REGIONAL TRANSMISSION ORGANIZATIONS

COMMENTS OF THE EDISON ELECTRIC INSTITUTE

David K. Owens
Kenneth P. Linder
Christina C. Forbes
Barbara Hindin
Mathew Morey
Thomas Schimelpfenig
Erin Perrigo
Russell Tucker
Paul McCurley
David Stringfellow
Jay Carriere

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# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>I. Introduction and Executive Summary</td>
<td>1</td>
</tr>
<tr>
<td>II. The Commission’s Voluntary Approach Under Order Nos. 888 and 889 Has Advanced Grid Regionalization and Its Objective — Robust Wholesale Competition — Dramatically: Understanding — and Accommodating — the Reasons Why RTOs Have Not Emerged Is Key to Further Regionalization.</td>
<td>6</td>
</tr>
<tr>
<td>A. The Commission’s Voluntary Approach Has Worked Excellently; Few Advocate a Strong Regulatory Approach.</td>
<td>6</td>
</tr>
<tr>
<td>B. Understanding Why Certain Regions Have Not Rapidly Developed RTOs Is the Key to Future Grid Regionalization.</td>
<td>9</td>
</tr>
<tr>
<td>C. The Commission’s Consultations with State Commissions Under Section 202 (a) of the Federal Power Act Were a Healthy Expansion of Cooperative Federalism and Provides Excellent Guidance for RTO Implementation Efforts.</td>
<td>11</td>
</tr>
<tr>
<td>1. The NOPR Properly Reflects Many of the Concerns of State Regulators.</td>
<td>11</td>
</tr>
<tr>
<td>2. State Commissioner Recommendations Should Help To Guide the Commission’s Next Steps in Regionalization.</td>
<td>12</td>
</tr>
<tr>
<td>D. The Commission’s Proposed Consultations with Regional Stakeholders Will Complement the Commission’s Voluntary, Flexible Approach and Lead to Understanding How Regionalization Can Be Achieved, Where and When Appropriate.</td>
<td>18</td>
</tr>
<tr>
<td>III. RTOs Are Not the Panacea for All Engineering and Economic Issues and Allegations of Undue Discrimination.</td>
<td>19</td>
</tr>
<tr>
<td>IV. Legal Considerations Must Facilitate RTO Formation.</td>
<td>21</td>
</tr>
<tr>
<td>A. EEI Commends the Commission for Proposing a Voluntary, Flexible Approach That Minimizes Legal Concerns.</td>
<td>21</td>
</tr>
<tr>
<td>B. The Commission Should Allow a Ten Percent De Minimis Ceiling and Must Distinguish Between Controlling and Passive Ownership and Permit Unlimited Passive Ownership.</td>
<td>24</td>
</tr>
<tr>
<td>C. Transmission Owners Must Retain Rights Under FPA Section 205.</td>
<td></td>
</tr>
<tr>
<td>D. The Liability of Transmission Owners Must Be Consistent with the Level of Operational Control.</td>
<td></td>
</tr>
</tbody>
</table>
V. RTO Policy Must Be Developed in the Context of an Overall Economic Framework.

A. The Objective of RTOs Should Be To Provide a Foundation for Increasing Economic Efficiency of Transmission and Wholesale Power Markets.

B. Fundamental Principles Offer a Basis for Efficient Regional Transmission Market Policy.

C. Market Design/Architecture Issues Are Complex and Cannot Be Addressed Through a "One-Size-Fits-All" Policy.

VI. Financial and Business Considerations Need to Drive RTO Outcomes.

A. Overview


D. The Complex Financial Issues in Establishing RTOs Dictate a Flexible Timetable.


A. Ratemaking Must Reflect the Changed Role of Transmission.

B. The Commission Should Adopt Sensible, Risk-Adjusted ROE.

C. Transmission Ratemaking and Pricing Policies Should Encourage RTO Formation.


E. The Commission Should Permit Companies to Adopt Transmission Ratemaking Methods that Encourage Efficient Management and Operations.

VIII. RTOs Should Monitor the Services They Provide and the Markets They Operate for Evidence of Design Flaws.


B. It Is Not Essential that the RTO Be Assigned a Formal Role in Monitoring for the Exercise of Market Power.
C. The Commission Should Take a Flexible Approach to Defining the Monitoring Role. 59

D. RTOs Should Have an Internal Market Monitoring Unit to Perform the Day-to-Day Monitoring Tasks, Complemented by Analysis By Qualified, Independent Outside Experts. 60

E. The RTO Tariff May Include RTO Authority to Impose Fines or Sanctions to Ensure Compliance with RTO Rules, But Should Not Attempt to Define or Prosecute Alleged Exercise of Market Power. 61

F. Additional But Limited Authority May Be Granted During the Transition to Restructured Markets. 62

G. Long-Term Reliance on Price Caps and Price Floors as Means to Control the Potential Exercise of Generators' Market Power Interferes with the Efficient Functioning of the Competitive Power Market and Can Reduce Social Welfare. 63

H. RTOs Should Report on Market Monitoring Plans, Activities and Findings to the Commission and May Seek Guidance From It Regarding Changes to Monitoring Plans and Procedures and Recommendations for Changes in Market Designs. 64

IX. Practical Engineering and Reliability Considerations Must Be Reflected in the Commission's RTO Policy. 65

A. The Electric Industry Is Moving Toward New Engineering and Operation Protocols Necessitated By Changes Resulting From Adoption of Order No. 888. 65

B. Form Should Follow Function During Redesign of the Electric Industry. 65

C. The Commission Should Take a Broad, Flexible Position on the Many Different Characteristics and Functions RTOs May Assume as They Develop. 66

D. Significant Investments in New Information Systems and Tools Are Needed to Develop and Implement Market-based Reliability Initiatives. 67

E. Many Complex Issues Regarding Long-Term Transmission Planning and System Reliability in Evolving Competitive Generation Markets Remain Regardless of RTO Formation. 69

F. The Provision of Ancillary Services, OASIS and ATC/TTC Calculations Can Be Accomplished Independently of Formation of an RTO. 72
G. Effective Congestion Management Can Be Accomplished With and Without an RTO.  

X. Accounting Practices Should Reflect the Needs of RTOs.  
A. The Commission's Required Accounting Should Be Updated to Reflect Changes in Regulation and the Industry.  
B. The Commission Should Consider the Impact of Its Actions on the Ability of Transmission Entities to Use SFAS 71. 

XI. Non-Jurisdictional Utilities Need to Be Full Partners in RTOs.  
A. RTO Formation May Be Hampered By Significant Challenges Presented By Non-Jurisdictional Utilities.  
B. The Commission Should Help to Remove Disincentives for Non-Jurisdictional Utility Participation In RTOs.  
C. The Commission Must Assure a Level Playing Field Among RTO Participants.  
E. Public Power Limitations on Joining RTOs Dictate a Flexible Timetable.  

XII. Conclusion.
APPENDICES


C. Patricia Profeta and Michael Schnitzer, NorthBridge Group, Incentive Rates for RTOs: Sound Public Policy.


E. EEI Proposed Incentive and Performance-Based Rate Regulatory Text.


H. William S. Scherman, Esq. and Gerard A. Clark, Esq., Skadden, Arps, Slate, Meagher & Flom, L.L.P., Restrictions Against Passive Ownership Interests or Voting Interests Over One Percent Are Not Necessary to Achieve a Fully Independent RTO.


I. PricewaterhouseCoopers LLC, Accounting-Related Transmission Issues.

Introduction: Why Incentives Matter

In its efforts to foster the development of competitive wholesale markets, the Commission has, from the outset, recognized the importance of transmission access and pricing policy. Its initial efforts were directed toward securing broad access to the transmission grid on a comparable and non-discriminatory basis, under generally standard terms and conditions. Prior to this NOPR, although the Commission encouraged ISO formation and devoted considerable resources to the evaluation of ISO proposals, its general policy has been to deal with transmission operators as they currently exist.

The NOPR signals a significant “sea change” in this regard. The Commission is now saying that open access on a comparable, non-discriminatory basis is not sufficient to achieve the full promise of competitive wholesale markets (and to support competitive retail markets where states are so inclined). Rather, the Commission is now advancing the view that transmission systems should be controlled by independent institutions, RTOs; that the scope of these RTOs should be decidedly larger than current transmission ownership patterns, and that the functions performed by these institutions should be expanded substantially relative to the status quo. Finally, the Commission has expressed its preference that these significant and substantial changes be achieved on a voluntary basis.

Implementing this new vision poses substantial challenges for all market participants, particularly for the current, largely vertically integrated, transmission owners. Yet, as FERC observes in the NOPR, the benefits of quickly achieving this transformation in control, scope and functionality of transmission institutions are potentially enormous.

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1 The authors are Directors of the NorthBridge Group, economic and strategic consultants to companies in the electric and natural gas industries.
As discussed further below, the ultimate success of FERC's voluntary policy initiative, and the speed with which it is achieved, will depend critically on the Commission's willingness to support and approve incentive ratemaking proposals linked to the formation and operation of the RTOs called for in the NOPR.

Support of incentive ratemaking for RTOs would be a natural extension of current Commission policy. In its decisions of late regarding ISO rate structures, the Commission has recognized the importance of reforming transmission pricing. The congestion pricing models approved for ISOs move away from conventional embedded cost ratemaking and are designed to send price signals that enable grid users – buyers and sellers of power – to make efficient decisions about transmission usage and siting of new generation.

As important as these transmission pricing reforms are, they are dependent on the existence of transmission institutions with the independence, scale and functionality necessary to support economic congestion management. A critical, perhaps essential next step then is to provide system operators and transmission owners with incentives to establish such RTOs and to manage, maintain and expand the transmission system efficiently and in a manner that supports robust regional power markets. It is clear that there are three compelling policy arguments that support such incentives, as outlined below.

1) The Commission Should Use Incentive Ratemaking to Encourage RTO Formation

One of the primary policy rationales for incentive rates for RTOs is the recognition that RTOs as envisioned in the NOPR are not just in the business of moving electrons -- they are helping to create competitive wholesale power markets. The broad societal benefits of large scale functional RTOs are addressed eloquently by the Commission itself in the first part of the NOPR.

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2 It should be noted that performance-based ratemaking can be appropriate for vertically integrated utilities that do not join RTOs. This paper, however, focuses on incentive ratemaking for RTOs.
This paper takes no position on the issue of whether the Commission has the authority to mandate RTO formation. It is clear that the Commission's preference is a voluntary route to RTO formation. The problem, however, is that the process of creating an RTO is lengthy, contentious, expensive and risky from a financial perspective. The experiences in ISO formation to date are adequate illustration of the first three points. The time required to establish an ISO is measured in years, and requires a substantial commitment of senior management time, attention and resources. Both the pre- and post-filing periods have been characterized by extensive and often heated debate among numerous parties. And the start up costs - the hardware and software to support complex transmission pricing algorithms and new control systems - have also been substantial – from the tens to hundreds of millions of dollars.

Some have espoused the view that the potential operating efficiencies from consolidation of transmission operations, coupled with a price freeze at current levels, should provide more than adequate financial incentive for RTO formation. Unfortunately, this does not appear to be the case. Efficiency gains from improvements in system operation and maintenance have a relatively small effect on overall returns, due to the capital-intensive nature of the transmission function. Thus, incentives that allow transmission owners to keep a share of operating efficiencies will, on their own, likely be insufficient to induce voluntary RTO formation. Further, the costs of consolidating operations are potentially very large and may have a lengthy payback at best. There may also be substantial financial risks involved. In particular, establishing an RTO that does not penalize transmission owners financially for the formation of an RTO requires:

- Achieving a separation of T&D costs and a sequencing of rate setting which does not result in any trapped costs (meaning costs that cannot be recovered under either state or federally approved rates)

- Earning an ROE on RTO investment that is no lower than the rate earned on those assets under state regulation
- Negotiating compensation, at the wholesale or retail level, for potential lost wheeling revenues
- Realizing recovery of RTO start up costs, even under retail price caps.

Given these realities, many transmission owners have little reason to create RTOs voluntarily. The problem is not that the RTOs contemplated under the NOPR are a bad idea, or will not produce substantial net benefits. The NOPR describes at length the benefits that are expected to be realized, including lower cost generator dispatch as a result of reduced transmission rate pancaking and improved congestion management; better generation siting and investment decisions as a result of improved price signals; and more efficient transmission grid expansion decisions. Rather, the fundamental policy problem is a mismatch between the costs and risks of RTO formation which today are largely borne by utilities and their shareholders, on the one hand, and the real and substantial social benefits that are created by these actions which flow to wholesale market participants.

Most of the many benefits cited in the NOPR have to do with improved efficiency – and hence the potential for lower prices – in the wholesale power market. The beneficiaries of these lower prices are ultimately end use customers, not transmission owners or their shareholders. In the face of this mismatch between costs, risks and benefits, it is appropriate and necessary public policy to provide a financial incentive to transmission owners to create well-designed RTOs by sharing with the owners some of the benefits created by their actions.

Put another way, RTOs that support larger, more efficient power markets will create a form of consumer surplus that – rightfully – will flow largely to market buyers and sellers. The Commission should encourage dynamic efficiency – the development of such markets – by sharing the anticipated consumer surplus with the markets' facilitators, i.e., the transmission owners creating the RTOs. Such benefit sharing would give transmission owners a more balanced cost/benefit opportunity, and increase the interest in participating in the difficult process of establishing an RTO.
To encourage transmission owners to initiate this process, the Commission should explicitly endorse the concept of an incentive for RTO formation in the final rule. The specific mechanisms by which the Commission could provide such an incentive to transmission owners is discussed later in this paper.

2) RTO Rate Structures Should Provide Incentives for Superior Performance

Another policy rationale for incentive structures, and the one most often cited as a rationale for departing from conventional ratemaking, is to provide efficiency incentives by allowing a regulated entity to keep some of the benefits of any performance improvement that it can achieve.\(^3\) Certainly this is a legitimate goal for RTO ratemaking.

As noted earlier, however, an effective RTO incentive rate structure cannot focus solely on RTO operating efficiencies. Such a narrow incentive plan will likely be insufficient to induce voluntary RTO formation and will not address transmission expansion. More importantly, operating efficiency has little to do with the most important role of RTOs -- to support robust competitive power markets. Performance-based rates for RTOs should include some link to their performance of that role.

One way to do this is to tie RTO returns in some fashion to the quality of service they provide to market participants -- reliability, market responsiveness, congestion management performance, efficacy of responding to interconnection requests, etc. There are few, if any, established benchmarks today for such performance although NERC and other groups are starting to establish quality measures. In this nascent area the Commission should expect -- and encourage -- diversity and creativity in proposals for quality of service measures, and should pay particular attention to market participants' views on what constitutes a high quality of service from an RTO.

3) RTO Rate Structures Should Also Facilitate New Investment in the Grid

Another key policy objective for RTO ratemaking should be to provide incentives for the efficient expansion and debottlenecking of the transmission grid. There are many reasons for the relative lack of investment in transmission in recent years – some of them quite sound. However, to the extent that expansion is needed to expand the scope of wholesale markets, the current regulatory and tariff structure is a major factor inhibiting rather than encouraging new investment. Long depreciation schedules, lack of well-defined transmission rights, federal versus state jurisdiction issues, uncertainty about incremental pricing policy or third-party funding of expansion – arguably these all contribute to “gridlock” for transmission investment.

Current transmission pricing policy, which is based on a “use it or lose it” structure for firm service, does not provide a vehicle to expand the system for economic reasons outside of a request for firm transmission, with a source and a sink specified. Nor does it encourage expansion for short-term and economic transactions, i.e., those transactions that under current pricing policies do not come with a long-term commitment to use, and thus pay for, the transmission system.

Of course, it has long been stated Commission policy to encourage efficient expansion of the grid, and Order No. 888 specifies this as one of the ISO principles. But existing cost-of-service ratemaking does not encourage creative debottlenecking or adoption of new technologies, and has not attracted substantial new investment to transmission.

There are several models that attempt to provide such investment incentives through the design of new transmission pricing structures. These have in common one thing – they move away from the concept that the cost of transmission expansion is socialized among all market participants. One model, a version of which is in use in the United Kingdom, makes the grid operator responsible for congestion costs and thus
provides the operator with some financial incentive to fund an expansion itself when doing so is cheaper than paying for redispatch.

A totally different model, locational marginal pricing, relies on locational prices for energy and transmission service to provide a financial incentive for market participants to fund investment in transmission – when and where they deem it economic to do so -- through contractual commitments to the RTO. Parties funding expansions receive tradable financial rights. This is the structure that has been put in place in PJM and has been approved for the New York ISO. A third approach is the zonal pricing model, which combines elements of the first two. The grid operator is responsible for congestion within zones, whereas market participants would be expected to fund investments in congestion relief among zones. A form of this pricing structure is in place in California.

Under yet another approach, sometimes referred to as the Enron model, the grid operator auctions off physical rights to the system. The market value of the rights is established through secondary market transactions, which in turn provide a financial incentive for investment in transmission expansion funded by market participants and/or the grid operator.

The fact is that the ability of these models to call forth more transmission investment is as yet unknown.\textsuperscript{4} Even the models that are designed to rely on market-funded transmission expansions may require a limited backstop provision for funding new investment in the more traditional fashion (\textit{i.e.} rolling it into rates.) In any event, it is important to recognize that merely encouraging investment in the grid will not be sufficient; the transmission rate structures must provide explicit incentives for grid investments, and this should be reflected in the Commission’s final rule.

\textsuperscript{4} The effect on generator siting has been more immediate. Locational marginal pricing in PJM and New York appears to have affected generator siting decisions already. In California, with its zonal pricing model, the ISO has been attempting to influence generator siting decisions in order to hold down intra-zonal congestion.
Mechanisms for RTO Incentives

This paper has identified three policy rationales for RTO incentives: to stimulate RTO formation, to encourage superior performance in supporting large competitive energy markets, and to facilitate grid expansion. These policy objectives can be pursued through different incentive rate mechanisms — there is no one recipe. Not all incentive structures are equally compatible with all forms of RTO — what works for a Transco may not be as effective with an ISO, or vice versa. The Commission’s final rule should provide sufficient flexibility to encourage innovative incentive proposals from all types of RTO proponents.

The typology of incentive rate mechanisms for RTOs is explained in an accompanying paper by Richard Tabors. Dr. Tabors identifies four types of utility incentive structures: price cap, upper/lower bound (on ROE), static benchmarking and dynamic benchmarking. The first two structures are variations on the concept of extending and formalizing regulatory lag, so that utilities have the opportunity to benefit, at least for some time period, from efficiency improvements they achieve on their own — and likewise are penalized for their mistakes.\(^5\) The benchmarking structures are based on a different concept: the adjustment of utility rates or revenues depending upon the utility’s performance against specific quality measures.

As a general matter, the incentive structures identified by Dr. Tabors are most directly applicable to the second of the policy objectives for RTO incentives, encouraging

\(^\text{5}\) See Kahn, p. 48: “Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one. A similar function is served by the Commission’s following the explicit policy of holding permitted profits not to a fixed percentage, but within a range or ‘zone of reasonableness,’ with adjustments in rates permitted or imposed only when returns fall outside that range.”
superior performance by RTOs. The other policy objectives – RTO formation and grid expansion – can be pursued through mechanisms that are compatible with these incentive structures, as described below.

1) Mechanisms to Provide Incentives for Superior RTO Performance

Ongoing performance incentives for RTOs can be provided through any of the four structures outlined by Dr. Tabors. As explained in his paper, general efficiency incentives for RTOs can be provided through a price cap, or a price cap with an upper/lower bound on ROE. Specific performance incentives, targeted to the RTO’s quality of service in specific areas, can be provided through a benchmarking approach – with the RTO’s revenues adjusted depending on performance against a benchmark. The revenues to be adjusted could be from base rates (access charges) or from ancillary charges (uplift).

For instance, a benchmarking approach has been implemented in the U.K. to encourage National Grid to minimize uplift charges from congestion. A “budget” is established for congestion; National Grid can overrecover or underrecover its actual congestion costs, depending on how it performs against its budget. In a different vein, the board of the California ISO has recently promulgated performance measures for its management, including measures for reliability of service and level of responsiveness to market participants. These types of measures could be adopted for a benchmarked rate structure for RTOs.

In addition, benchmarking structures can be combined with price cap structures. For example, a price cap structure with an upper and lower bound on earned ROE could be established. The RTO’s performance on specific quality measures could then be used to raise or lower the upper bound on earned ROE. Thus by providing superior quality of service the RTO would gain an opportunity to earn an enhanced return, but it would have to improve its efficiency to actually realize that return. Viewed another way, the price cap
gives the RTO the incentive to improve its efficiency; the benchmark ensures that it does not do so at the cost of a deterioration in service.

2) Mechanisms to Provide Incentives for RTO Formation

Incentives for RTO formation can be overlaid on any of these structures. The most straightforward approach is to include an “adder” in the allowed ROE when setting rates for transmission assets managed by qualified RTOs – that is, RTOs that meet the standards outlined in the Commission’s final rule. This could be implemented in the context of what would otherwise be a conventional cost-of-service approach to transmission ratemaking for an RTO, or it could be done in conjunction with the incentive rate mechanisms described by Dr. Tabors:

- In a price cap structure, the ROE adder would be used in setting the initial rate level.
- In a upper/lower bound structure (i.e., a bandwidth on earned ROE) the ROE adder could be used in setting an initial rate, or it could be used in setting the upper bound for earned ROE, or both.

Under either of these approaches, the ROE adder would provide an inducement to RTO formation, and the price cap structure would provide an incentive for ongoing operating efficiency. Benchmarking could also be employed in combination with these. The ROE adder would be used at the outset in setting the RTO’s price cap level or ceiling on earned ROE. Later, depending on its performance against specific benchmarks, the RTO’s price cap or ROE ceiling may be adjusted.⁶

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⁶ An ROE adder for RTO formation could itself be viewed as a form of benchmarking. Transmission owners’ revenues are being adjusted – through the adder – based on their performance in facilitating large, competitive power markets. The performance benchmark is the satisfaction of threshold scope and functionality requirements as outlined in the Commission’s final rule on RTOs.
While any proposed ROE adder would be the subject of a detailed RTO filing, some observations about the appropriate magnitude of an adder can be made at this time. As explained earlier, the adder can be viewed as a mechanism for sharing the benefits of RTO creation. In general, policymakers have taken the position that consumers should receive the majority of the benefits created by incentive regulation. Thus, as regards any incentive for RTO formation, the benefits produced by the RTO should be a multiple of the cost of the incentive itself.

This assessment should take into account both the direct societal benefits from large, efficient markets, and the speed with which the benefits can be realized through a voluntary, incentive-based approach to RTOs versus a protracted, potentially litigated approach. Potential benefits include future savings from economic dispatch over a wider area, better congestion management, more vibrant competition within larger trading areas, and better decisions about generator siting. Precise quantification of these future benefits is inherently difficult, because it requires forecasting delivered energy prices with and without an RTO, and should not be required of applicants. However, the benefits are nonetheless real, and potentially quite large, as the Commission has already recognized in the NOPR. Applicants for an RTO incentive should at a minimum delineate the ways in which their RTO will improve the competitive landscape (e.g., reduction in transmission rate pancaking in a region, visible spot market, reduced TLR curtailments) so that the Commission, state regulators, and potential beneficiaries can make an informed judgment about whether the proposed incentive is justified.

In comparison to the potential benefits, the cost of an RTO incentive may well be relatively small. As an illustration, consider the following hypothetical example. For a transmission provider with $1 billion in transmission net plant, a 100 basis point ROE adder would translate into less than $10 million in additional annual revenue requirement.7

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7 100 basis points is 1% of ROE. Assuming a 50/50 equity/debt capital structure, an increase in ROE of 100 basis points for a transmission owner with $1 billion in net plant would translate to $5 million in additional
To estimate the cost of this to ratepayers, assume that the $1 billion in transmission investment serves 10,000 MW of peak load. The resulting rate impact of the adder would be less than a quarter of a mill per kilowatthour of sales (less than $.25 per MWH).\(^8\) If the adder were doubled to 200 basis points, the rate impact would still be less than one half mill per kilowatthour. If such an incentive for RTO formation were proposed, the question for the Commission would be whether approval of the incentive would bring about an RTO sooner than would otherwise be the case, and whether the RTO would be likely to deliver that much and more in savings in delivered energy costs, relative to a world with no RTO.

3) Mechanisms to Provide Incentives for Grid Expansion

The form of incentive for grid expansion is dependent on which of the three earlier described approaches is selected for a particular RTO. Under the approach where the RTO is responsible for congestion, the strength of the incentive will depend on how large a stake the RTO has in managing congestion. The strongest incentive is created when the RTO is responsible for 100 percent of congestion, but this may need to be balanced against financial integrity, reliability and/or excess earnings concerns. Alternatively, the incentive plan could provide for a sharing of congestion costs between the RTO and transmission customers.

Under the locational price model where market participants are responsible for congestion costs and fund transmission expansion through contractual commitments, the important incentive issue from the RTO's perspective is the pricing of the incremental transmission services \((i.e.\) expansions funded by market participants.) Under one incentive plan, the pricing of incremental expansion would be market-determined (assuming the

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\(^8\)The ratio of $1 billion in transmission assets to serve 10,000 MW of peak load is consistent with the ratio in both California and New England. Assuming a 50% load factor, $8.5 million in revenue requirement would translate to $.19/MWH.
RTO could demonstrate that the service was contestable.) A different approach would utilize cost-based pricing, but with a higher allowed ROE. In either case, the pricing should be designed to encourage the RTO to be creative, innovative and efficient in the identification and marketing of grid expansion opportunities to market participants.

**Conclusion**

The Commission’s final rule should explicitly permit incentives for RTO formation, price caps, and benchmarking structures, individually or in combination. It should also require RTO proponents to provide explicit incentives for grid expansion in their proposed tariffs. The rule should be flexible enough to accommodate different incentive structures so long as they meet minimum design standards: (1) the incentive structure must further the public policy goals expressed in the NOPR and in the ISO Principles enumerated in Order 888, (2) it must not result in rate discrimination, and (3) it must be verifiable and include a tracking mechanism where appropriate.

Incentive ratemaking proposals that encourage the creation of RTOs that meet the Commission’s design objectives, that facilitate grid debottlenecking and efficient expansion, and that provide incentives for the efficient and market-responsive operation of the transmission grid, are in the public interest and must be recognized as such in the Commission’s final rule. Indeed, a realistic incentive rate policy will be pivotal to achieving FERC’s RTO goals on a voluntary and timely basis.
Incentive Rates for Transmission Providers:
Alternative PBR Structures

Richard D. Tabor, Ph.D.
Tabors Caramanis & Associates
Cambridge, Massachusetts

The objective of this appendix is to provide a description of a range of performance based ratemaking alternatives that can be considered for application to transmission system owners and/or operators. Four related and increasingly complex alternatives are described and compared. These reflect both ratemaking methods that are commonly used as well as two alternatives that are current in the literature and may now or in the future be specifically applicable to transmission systems. The appendix also contains a matrix of operational characteristics of transmission systems' ownership and operation and a comment as to the application of each of the four ratemaking alternatives.

Background

Performance Based Ratemaking (PBR) encompasses a breadth of alternatives. All of these alternatives derive, however, from the same theoretical departure point, the underlying theory of the duality of production costs which relates the future output and output prices to today's inputs and their prices minus a term that reflects changes in the productivity of the individual factors of production.\(^1\) In algebraic terms this can be stated as:

\[
(1) \quad \frac{p^1 q^0}{p^0 q^0} = \frac{FPI^1}{FPI^0} - X^e
\]

where
- \(p^1 q^0\): the product price at time 1 times the quantity produced at time 0
- \(p^0 q^0\): the product price at time 0 times the quantity produced at time 0
- \(FPI^1/FPI^0\): the ratio of the increase in factor prices between \(t=0\) and \(t=1\) and

• $X^*$ is the measure of increase in productivity.

Stated simply this means that the revenue to be received for the production of any good or service is the price per unit times the quantity. When comparing between two time periods, it is the price times the quantity adjusted for the change in the cost of the individual factors of production. Often the change in cost is simply approximated by the consumer or producer price index. In addition, the change in the price between the two time periods is related to the increase in productivity (the $X^*$ in this equation). This change in productivity occurs through increases in efficiency of provision of the service, through technological advances, etc.

In Performance Based Regulation, the overall objective is to provide the incentives for the operators of the regulated business to improve their productive efficiency. This improvement can come from either capturing the efficiencies that all other operators in the same field have already captured, or from real improvements in productivity. The challenge of PBR is, then, twofold. First a measure must be derived of the potential for the regulated entity to increase its productive efficiency. This requires the separation of the improvements attributable to “catching up with the pack” from those attributable to basic improvements in process efficiencies. Second the regulator must decide on the split of these efficiency gains between the producer (the regulated company) and the consumer. Again, the critical question is what amount of the improvement is attributable to simply catching up and what amount to actual changes in the way products are produced or services provided.

In the case of transmission investment in the US there is an additional challenge and that is for the regulator to decide how to initiate the process. Since we have little, if any, experience in the pricing of transmission as a separable service business involved solely in the delivery of electric power, deciding on the initial price level in the price cap, for instance, requires art as well as science. This issue is made the more challenging by the reality that we have little experience with collecting, organizing or analyzing the information needed to set these rates.

This is not to suggest that PBR is too difficult a process to initiate for a transmission owning and/or operating entity, only that PBR requires consideration of a number of issues that extend beyond those within a standard cost plus required revenue approach. The most notable difference is that PBR acknowledges that there will be future improvements in the way transmission services will be delivered and that these future improvements can be measured and the benefits shared between the transmission provider and the transmission customer. There is no hard and fast rule as to how these are to be shared, only that they need to be.\footnote{Note that this does not exclude the possibility that the sharing will be 100% to one player and 0% to the other.} Transmission customers are and will continue to clamor
for reduced costs. Transmission providers will strive for greater returns for their efforts. This is a healthy tension that, under PBR, leads to lower transmission costs and higher returns.

The discussion below presents four examples of PBRs that have been implemented and/or are described in the literature and are applicable to transmission. It should be noted at the outset that they are all based on equation (1). They reflect increased levels of sophistication in the methods of estimation and the level of information required. At the same time, they provide increasingly fine means of evaluation and rate setting for regulators while providing the transmission provider the incentives needed to improve operating and investment efficiencies.

**Alternative PBR Structures**

1. **Price cap** — This is the most basic of the systems described and reflects most closely equation (1). The regulator sets a maximum level of revenue to the transmission provider per unit of service provided. The unit of service can be defined as either capacity (KW) or energy flow (kWh). This baseline is then increased annually with changes in inflation (RPI or FPI\(^1\) / FPI\(^0\) in equation (1)) and decreased by a proportion that represents the regulators' estimate of an amount of the productivity gain that should be allocated to the user as opposed to the producer.\(^3\)

   The underlying assumption of the econometric analysis of a price cap calculation (that is not based merely on a retail or wholesale price index) is that the values used in estimating equation (1) are not widely spread, i.e., that the sample is relatively homogeneous. As will be see below, this assumption is relaxed in PBR alternatives 3 and 4.

   The price cap PBR formulation has a number of overarching advantages.\(^4\) The most significant is its simplicity, particularly when the factor prices are simply subsumed into an increase in the consumer or producer price index. Setting the "x" value is difficult and subject to intensive negotiation and regulatory debate but once set remains in place for a known block of time. A second advantage, leading to further "light-handed" regulation, is that review periods are evenly spaced and frequently 5 or more years apart.

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\(^3\) This reflects the RPI-x structure that has been in existence for the National Grid in the UK since privatization on April 1, 1990. It also underlies the regulatory structure of water, gas and telecommunications in the United Kingdom.

\(^4\) Many of the advantages of Price Cap PBR, from the perspective of the individual players in the market, are the same in direction if not in magnitude as those for the other three forms of PBR that are being reviewed in this appendix.
The advantage of price cap regulation from the perspective of the transmission provider is that, similar to the other PBR structures, it offers a clear target for improvements and provides a time frame within which to achieve it. The disadvantage is that if the "x" factor has been set to be too great, the transmission provider will lose money for the length of time between the reviews, with the losses increasing significantly toward the end of the period. While the transmission provider has the right to return to the regulator for a readjustment, this right would need to be symmetric and the provider is likely to be less than enthusiastic about the transmission users "changing the rules" during the period between rate reviews.

From the perspective of the transmission user the advantages are much the same as those to the provider -- known and easily forecasted rates for a prespecified time period. The disadvantages for the transmission user are the reverse of those of the provider though with the same caveats. If the provider is receiving too great a share of the benefits, the users would like to recapture some of those between rate reviews. In the case of the user, the transmission rate is not likely to be a cause for bankruptcy or for major concern. All users of the system are facing the same price for the same service, thus maintaining a level playing field among the users. In addition, it is likely that the users received some portion of the forecasted productivity gains during the previous review period. They are benefiting, it is that the actual benefit does not match what they may have expected.

Societal benefits are more difficult to describe a priori because they are the sum of the producer and consumer benefits plus any non-priced externalities. Thus, so long as the transmission provider is not forced into bankruptcy, the combined surplus on the consumer and the producer side is positive. The surplus attributable to improvements in productivity gets shared between those who own a share of the transmission provider and those who consume the product delivered through the transmission system. The benefits may go to different individuals (a question of equity) but they are captured by society as a whole.

Regulators see advantages and disadvantages to the price cap form of PBR. On the positive side it is arguably simple to administer. Rate reviews are relatively infrequent and there is but one factor to be considered, the "x" value. On the other side, however, is the reality that setting initial conditions for the price cap, i.e., the capital asset value of the transmission provider at time zero, is both complex and difficult to adjust at a later date.5 A second difficulty is in the actual setting of the "x" value. Setting the value too high (allocating too much of the "surplus" to the users) may discourage investment by the transmission provider. Setting the value too low (allocating too much to the provider) may adversely

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5 This difficulty was overcome, though not without significant objection, in the U.K. when OFFER readjusted the capital value of NGC downward after NGC shares were sold into the public market.
affect the wholesale bulk power market and future capital investment decisions in generation. Generation and transmission compete as alternatives to supply energy close to the load. The choice of location for new generation capacity will be heavily influenced by the cost of getting the power to market. The higher the transmission cost, the more likely the generator's locational decision will be to locate closer to load and thus lower its expected transmission cost.

2. Upper/lower bound — This second PBR alternative is, in general, a variant on the price cap in which the gains from increases in productivity are shared between the consumer and the producer in an amount proportional to the level of productivity improvement achieved. The regulator evaluates the transmission provider's gross and net revenues periodically. The rate of return or the proportion of the net revenues that the transmission provider is able to retain is collared by an upper and a lower bound. The collar provides both a floor below which the return is fixed (i.e., it cannot be less than some pre-specified level which reflects the required return on equity) and a ceiling above which the return is fixed (i.e., it cannot earn more than a pre-specified level). The manner in which the increase in productivity is shared between the transmission owner and the consumer of the service is open to negotiation. Figure 1 provides a simple alternative for sharing, an 'S' or Logistic curve.

The difference between a bounded method and that of the simple price cap is that with this method the incentives for operational efficiency vary with the level of success shown by the operator -- the "x" factor is not fixed. In this case, as in the case of the simple price cap, the transmission owner has a level of assurance that if it maintains the volume of use on which its rates are based, it will do no worse than see the minimum return. If it is more productive or able to achieve volume sales / flows that are greater, it will achieve a higher return. These are the incentives that are required for efficient operation of the transmission system. Once again, this form of PBR provides for relatively light-handed regulatory oversight after initial conditions have been set.

The upper/lower bound method has most of the advantages and disadvantages of the price cap with the exception of the choice of a single "x" value. The upper and lower bounds create a level of certainty for the transmission provider and the transmission user and provide the regulator with a choice of a range of values and a functional relationship for sharing benefits. As stated above, the transmission provider sees a floor to the level of return achievable. This advantage is likely to be more than offset by the revenue cap that is applied to the provider's maximum return, particularly in the early years when significant gains in productivity through greater efficiencies in operations and investment could be expected. This same fact would make the upper/lower bound an attractive alternative for the transmission user who would expect to benefit from these same productivity gains.
The benefits to the regulator may be significant. The regulator is able to allow the surplus sharing between the user and the provider to vary as a function of the success of the provider in achieving efficiency gains. While market participants may disagree over the boundary values, a range may be more palatable than a single value set under a simple price cap. The benefits to society are equivalent to those under a price cap.

3. **Benchmarking relative to the mean (static)** — The concept of benchmarking is that the performance of any product or service provider can be evaluated on the basis of a comparison of its use of resources and, thereby its cost of production, with all other similar service providers. Benchmarking is more correctly referred to as Data Envelopment Analysis (DEA)\(^6\) because the objective is to define an "envelope" within which all observations lie. It is an extension and expansion of the concept contained in equation (1). Equation (1) and simple price cap regulation subsumes all of the variation in the measure of productivity into a single variable -- the cost per unit of service. In DEA the surface or frontier of the envelope of measured performance attributes reflects the best performance that can be seen in the data set for each of the attributes or variables being measured. The solid, bold line in Figure 2 provides an example of an envelope curve covering the data for the individual observations -- the x's in the figure. As can be seen, the surface of the curve reflects the maximum achievable combination of the two attributes, in this case the number of constrained hours and the cost of the transmission access fee. The frontier, or surface of the envelope, also provides information to regulators and to the sample of transmission providers as to the trade-off between the two measures. Once a transmission provider is on the frontier and assuming, in this case, that the frontier does not shift, then it is possible to show how much of one attribute (constrained hours) must increase to achieve a reduction in the other attribute (access fee).

DEA is a means of expanding equation (1) by additional terms to reflect the individual elements of productivity improvement. In practical terms, the regulator compares a transmission provider's operation of a specific transmission system with the operation of other systems (correcting for specific physical differences) to judge its relative performance.

DEA or benchmarking begins with a definition of the characteristics of performance to be evaluated and a list of the transmission providers to be compared. There are two broad approaches. In the first the measurable attributes are listed and ranked by importance. The mean (average) is calculated for each attribute across the relevant population of providers that includes the transmission provider. The transmission provider is then ranked as being above

or below the mean. In the second approach, the transmission provider is ranked by distance from the boundary of the envelope for each of the measured attributes. So long as the transmission provider is measurably inferior to the mean (or far from the frontier) of all transmission providers the regulator might argue that the provider should receive only a relatively small portion of the benefits of increased productivity with transmission users receiving the larger amount. If the transmission provider is closer to the best, i.e., close to the frontier in Figure 2, the regulator might argue that the transmission provider should earn a significant portion of the increased productivity as an incentive to move closer to the frontier.

The attributes reflect measurable quantities and the anticipated / econometrically estimated changes in those quantities over time. For any two dimensions, the result is a tradeoff or, in other words, a "best practices" frontier. There are several points to emphasize with respect to this frontier:

- The frontier represents the best possible performance that can be achieved given current practices by any comparable transmission provider.

- Any transmission provider that (for these two attributes) diverges from the frontier can improve by moving toward the frontier such that it improves its position on either one or both of the attributes, i.e. is no worse off in terms of either attribute.

As with the price cap, the regulator must decide what portion of the potential productivity gain will go to the transmission provider as opposed to the users of the transmission system. In the example in Figure 2, the increase in productivity of the individual transmission provider being evaluated is any change in the "southwest" direction.

The advantage of DEA or benchmarking from the perspective of a transmission provider is the level of detailed information that it provides as potential guidance in improving productivity. In addition, it provides both an intuitive as well as, potentially an econometric estimation of the trade-off among attributes. The disadvantage is the level of detailed data required which could place additional reporting requirements on the transmission provider.

Transmission users may see the DEA process as one of additional complexity with only minimal return. This form of PBR requires more data and information than is needed for the simple price cap. Achieving and demonstrating improvement in productivity requires monitoring and understanding of the individual attributes. The increased detail requires additional time with potentially little incremental benefit to the users.

The advantage for the regulator of moving from the simpler forms of price cap to the more complex characteristics of a benchmarking or DEA system is in
the ability to fine tune the basis on which productivity gains are shared. The regulator can also differentiate between the attributes that are perceived to be of greater or lesser importance to the efficient operation of the system. The significant disadvantage is the level of sophistication required in data and in the ability successfully to create a comparable sample of transmission entities.

4. **Dynamic Benchmarking** — The fourth example of a PBR structure we have called Dynamic Benchmarking. It is a yet more sophisticated version of DEA. In the progression described herein it is the most difficult to implement but the most logical to describe. This continues the progression from equation (1) by acknowledging that over time the productivity index will change for all of the attributes that were considered of importance in the previous example. Over time the "best practices" frontier itself will improve with changes in technology or labor practices. This means that the transmission provider must see the range of improvement possible not only in terms of achieving today's best, but moving toward where the frontier will be at some point in the future. In simple terms, the surface of the envelope curve will move out over time (the gray envelope boundary in Figure 2).

The goal in dynamic benchmarking is first, as above, to define and measure the present state of the attributes and their relative importance. Second it is necessary to estimate the rate of change in those attributes such that the regulator can set the goals for the transmission owner and the proportional sharing of the increases in productivity based on the future performance, not past or present.

To all of the participants in the transmission market the objectives and the advantages of this method are clear, it is prospective (dynamic) and highly differentiable. The disadvantage is equally clear, it is yet more data intensive. From the perspective of the regulator it provides for a more logical setting of the goals by which the transmission provider's operations are to be measured. These reflect the reality that changes in operating practices and improvements in technology will bring added benefits in productivity.

**Summary of Incentives**

The discussion above has, in general terms, described the advantages and disadvantages of four PBR methods. Table 1 to this appendix provides a detailed evaluation of the relative incentives that each of these four alternative forms of PBR described above provide to the transmission provider. The four PBR methods have a number of characteristics in common in that all four derive from the same theoretical structure of the duality of production cost. It is important to recognize that all PBR methods require that the services being provided and the resultant property rights be clearly defined. There are, in addition to the points made above, a number of differences in the incentives that
each of these four methods provide to the transmission provider. The short discussion below summaries the material provided in Table 1. The numbering system relates directly to the rows in the table.

1. Recovery of capital will be a function of the details of the regulatory rules.
   a) Under Price Cap it is largely the initial base rate that determines the level of capital recovery. The implicit rate of return on capital must be sufficient to assure that there will be private investment. This means that the "x" factor in RPI-x can not be so tight as to discourage the entry of private capital. The assumption of RPI-x is that the "x" factor represents the portion of the improvement in productivity that is allocated to the Transmission User.
   b) The upper and lower bound alternative is similar to price cap but with a variable portion of the benefits of improved productivity going to the transmission provider and transmission user. The assumption is that the lower bound would represent the minimum required level of recovery necessary to continue private investment. The upper bound would provide a far better return.
   c) The static benchmarking alternative bases the return on multiple measures of improved productivity. The level of return is based on a comparison of the transmission provider's performance to that of all other transmission providers (or possibly other similar entities) in the sample. Again, the assumption is that the Transmission Users would share in all productivity benefits.
   d) The dynamic benchmarking is more complex. Like (b) and (c) it provides an incentive to the transmission provider through increased return. The return is based on "best practices" as the goal rather than simply "better than average."

2. Operating Costs in all of the 4 scenarios represent the point at which the incentives are the strongest and are, in all likelihood, the largest. Regardless of how the price of transmission is set (/KW or /kWh) the incentive is to reduce operating costs by as large a margin as possible -- particularly between times of regulatory review.\(^7\) It is critical to note that there are significant differences in the mechanisms by which the 4 scenarios measure efficiency but that in the end the incentives themselves appear are nearly identical. This is the case for two reasons. The first is that the process of maximizing benefits from the incentives is based largely on the time between adjustments in rate cases. The second is because the measure of efficiency benefit are the exogenous variables in the allowable rate of return calculations of scenarios 2, 3 and 4. This means that the "how well you do" in

\(^7\) As an example, in the National Grid Company of the UK, employed labor (on measure of operating costs) was reduced by 31% between 1994 and 1998.
terms of efficiency gains, is likely to directly affect your allowed rate of return on capital.\(^6\)

a) In general, this means that the benefits / incentives are greatest at the front end of the transition and diminish as the more obvious sources of savings are captured.

b) Presumably it is early in the transition when the economically efficient mergers of transmission providers takes place.

c) Other management actions that provide significant benefit at this stage are shifting from internal to externally provided services. Line maintenance, right-of-way maintenance, billing, etc. all represent areas where there are known economies of scale (and probably only limited economies of scope even though it has been the assumed economies of scope that have held these functions together in the past).

d) There are questions in all 4 PBR methods about how the benefits associated with greater efficiencies in operations will be extended to the transmission users between periods of regulatory review. Experience with price cap type of regulation has been that regulatory review, while different from the traditional US rate of return reviews, takes on much the same flavor in terms of the transmission provider arguing poverty and the TU and regulator arguing wealth. After the review, the transmission provider charges into cost cutting and for periods of transition generally does well.

Based on these points, the general conclusion is that most of the benefits from any kind of incentive rate structure are likely to be first in the transition benefits and second in terms of operational efficiency. As stated above, the fact that the operational efficiency measures are generally those used to evaluate the amount of return on capital that the transmission provider should earn, these two work in the same direction and in sequence. First there is an incentive to reduce costs (and keep the difference by and large) then because the transmission provider did well in reducing costs (improving efficiency of operation) the provider receives a better underlying rate of return.

3. and 4. (in Table 1) Capacity Expansion and Interconnection incentives are relatively small in all 4 PBR methods. The most significant variable is whether the basis for the price cap is /KW or /kWh. If the basis for earnings is /KW then there is a direct incentive to increase the connected KW so long as the revenues exceed the other costs born by the transmission provider. There are serious trade-offs between the willingness of the transmission provider to capture the benefits of increased connections and the costs that it may incur if it is responsible for congestion management and under a price cap.

Other considerations with regard to expansion and interconnection are:

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\(^6\) This effect is seen less under a price cap, but even there it is seen in terms of how the regulator handles the "x" value. 
a) Is the transmission provider the only supplier (finance and construct) of expanded capacity?
b) Is the transmission provider the only decision maker and/or constructor of interconnections?
c) Does the new capital addition automatically increase the asset base of the transmission provider? If this is the case there are incentives for the transmission provider to build and interconnect. This can be to the transmission provider's advantage if the answers to both (a) and (b) are yes.
d) The conditions under which the incentives for expansion and interconnection are negative are both the reverse of (c) and also those conditions in which the transmission provider is more of a strict operator and less of an owner/operator. If this is combined with a condition in which the transmission provider does not have any economic responsibility for congestion (can simply use curtailment), then there will be few incentives for the transmission provider to do other than maintain reliability on the system. It will take few if any risks associated with investment.

5. Creating and being able to benefit from management of congestion costs is the most challenging of those evaluated largely because it has the potential for being a significant profit center for the transmission provider. One method of handling of congestion on an incentive basis appears to work for any of the 4 scenarios (see (b) below). The other method appears to work best under a price cap type of structure though will function under some specific means of structuring the benchmarking scenarios.

a) The transmission provider may have full responsibility for congestion and for investment. This is essentially the UK model at the present time. In the UK the price cap (though divided into individual elements) covers both the capital and the operating elements of the transmission system. This means that the transmission provider trade-off (minimizes total cost) between paying for the operational costs of congestion (redispach call contracts) and the construction of new facilities to remove the points of congestion.

b) Beginning from a "physical rights" model for congestion in which the transmission provider auctions off transmission rights across potentially constrained interfaces. These represent the ability of the system to deliver "99.9%" of the time. Owners of the rights from the primary market can then sell/trade these rights in a secondary market. In addition to this physical market, the transmission provider (through development of capacity call contracts) or other potential generator redispach pairs can offer to provide financially firm delivery paths for transmission users. This is, then, a fully competitive market in redispach in which the transmission provider is a legitimate player. Note that this would not (in all likelihood) and need not be a regulated market.
Congestion management is a somewhat unique function. It can be:

- the total responsibility of the transmission provider but with no economic incentives (the PJM model)
- the total responsibility of the transmission provider where the transmission provider has the incentives for minimizing total costs and is at risk for doing so (the UK model)
- the opportunity of a number of financial participants in an unregulated market that provides financially firm transmission services. (transmission rights model)

6. Providing financial incentives for the transmission providers to minimize losses on the system is similar in some ways to the incentives for congestion. Losses account, in general, for a far higher cost than does congestion yet its dramatically non-linear function seemingly has kept regulators from tackling this as an economically valuable residual of the system. Providing incentives for reduction of losses is not trivial, however. The transmission provider has the ability to reduce losses through increased line capacity. Others (generators) have the ability to reduce losses by locating closer to the load. Who gets the benefits? Are these two competitive?

To provide an incentive to the transmission provider to reduce losses requires that the transmission provider assume the physical and financial risk of delivery of all contracted energy. To do so might allow for minimization of the wires / losses cost but without other tariff structures in place (some form of locational pricing associated with connection rather than flow) it would not be possible to capture any benefits (or costs) of generator location.

7. Ancillary Services can be divided into two categories. Those that the transmission provider alone can provide and those that theoretically can be provided competitively.

a) Incentives for management of costs associated with the required ancillary services are identical in concept to all other operating costs of the transmission provider (see 2 above).

b) The competitive ancillary services providing VAR support and/or balancing and reserves represent opportunities for the transmission provider to receive competitive economic incentives. The issues associated with provision of these services in a competitive market revolve around whether or not the transmission provider has a de facto competitive advantage (market power) over other potential suppliers. The argument can be made that there is no competitive advantage and that the transmission provider should be able to enter these markets and not merely be the supplier of last resort.
Conclusions

There are three principle conclusions from this evaluation of four alternate methods of performance based regulation. These are:

- PBR can serve a valuable role in the restructuring of the electric power industry in that it provides the means to create incentives for the transmission provider to improve the efficiency and productivity of service provided on the transmission grid.
- PBR as applied to transmission service requires continued, serious evaluation.
- PBR and incentive rate structures require clearly defined products and services and with them clearly defined property rights.
- PBR has the potential to be a beneficial tool for the "light-handed" regulation of transmission service.
August 23, 1999

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

In Re: Comments of the Edison Electric Institute — Docket No. RM99-2-000

Dear Secretary Boergers:

Enclosed please find the original and fourteen copies of EEI’s comments on Regional Transmission Organizations in Docket No. RM99-2-000. Also enclosed are three diskettes in Microsoft Word 7.0 format. These comments are also being filed electronically.

Respectfully submitted,

Christina C. Forbes
Director, Federal Commercial
& Regulatory Policy

Enclosures