmission projects[21] as it provides customers with greater certainty on cost allocation of backstop regulated transmission projects.

Finally, in order to be effective these changes must be coupled with more streamlined siting processes that acknowledge~~s~~ transmission's role in bringing low-cost, environmentally beneficial generation to constrained areas that require strong market power mitigation of generators that may be more environmentally harmful.

Beyond these elements of improved regulatory commitment, we argue below for the development of a system of clear and transparent metrics for the RTO and its subsidiary TOs to track performance of the grid and of transmission asset and service providers in this process. This should allow over time a better understanding of what organizations and what processes (in both RTOs and TOs) are creating value for money. If these metrics are to be meaningful and legitimate, and not just window dressing, they must be connected to the financial and operational outcomes of the TOs as businesses. How this is to be accomplished in an age of RTOs is the subject to which we now turn.

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[19] The prolonged debate over beneficiaries from the proposed transmission upgrades in southwest Connecticut demonstrates how clearly needed transmission infrastructure improvements may be delayed when evaluated on a case-by-case basis. For a discussion of approaches to the regulatory treatment of transmission pricing, see Kleindorfer (1998), where it is argued that a two-part pricing mechanism is appropriate, whereby the fixed costs of transmission systems are recovered in fixed fees and the relatively less important variable costs of transmission are recovered from uplift and energy-transport based prices.

[20] Though we agree that most market solutions will not eliminate the need for additional transmission investment, we recognize that some regulators may wish to afford the market some additional period to respond, as PJM has in its RTEP process through the provision of a market window.

[21] Voluntary participant-funded projects are financed by customers who are able to agree on how the costs of such projects are allocated amongst them. There are clearly a number of obstacles to achieving a consensus on such "voluntary" funding.

3. The Business of Transmission

3.1 Business Functions

And so what is the business of transmission? Certainly, transmission business refers to the delivery of quality service at a reasonable price. There are clear indicators of quality service, and these may include such things as uninterrupted power delivery, power quality of sufficient voltage with minimal harmonics and fluctuations, and responsiveness to customers' requests. However, there are less obvious, but nonetheless important, indicators of quality transmission service. For instance, the availability of transmission facilities is an important measure toward the overall reliability of the system. Although the outage of a particular transmission facility may not be obvious to the transmission customer, because no power interruption may result, the ability of system operators to respond to further disturbances and other contingencies is diminished with the overall state of reliability of the system reduced. Another important indicator of quality transmission service is its ability to facilitate a robust competitive electricity market. Indeed, lack of transmission facilities and capability has serious negative effects on the industry's ability to produce working electricity markets. We only have to look at the many examples around the country of bottled-in efficient generation that is unable to reach load centers, above-market-cost contracts to sustain economically inefficient generation sources near load centers, and large and sustained electricity price differentials between areas.

The business of transmission incorporates all the functions and activities related to the provision of transmission services. Historically the transmission asset-owning utility (TO) generally performed all these functions. With the advent of ISOs and RTOs, we are experiencing the bifurcation of transmission functions into those performed by the RTO, those performed by the TOs in an RTO region, and some functions shared between them. This separation of transmission functions itself is evolving, with an apparent trend that the RTO take on more transmission functions over time as it matures. Later, we will discuss how this trend contributes to the problems we are seeing in the industry. For now, we attempt to present the range of transmission functions and activities along with an indication of a typical split of performance between the RTO and the TO (see Table A below).

There are differences in functionality between the existing RTOs. For instance, an RTO's system control function may include control area balancing and interchange (as we see in the northeast US), or it may be more of an oversight coordination of individual TO control area activities (as we currently see in the midwest US). Similarly with the planning function, the RTO may perform the network planning for its region, or it may act more as a coordinator and reviewer of individual TO network plans.

Table A: Transmission Business Functions

	Transmission Function	Activities	RTO	TO
1	System Control	• Security analysis • Transmission dispatch • Generation dispatch • Ancillary service dispatch	√	√ (local area security, switching)
2	Operations	• Operational field switching • Maintenance field work • Asset replacement • Safety management		√
3	Planning	• Operational planning • Ancillary services planning • Generation operations policy and planning • Maintenance planning • Asset replacement planning • System design	√ (network planning, outage coordination)	√ (asset maintenance, system design, customer connection, outage planning)
4	Building New Investment	• Financing • Capital Planning • Asset procurement • New Customer connection • Engineering design • Siting • Construction		√
5	Regulation	• Tariff and rate design • Regulatory management	√ (RTO costs and rate design, market design)	√ (TO revenue requirements and transmission rate design)
6	Commercial Interface	• Tariff billing / collection • Ancillary services procurement	√	√ (provide inputs, e.g. revenue requirement, loads)

3.2 Business Drivers

Bifurcation of Transmission Functions

The bifurcation of transmission functions, as demonstrated in the above Table A, will require the determination of which entity has ultimate decisional authority over a function and associated responsibility and accountability. This is of no small consequence to the issues we explore in this paper. Indeed, getting an appropriate bifurcation of transmission functions between the RTO and TO (assuming there is one) is pivotal to the success of the transmission business sector and its ability to provide value through its role in electricity markets and reliability to the customer.

Why is this so? We expect that a transmission business, in order to function as intended and deliver quality service, must have requisite control over its assets and activities. To the extent that an RTO has decisional authority over, for instance, what network system improvements a TO should make (and when, and perhaps how), this will have a direct effect on how a TO performs its related financing, asset procurement, and construction processes. If there is any misalignment between the business motivators of the RTO and the business motivators of the TO, then the intended outcome may not be delivered or at least not economically efficiently so. Besides the obvious potential of misalignment due to the very existence of a bifurcation of transmission functions, we can also examine the potential misalignments that come out of other business drivers.

Non-profit vs. For-Profit

An independent for-profit TO is motivated to deliver value to sustain and increase the attractiveness of its business to its customers, its shareholders and the investment/finance community. Such motivators tend to lead to business cultures within TOs that focus on customer requirements, best practices, long term business growth, technical competence and indeed excellence. In addition to financial motivators, a TO is subject to a regulatory discipline through its state and federal regulators. Regulators approve rate recovery mechanisms for a TO, and may disallow cost recovery (at shareholder's expense) for costs that are not prudently incurred. The financial and regulatory motivators affect business decisions of the TO and serve to encourage results of customer value creation and cost efficiency.

All of our US examples of RTOs (and ISOs) contain a non-profit business model. As such, RTOs have no shareholders to bear imprudently incurred costs, and necessarily must pass through all costs to other entities. Thus, a non-profit RTO's decisions are likely to be substantially divorced from the issue of cost recovery compared to a TO. For example, an RTO is likely to focus on assuring reliability without due consideration to cost efficiency. We can see these concerns manifest in the Federal Energy Regulatory Commission's (FERC) recent Notice of Inquiry regarding cost oversight and recovery practices for RTOs and ISOs, in which FERC acknowledges and seeks input regarding the differing motivators that exist between non-profit RTOs and for-profit utilities and the resultant effects on business outcomes such as cost efficiency.

Transmission Ownership Fragmentation

Besides the bifurcation of transmission functions between an RTO and TO, and the non-profit vs. for-profit business motivators, there exist other important drivers that affect outcomes related to the delivery of value through the transmission service business. The current state of fragmentation of transmission ownership and operations affects the efficiency of performing the transmission functions shown in the above Table A. Also affected are prospects of regional value creation (e.g. regional competitive markets). There are upwards of eighty (80) or so investor-owned electric utility holding companies in the US. Additionally, there are [hundreds] of municipals, cooperatives, and federally-owned transmission entities that together with utilities present a virtual patchwork quilt of transmission ownership and operation across the country. Indeed it is this hugely fragmented transmission ownership that helped yield RTOs as a starting point for regional coordination of transmission activities.

Market Activities of Transmission Owners

The other driver that led to the creation of RTOs, and indeed continue to affect the value creating ability of transmission as a business, is the electricity commodity and market activities and interests of transmission owning entities. Relatively, the commodity and related market activities generate significantly higher volumes of cash flow than those related to transmission service functions. This tends to lead to an entity favoring to focus on commodity activities and can distract from business resource and attention to transmission functions. Moreover, a TO with market interests may find itself in a position to have to decide on a market action that conflicts with transmission service quality and cost objectives. Or a TO may have business motivations that lead to transmission actions (or inactions) to favor a market related financial position such as electricity prices paid or received, or FTR payments or revenues. The existence of an RTO may mitigate the ability of a TO with market interests to negatively affect transmission service, but will not eliminate it.

Rate Recovery Mechanisms

Rate recovery mechanism for transmission operational and capital costs can have an important effect on the achievement of desired outcomes of transmission service. As with any business, the cashflows associated with the business functions need to be clearly understood and adequate. Further, in order to result in desired outcomes with respect to transmission service value, the mechanisms for cashflows must exist such as to align with the business decisions needed to produce such desired outcomes.

We see in some parts of the US that regulators allow transmission costs to be “passed through” in their entirety (assuming prudence review) to customers. If a TO spends $150 million this year for operations and capital-related activities including return on investment, it is allowed to recoup $150 million that year (or perhaps with an element of time delay). If the TO spends (prudently) more or less the next year, the TO collects accordingly more or less. While this may be considered superior to a non-profit structure, this type of recovery mechanism permits certainty of revenue stream and provides flexibility in response to business environmental changes. However, as analyzed in painful detail over the years by regulatory economists, it does not by itself encourage efficiency nor innovation, since whatever costs the TO can show as prudently incurred, it is allowed to recover. This mechanism neither rewards good business decisions nor penalizes poor ones. The mechanism can, however, help to encourage investment in the transmission system. Indeed, cost recovery must include an appropriate allowance for capital costs, and the inclusion of this asset-based payment may provide incentives for gold-plating or overinvestment in order to grow the rate base, in line with the well-known arguments of the Averch-Johnson effect,

Multi-year fixed rate mechanisms are in effect in much of the country. Such mechanisms are usually bundled to include transmission and distribution components. At the end of the multi-year rate period, the rates are reviewed and fixed again for the duration of the next rate period. This mechanism can encourage efficiency in that the TO keeps the savings it creates (assuming that the regulators allow those savings to be ultimately retained), however, this may occur at the expense of performance. Such a mechanism may encourage a TO not to spend nor invest, even when it is desired or warranted. Also inherent in this mechanism is significant uncertainty regarding the setting of revenues for the next rate period. This can encourage a shorter-term approach by the TO in its business decisions, which can be to the detriment of long term transmission service quality objectives.

The concept of market returns (e.g. "merchant transmission model") associated with transmission investment and operation has been introduced and explored over the last few years. This concept has the TO derive its revenues from the provision of transmission capacity that electricity market mechanisms would then reward (e.g. FTRs). Although this concept has some theoretical attractiveness, it has had limited success in practice. Further, this model, even theoretically, would only address a portion of the transmission service needs of customers, that being related to economic electricity market performance. It is not a suitable mechanism to comprehensively address reliability and competitive market objectives.

Performance based rate (PBR) recovery mechanisms for transmission service have been considered and explored for several years. Indeed, there are several working examples of PBR mechanisms for distribution service. A PBR for transmission service, properly designed, could serve to reward desired business outcomes, and penalize poor ones. Based on measurable metrics, the regulator would allow the TO increased financial returns if, for example, agreed-upon system reliability metric objectives were met, or if congestion costs were reduced. Inherent in this mechanism is a greater level of risk, and also reward, for a TO entity relative to either the flow-through or fixed rate mechanisms discussed above. However, the ability to design and implement PBR for transmission is limited given both the fragmented and diffuse ownership of transmission and the bifurcation of transmission functions between TOs and RTOs. A PBR mechanism requires that the TO has enough control over the outcomes of its business decisions to be able to manage its risk and reward.

State and Federal Regulatory Jurisdiction

The last driver of transmission value creation we mention here is the split, sharing, or ill-definition of regulatory jurisdiction between state and federal entities. A TO entity is usually subject to both sets of regulators as it relates to it transmission functions. The objective of an individual state regulator often does not align with the regional or national objectives of a federal regulator. While federal regulators strive for broad regional electricity markets with overall net consumer benefit, a state regulator is necessarily charged with protecting the economic and reliability interests of its state citizens, and not those of a neighboring state. We can see this tension in the example of a state containing bottled-in economic generation with resultant low electricity prices. Increased transmission capacity to address the bottleneck will have the effect, at least short term, of raising the electricity prices in the subject state. However, the workability of competitive markets from a *regional* perspective would be improved with the elimination of the bottleneck. A TO that is striving to respond to both sets of its regulators will find itself in a pinch!

3.3. Business Decision Making

Each of these drivers contributes to how a transmission entity approaches decision making associated with its transmission functions. The alignment of these drivers can result in customer value creation, however as more often is the case, these drivers, either by themselves or due to its conflict with other drivers, can impede upon the creation of customer value.

The number and nature of business decisions that affect customer value in transmission service is large and complex, and not surprisingly, resembles that of virtually any other kind of business. We present for the reader in the table below (Table B) some examples of relevant business decisions by transmission function.

By a consideration of the significant drivers and an identification of business decisions, we can begin to draw conclusions about the ability to deliver customer value through the transmission service business. These conclusions are that, under the present RTO and regulatory structures, incentives for creating customer value are muted at best. Even where there are such incentives, the mixed responsibility for decisions across TOs and the RTO will likely erode or blunt the incentives to serve customers or make investments. Rather, the cost-of-service mentality imbued for years in the era of vertical integration continues for bundled T&D providers, with all the traditional inefficiencies of that mentality and further exacerbated by the lack of accountability across TOs for problems that require joint solution.

Table B: Transmission Business Decisions

	Transmission Function	Business Decisions
1	System Control	◊ Determination of available transmission system capacity ◊ Dispatch approach for reliability and economic efficiency objectives ◊ Choice of technology for system operation and measurement
2	Operations	◊ Development of in-house field force expertise vs. use of contractors ◊ Installation techniques ◊ Commitment and approach to safe practices
3	Planning	◊ Design of planning process and criteria ◊ How far in advance to plan/forecast asset needs ◊ Asset replacement and maintenance practices ◊ Spare equipment management ◊ Development of technical expertise vs. use of outside consultants ◊ Choice of asset technology ◊ Coordination with neighboring systems (other TOs or other states)
4	Building New Investment	◊ Raising of requisite capital ◊ Engineering design specifications ◊ Procurement process and vendor relationships ◊ Siting management ◊ Construction techniques
5	Regulation	◊ Design of rate recovery mechanisms with regulator ◊ Customer cost allocation methodology ◊ Management of regulatory relationships and processes
6	Commercial Interface	◊ Choice of billing system and procedures ◊ Uncollectible revenue management ◊ Customer Service
	Overall	◊ Number of resources ◊ Auditing performance and results ◊ Delivery of Investor expectations

How do we know when customer value is being created? Certainly, high reliability and low electricity costs are obvious and ultimate measures. But there are other indicators of the ability of a transmission business to make the “right” decisions that lead to customer value creation. For instance, transmission investment activities would not be stalled or sluggish. Consolidation activities would occur, such as merging of transmission ownership to capture synergy benefits from larger business “footprints”.

TOs would adopt a long-term view on forecasting needs which would allow for favorable pricing from equipment vendors, as opposed to responding to equipment failure by paying higher prices. Longer term forecasting and planning would also provide for managed aggregation of work, labor, and equipment at reduced costs. The development of sustained vendor relationships would lead to quicker response times, competitive prices, and new product and technology development. Choices of technology would account for near-term capital and installation costs, but also operations, maintenance, and performance over the life of the facilities.

There is more. We would see the industry maintaining and improving its technical expertise, so as not to be caught in a labor shortage. An impressive science and engineering culture would exist to deliver technical excellence. A long-term approach to the workforce would have sufficient in-house resources, flexed up or down through efficient use of contractors. We would see innovation and expertise from transmission entities in managing the complicated regulatory structure in an effort to deliver customer value. To be sure, one would find some of these indicators in existence today. But we suggest that the examples are too few and far between.

4 Improvements to the Current Situation

Let us assume that the current environment of RTOs and its associated institutional arrangements continues for next few years. What can be done to address some of the key challenges for TOs in this environment? We see three fundamental initiatives that need to be undertaken: (1) better metrics; (2) clearer cost recovery mechanisms; (3) improved regional planning processes. Let us consider each of these in turn.

Metrics

If the world of the typical TO is chaotic, uncertain and subject to murky decision rights on key drivers of business performance and customer value creation, then at the very least, we should begin the development of comprehensive transparent metrics on performance. These would provide markers for a more informed discussion of the direction policy should take. We leave the detailed assessment of performance metrics for future research, but the principles of the matter are relatively straightforward from the past decade of reforms in the managerial accounting profession triggered by the Kaplan and Johnson (1987) wake-up call on Activity Based Costing. These principles suggest that the basic services of an organization (here those offered by the combination of TOs and RTO) be structured into their underlying activities/processes. The value added of these processes for intermediate and end customers is then assessed, including cost, time and quality features of relevance to these customers. The causal network or driver structure underlying changes in the metrics is then analyzed and design changes are then evaluated against the projected costs and benefits of such changes as determined by the driver structure and the valuation of the customer value metric involved.

These metrics could include the following (the designations "R" and "N" included here will be explained below):

- Costs associated with transmission constraints (R)
    - Congestion costs
    - Operating reserves costs and Reliability Must Run contracts
    - Installed Capacity costs
- Costs of Transmission Losses (R)
- Number and duration of service interruptions due to transmission (R)
- Costs associated with the value of lost load and low voltage events (N)
- Transmission facilities availability (N)
- Performance of transmission outage management (N)
- Customer satisfaction (N)
    - Interconnection studies
    - Interconnection construction
    - Billing and Credit

Not only is the actual measurement or value of a metric important, but an understanding of what actions contribute to the metric (and taken by whom) is as important. The first part, metric measurement, will describe how well transmission service is being delivered. However the second part, causal linkage of a metric to actions, is the key to beginning to envision appropriate regulatory mechanisms and business structures to achieve desired results.

Some of these metrics are quantified today, however inconsistently across regions. Most RTOs/ISO produce metrics related to transmission constraints, or congestion costs. Most RTOs/ISOs do not produce a congestion metric that encompasses all of the components related to transmission constraints. For instance, energy-related congestion costs are commonly reported, although the measurement approach may vary. Capacity and reserve-related costs are not commonly reported. Costs of the value of lost load are beginning to be explored as pertaining to transmission[22]. System availability and performance data is more commonly reported for distribution or combined distribution and transmission systems.

We can begin to consider whether a metric should be measured and considered on a regional basis, or whether it may be considered without regard to the diffuseness of transmission ownership and operation, or bifurcation of transmission functions. The

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[22] See "Profiting from Transmission Investment", Ofori-Atta, Roseman, Saha, Stuart, Lipschultz and Smidt, *Public Utilities Fortnightly*, October 2004.

main question we ask is whether regional actions, or actions taken in a neighboring system, are likely to significantly affect the measurement. We designate in the list above those metrics for which regional measurement is likely needed with an "R" and those for which regional measurement is not likely to be needed by an "N".

The issue of determining an appropriate set of metrics, including their scope of measurement, remains one of the critical needs for recognizing where improvements in the current system are needed and who needs to undertake these.

Cost Recovery

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. 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 unpredictability of the distribution of profit outcomes that undermines investment or, equivalently, that drives up the risk premium so high that it becomes too expensive to finance particular projects.

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.[23] 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.

These traditional requirements for investment are not satisfied for many if not most transmission projects in the present environment. 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. Exacerbated by the transition state we are in, existing and FERC-proposed pricing regimes are not viewed as stable, making the problem of profit predictability and capital recovery immensely uncertain.

[23] See Kleindorfer (1998) and Vogelsang (2001) 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. It is argued 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.

As a business in today's environment, transmission is in a precarious state. Economic and reliability investments are often artificially separated in the RTO regional planning process. 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 a forced auction 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. The key to reestablishing stability is a framework that clarifies the sources and principles underlying adequate cashflows and capital recovery for prudent transmission investments and operations. The foundations of this framework, in transmission pricing and in the form and governance of regulation, must be one of the key research priorities going forward.

<u>Regional Planning Process</u>

Finally, while we do not explore this issue in detail here, monitoring and improving the emerging regional planning processes for transmission will be the third central ingredient of promoting sustainable operations for TOs in the age of RTOs. Several models for the Regional Transmission Planning process are currently being discussed and some theory is developing (see Crew et al. (2004)), but, as the above discussion should make plain, developing a process that balances current stakeholder rights and needs against the needs for efficiency and reliability investments is both a subject of intense research as well as policy interest. At the least, a better understanding of appropriate cost-benefit frameworks for evaluating transmission enhancements needs to be vetted, and this extends well beyond the current approaches based on congestion cost and near-term reliability concerns.

5. Direction for the Future

The suggested improvements under the current RTO model can lead only to incremental overall improvements to the recognized problem areas and vulnerabilities. We now turn our attention to consider an alternative industry model, which we argue has the potential for improving expected performance and outcomes.

We see in the previous Table A the bifurcation of transmission business functions between an RTO and TOs. What has driven the assignment of functions to an RTO includes a desire for system operation to be independent of market participants and therefore buffered from individual actions a TO may take to favor its own market positions. A further desire is an ability to regionally perform functions without being hampered by non-meaningful and many TO corporate or state boundaries. However, the actual ability of an RTO to counter these concerns is limited, given the large and varied number of functions that, in fact, make up the transmission business and that lead to the overall outcome of transmission service, and the inability of the current model of RTO to undertake all the transmission functions (some bifurcation of functions between the RTO and TOs is necessary).

An interesting observation is that an investor-owned transmission industry segment, independent from market activities such as buying and selling electricity and associated market mechanisms such as FTRs, can address the two concerns that initially led to the RTO model. Firstly, if vertically integrated utilities divest their transmission into such independent transmission companies (ITCs), then their ability to affect transmission actions (or inactions) to favor their market interests would be eliminated. Secondly, the ITC industry segment would naturally consolidate into fewer providers, of larger size, and with more appropriate geographic footprints. These consolidation decisions would be made on expected economies of scale and transactions cost savings in TO functions. In the end, however, there remains the question as to what is the preferred model. The answer to this comes in part from considering the likely outcome with regard to useful metric development, alignment of cashflows, and regulatory structure.

Let us consider sufficiently large footprint for-profit ITCs that own and operate transmission facilities to provide transmission service. The scope of the footprint is significant with regard to metrics, because of the need for certain important metrics to be considered on a regional basis. Ideally, we may consider that an ITC that approaches the size of a market or RTO would have the ability to contain all of the metric measurements discussed above. The importance of this of course is that PBRs may be constructed around metrics, and so for an ITC with sufficient scope, an effective PBR may be designed and applied to that ITC.

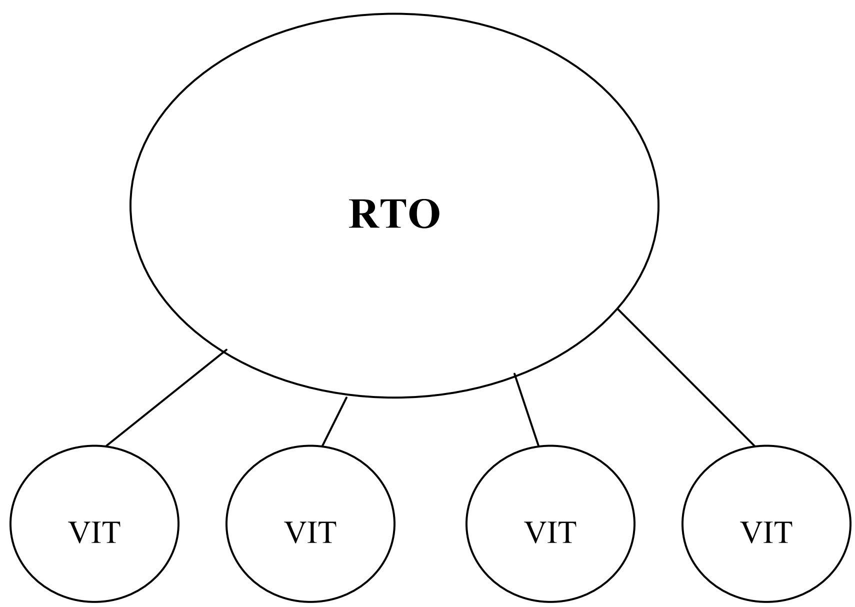
Even for ITCs without sufficiently large footprints, a subset of the metrics may be individually applied (e.g. system availability) through a PBR. Furthermore, it may be possible to engage more than one ITC in a joint PBR mechanism that encompasses the full range of metrics to achieve the desired outcomes. We recognize that a vertically integrated utility could equally participate in a PBR for its footprint; however we would question the enthusiasm with which all such entities would engage! As it may also be difficult to engage a non-profit RTO in a meaningful and effective PBR, having the ability for one or more ITCs to take on performance accountability is a worthwhile pursuit.

The contemplated PBR derived from the described metrics would encompass the breadth of the transmission business functions, from system operation, to regional planning, to timely new construction. Indeed it would be difficult to design a comprehensive PBR under the current split of functions between and RTO and TOs. This is because RTO and TO actions may both contribute to the outcomes.

This suggests a model different from the current one in which RTOs take on significant transmission functions. Rather we suggest that, with the emergence of an independent transmission company sector, the RTO role may be reduced only to that necessary to operate the system in real time, design and administer markets, and monitor/oversee market performance. The ITC sector would be expected to deliver transmission service that would enable reliable and efficient markets, and indeed PBR mechanisms would be designed to encourage this outcome.

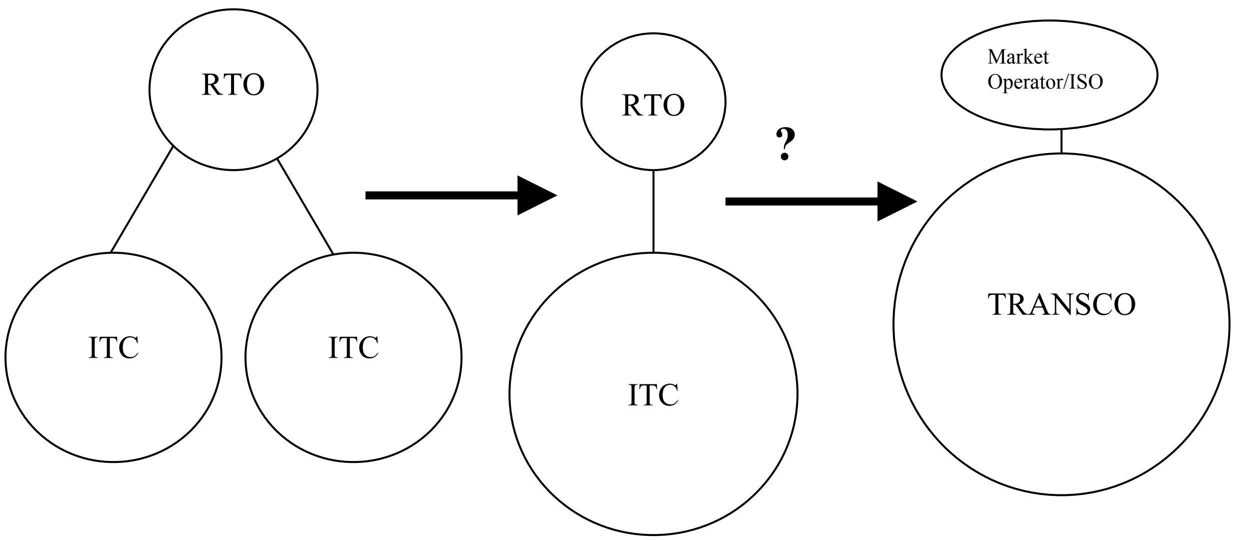
We may illustrate our model options as follows. First we suggest the current RTO model which we call "RTO-Heavy" with vertically integrated transmission –owning utilities. This model has the RTO performing many transmission business functions, with the RTO maturing to undertake more as it becomes able. The participating vertical utilities become largely near-passive owners of transmission. As a result, the RTO-Heavy model has a large non-profit influence, as well as the inability to structure meaningful PBR to effectuate enhanced performance.

Figure 3: RTO-Heavy Model



We propose an alternate model, based on the encouragement and resultant emergence of a robust independent transmission industry segment. We refer to this model as "RTO-light", in that the RTO transmission business functions would be reduced in favor of placing more functionality into properly incentivized ITCs. It is through this model that we suggest that consolidated and independent transmission service functions can facilitate effective PBR regulatory mechanisms in a way that will yield a significant improvement over the status quo. It is possible to envision a time in the future in which the RTO-ITC model evolves into a comprehensive Transco model with combined ownership and system operation of significant contiguous portions of the electric system, with a market operator.

Figure 4: RTO-Light with ITC Model



6.0 Conclusions

We began our discussion with an assessment of the current state of transmission as a business in the US electric power sector. Our assessment has been somewhat somber, but at the same time we have tried to leave the reader with a sense of where an optimistic future might lie. Any sustainable scenario, we have argued, must accommodate the following basic principles:

Alignment and Cost Allocation: There must be a clear and committed alignment between cashflows, needed investments to support the transmission business, and investors.

Metrics: Transparent metrics, based on performance and customer needs, must be in place in order to promote trust and identify opportunities for improvement.

Regulation: Regulation needs to take a long deep breath before introducing new waves of change. Regulation needs most importantly to work on the alignment and metrics issues noted above.

Regional Planning Process: The process of planning for new investments in transmission needs a steadier foundation in cost-benefit analysis for valuing and prioritizing transmission enhancements in the short run. In addition, the structure of governance and decision rights for TOs and other stakeholders in the Regional Transmission Planning Process must be addressed with the needs of customers of the transmission system in mind.

Independent Transmission Sector: A hospitable environment needs to be created to promote larger footprints for for-profit TOs, so that the transmission business can outgrow its current balkanized state and create companies that can be efficient as transmission service providers.

If we can make some progress on the above issues, then Performance-Based Regulation can be aligned with value creation by TOs, the RTO functions can be reduced to the essential ISO functions, and economic and reliability elements of transmission planning can be captured under a more unified and economically meaningful framework of regulated transmission service providers with sufficiently coherent service areas to make sense from a physical point of view. The research challenges in moving to this new vision are obviously significant.

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