Unbundling of Transmission: The Operation and Economics of a For-Profit Transmission Company

Richard D. Tabors
Senior Lecturer, Massachusetts Institute of Technology
and
President, Tabors Caramanis & Associates
tabors@mit.edu; tabors@tca-us.com

Abstract
With the unbundling and the restructuring of the electric power industry worldwide, the transmission component of the system has evolved from merely a means of providing shared reliability and seasonal sharing of resources to becoming the commercial highway. This evolution has allowed a series of institutional models of that highway to develop. Three concepts have emerged under an umbrella of Regional Transmission Organizations: the Independent System Operator (ISO); the Independent Scheduling Administrator (ISA); and the Independent Transmission Company (ITC) or TransCo.

This paper provides a comparison of the three concepts. It focuses on the institutional, economic and regulatory aspects of establishing a regional ITC in the context of the United States regulatory environment. The paper also presents a tariff structure that allows the ITC to operate the power system while neither operating nor participating in the energy market.

1. Introduction
Three alternatives for regionally coordinated transmission service providers have been proposed in response to the changing needs of the electric power industry as it moves from a structure of vertically integrated monopolies to one of unbundled competitive enterprises. These three alternatives are generically called Regional Transmission Organizations\(^2\) and are:

- An independent system operator (ISO): A regulated, not-for-profit entity chartered to maintain system reliability and provide coordination and reliability assurance services to the users of the transmission system.
- An independent scheduling administrator (ISA): A supervisory organization responsible for coordination of transmission systems that remain under the direct control of their existing owners.
- An independent transmission company (ITC): A FERC-regulated, for-profit company that operates, administers and owns or leases all of the transmission facilities within a defined region.

Although each of these entities has different configurations and responsibilities, they do share common functional objectives that respond to the needs of today’s increasingly competitive environment. Specifically, these entities create a structure that allows transmission systems:

- to coordinate system utilization in an active commercial market for electricity,
- to coordinate planning and operation of resources needed to maintain reliability,
- to achieve regional economies of scale, and
- to provide transparent investment price signals.

This paper provides a side-by-side comparison of ISOs, ISAs and ITCs by identifying the attributes of each entity and their corresponding advantages and disadvantages. The issues raised by these comparisons have direct policy implications as the Federal Energy Regulatory Commission (FERC) continues to require open-access compliance.

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2. Independent System Operator (ISO)

An ISO is a regulated, not-for-profit entity chartered to maintain system reliability and provide coordination and reliability assurance services to the users of the transmission system. The ISO is only an operator and holds no assets. The ISO board is either a constituent or a disinterested/independent board (i.e., independent of market participants) and its employees are required to be independent of any other entity that participates in the electricity market.

ISOs have a range of flexibility in the services and responsibilities they provide. Currently there are ISOs that provide minimum services while others provide extensive and diversified services. In all cases, the ISO is responsible for system scheduling, VAR support and residual provision of all other ancillary services. On the other hand, ISOs may or may not coordinate a centralized energy market, perform unit commitment, dispatch centrally, or acquire resources necessary to provide transmission constraint mitigation and ancillary services, such as moment-to-moment system balancing, regulation, voltage support and operating reserves needed to maintain reliable system operations.

2.1 Developing and Implementing an ISO

Implementing an ISO usually involves:

• creating a governance structure to design the new system and manage its operations once in place;
• putting in place a region-wide tariff and with it a funding mechanism (fee-for-services or fixed-fee based); and
• developing the software systems and infrastructure needed to perform new scheduling and unit commitment, dispatch, security analysis, metering and settlement.

ISO control areas that derive from pre-existing tight power pools may have organizational and committee structures which carry forward and upon which additional structure is added e.g., new exchanges for trading short-term energy.

All ISOs should have full responsibility for definition of both total transfer capability (TTC) and available transfer capability (ATC) and for implementation and operation of the transmission system OASIS node. In addition, ISOs have been responsible for some type of congestion management.

2.2 Advantages and Disadvantages of ISOs

The principle purpose of ISOs is to bring former tight power pools into compliance with federal open-access requirements. Before open access, tight power pool members jointly planned and operated their transmission system, individual members frequently jointly constructed both generation and transmission and maintained the fully integrated systems and pool members simply agreed to use their facilities jointly. FERC Order No. 888 required tight pools to develop both tariff and governance structures that would afford pool and non-pool users equal access to transmission. While ISOs are helping to usher in fair and competitive markets and bring about increased efficiencies of competition, the conceptualization and implementation of ISOs have been plagued by serious problems, as many observers, in particular the Commissioners of the FERC, have noted.

Many of these problems involve governance. ISO governance structures all have some means of representing market participants’ interests, either on the ISO board itself or in its committees. Non-traditional market participants still complain of domination of decision-making by transmission owners or even ISO staff. ISOs typically have weak or non-existent incentives to be responsive to market needs. Embodying any system of checks and balances is often difficult. For this reason, ISOs have been accused of becoming self-perpetuating bureaucracies, with built-in incentives to block eventual evolution of the industry structure to regional, independent transmission companies.

There have been a number of efforts to form ISOs in areas that did not previously host tight pools. In certain of these cases disagreements among regional utilities as to the size of the ISO have resulted in unusual geographic groupings (e.g., the Midwest ISO). Other problems included: failures to reach consensus on issues such as different levels of transmission investment and the resulting potential for cost shifts (e.g., the MAPP ISO), the design of transmission rights, zonal versus nodal approaches to locational pricing and the level of complexity to be incorporated into ISO operations.

In cases where the ISO operates a centralized exchange for energy and ancillary services (usually called the “power exchange”), alternative energy changes such as the Alternative Power Exchange (APX) argue that the ISO is in competition with them. In addition, generation owners argue that they can commit and dispatch their resources

more efficiently than a central system with bidding rules. Still other participants argue that congestion management should be market-driven rather than handled centrally with “black box” computer models. Even when the power exchange is an entity separate from the ISO, disagreements continue over the question of whether it should be treated like any other market participant or should enjoy a special relationship with the ISO (e.g., the California PX).

Another criticism of ISOs is their tendency to forego market-oriented solutions in favor of complex systems that depend on software programs whose outputs are driven by arbitrary input parameters and often overly simplistic assumptions. The development of these modeling systems has in several cases taken years and cost hundreds of millions of dollars. “Black box” models coupled with a proliferation of nodal prices that are not known until after the fact can have a chilling affect on market liquidity.

3. Independent Scheduling Administrator (ISA)

An ISA is a supervisory organization responsible for coordination of the transmission systems that remain under the direct control of their existing owners. It holds no transmission assets and consequently is independent of existing transmission owners and market participants. It functions to develop and continuously monitor for non-discriminatory operations over which it has supervisory responsibilities and ensures that open-access transmission service is provided to the fullest extent possible. An ISA represents a highly coordinated overlay on the existing multi-control area form of organization characteristic of many parts of the North American power industry.

3.1 Developing and Implementing an ISA

Functions that would be centralized in an ISO are typically dispersed among the following entities under an ISA:

- an independent regional security coordinator (IRSC) which determines real-time operating limits and (if necessary) implements curtailments;
- a control area operator (CAO), or several CAOs, which operates the grid in real time in accordance with schedules established by the ISA, as modified by the IRSC;
- transmission owners who administer transmission prices pursuant to a region-wide tariff, so as to recover their revenue requirement; and
- a regional transmission group (RTG) which facilitates coordinated transmission planning.

However, the ISA itself still maintains many responsibilities including:

- the daily and longer-term calculation of TTC, committed uses and ATC and the development, implementation and oversight of regional transmission access protocols;
- the development and operation of a single OASIS through which all uses of the transmission facilities are scheduled;
- the scheduling in advance of real time and the development of a secure region-wide daily operating plan that is communicated to CAOs for implementation;
- the oversight of CAOs real-time operations;
- the investigation of complaints of the open-access rules, protocols and standards of conduct as well as dispute resolution; and if necessary
- the scheduling or allocation to distribution systems.

3.2 Advantages and Disadvantages of ISAs

ISAs have several advantages over ISOs. Foremost is the ease of transition to an ISA, compared to the difficult organizational requirements of an ISO, from the status quo ante of separately functioning utility control areas. The institutional and systems costs reflect these transitional differences. The economic benefits of reliability sharing are nearly equivalent with either joint dispatch (i.e., a single regional control area) or decentralized dispatch (existing individual utility grid operators maintaining their own control areas) which requires little operational change from current systems. Under either option, the ISA performs region-wide scheduling, security analysis and allocation of transmission capacity, with support in real time by the IRSC. Implementation of the ISA, IRSC and RTG (if one does not already exist) is all that is required -- the hardware, software and staffing needs of each are relatively modest. Although the functions performed by the ISA, IRSC and CAO are not new, unbundling them is viewed as a relatively new concept that, while being considered in some regions, has not yet been implemented anywhere.4

4 ISAs are under development in both Arizona and Nevada. Both Desert STAR and the Pacific Northwest Independent Grid Scheduler proposals are structured as ISAs.
ISAs are also beneficial as they avoid the creation of new, large bureaucracies and provide natural checks and balances on the powers of the institutions that are created. ISAs can focus on facilitating commerce rather than “optimizing” the market. As transmission owners will continue to be regulated in much the same way as they are today, little regulatory change would be required, although a coordinated effort to create a single open-access tariff would be necessary.

As in the ISO model, a region-wide tariff is necessary to rationalize transmission usage throughout the region and avoid rate pancaking. A simple but efficient commercial model for allocating the use of scarce grid resources, the capacity rights tariff (CRT), is particularly well suited for use by an ISA, as it relies more on market mechanisms than on centralized computer models. A region-wide CRT should employ a zonal-pricing model and should provide for firm transmission rights with anti-hoarding features, ex ante price certainty and scheduling rules that solve transmission problems through market mechanisms.

The ISA approach addresses the most important needs of the marketplace: making transmission access and pricing independent of transmission owners who have not divested their merchant functions, elimination of rate pancaking through a region-wide tariff, efficient pricing of and access to scarce grid resources and commercial simplicity. Finally, implementation of an ISA and related institutions is consistent with an eventual evolution to an ISO or to an ITC.

However, both ISO and ISA structures have a major disadvantage in that it is difficult, if not impossible, for either entity to see both the costs and benefits of transmission expansion. As a result, there is a tendency either for redispatch to take the place of what might be more cost-effective investments in system upgrades or expansions or for expansions to be institutionally mandated when redispatch might have been less expensive. Independent transmission companies specifically address this concern.

4. Independent Transmission Company (ITC) or TransCo

An ITC, or a TransCo as it is frequently called, is a regulated, for-profit company that either owns or leases under long-term contracts, all of the transmission facilities within a specific area. An ITC operates as any stock company, in accordance with articles that determine the structure of its board and its corporate responsibilities. The ITC is also the system administrator and operator responsible for the reliability of the overall transmission system. It has primary responsibility for the operational resources required to maintain system reliability including acquisition of capacity requirements for short-term operating reserves as well as for those ancillary services required of it by FERC Orders No. 888 and No. 889. The ITC is responsible for maintaining the OASIS node for the control area(s) in which it operates. Finally, and most critically, the ITC is responsible for and has the incentive to invest in upgraded or new transmission capital stocks.  

The ITC must be in total control of the transmission assets within its geographic area. It can obtain control by acquiring assets directly through a corporate divestiture (such as, a stock split), through a purchase and/or through a facilities lease. Any of these acquisition methods provide the same economic incentives to the ITC but each present unique issues that must be addressed. For example, direct ownership may be the most straightforward but it requires that existing entities agree to spin-off or sell their assets, that the ITC have the funds required to pay for them and that they receive regulatory approval. Another consideration is that the tax consequences of the transfer must minimize the apparent income effects on the selling or splitting company in order to both maintain shareholder equity and to provide for ratepayer benefit. On the other hand, while a leasing arrangement allows for full and complete separation of transmission ownership and transmission operations, it also covers the cost of capital representing a fair return to the shareholders or the ratepayers or both. In addition, a lease only requires that the ITC have sufficient funds in any given year to cover the cost of the lease payments (at a minimum, the cost of operations plus a fair rate of return on investment in the capital asset).

Because the ITC is a monopoly, its rates are subject to regulatory review and approval. Its regulation may be under cost-of-service or rate-of-return (RoR) regulation or performance-based regulation (PBR), both of which offer incentives for efficient operation.

4.1 Development and Implementation of ITCs

It is the task of the ITC management to develop and have approved a range of flexible tariff structures that best

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6 The most visible example of an ITC to date is the National Grid Company, which operates the transmission system serving England and Wales. In the U.S., the members of the Midwest ISO including specifically Northern States Power and Commonwealth Edison, AEP with Virginia Power and FirstEnergy, and Entergy have made at minimum preliminary announcements as to their plans to form ITCs.
match corporate objectives and willingness to accept risk as well as maximize its profit given the ceiling on recoverable revenues set by the regulatory process. For example, the ITC could charge for its services as a function of the capacity of supply and/or demand attached to the system ($/kW), as a function of the throughput of the system ($/kWh) or a combination of the two.

The $/kW system provides both capital and operating efficiency signals to users. It provides less incentive for the ITC to move more energy through the system but is far simpler to implement. In contrast, the $/kWh charging system is more complex, provides effectively the same incentive to the grid user as the $/kW based tariff, and provides additional incentive to the ITC for efficient operations. A further alternative is the use of a tariff that includes elements of both the fixed ($/kW) and the flow ($/kWh) structures. The concern with the hybrid structure is assuring that there is no possibility for so-called “and” pricing - i.e., that a transmission user not be billed twice for a single service, once on average and again on the margin.

Congestion management under the ITC reflects one of its principle strengths. The ITC must internalize the costs of congestion. It does this by holding call contracts on generating and demand assets that it can activate when required at a known strike price. This provides the ITC with the operating flexibility of constraint mitigation. Users of the transmission system have four options:

- purchase capacity rights (CRs) to cross constrained interfaces in an annual auction -- once purchased, the CRs can be traded in a secondary market and the revenue from the primary auction is used to reduce the revenue requirement of the ITC;
- identify and contract for counterflows;
- enter the system as non-firm and either accept interruption when the system is constrained or purchase CRs when a transaction’s economic value to the transmission user exceeds the cost of the CRs in the secondary market; or
- purchase “firmed” CRs from the ITC which are financially (as opposed to physically) firm and are provided by the ITC through its redispatch capability.

For congestion management the ITC has the incentive to auction off as many rights as it is feasible to deliver on a reliable basis. This revenue reduces the transmission service charge to all customers and thereby increases the demand for transmission service relative to distributed generation. The ITC has the incentive to take acceptable risk to financially firm-up additional transmission services as a means of enhancing its own revenues. The price for doing so can never exceed the expected price in the secondary market for CRs. The ITC also has the incentive, between rate review periods, to minimize its cost of operations for constraint mitigation since, this reflects its financial reward for efficient management. Finally, the ITC has the incentive to reduce costs through the trade-off between investment in new transmission and continued redispatch.

### 4.2 Advantages and Disadvantages of ITCs

Implementing an ITC requires considerable institutional change. If an ITC is a desired end state, implementing an ISA in the initial restructuring process should be considered. An ISA-type structure easily could be adapted to accommodate an ITC. Evolving an ISA structure into an ITC would involve spinning off transmission ownership (or leasing it from the existing owners) and combining it with the RTG, ISA, IRSC and CAO functions into a single entity. Moving from a bureaucratically entrenched ISO to an ITC is far more difficult.

An ITC is compatible with the full range of market structure options from mandatory pool to fully bilateral, decentralized markets. In the case of central market structures, however, their function would be completely separate from the ITC and notably different from what it would be as part of an ISO. Notably, the function of a central market working in conjunction with an ITC is primarily financial, whereas under an ISO, the function would be both financial and physical.

Virtually all of the advantages of an ITC come from the fact that it has the incentive to operate the transmission system efficiently and to trade-off between operating costs and investment costs. The ITC can and will take acceptable risks to deliver services to transmission system users. It will invest in new technologies and in the cost-effective expansion of its transmission system.

The disadvantages of an ITC center on the potential difficulties in initiating such systems in the United States as opposed to other nations where they have been implemented. Moving from a single, governmentally controlled utility to a system where one element is an ITC is far simpler than beginning from a system requiring aggregation of multiple individual utility systems into a larger, for-profit entity.

However, the Commissioners of the U.S. FERC have publicly indicated their dissatisfaction with the results of functional unbundling, and expressed interest in seeing proposals for ITCs. This interest has been seen most strongly in both the response to the Entergy Request for
Declaratory Order and in the FERC RTO NOPR. While there is no reason why an ITC would not work anywhere, the level of institutional change required of utilities in forming an ITC is greater in the near term than that required for either an ISO or an ISA.

Because the ITC bears the costs of providing congestion management services, it is in the best (and only) position to make a decision (for which it takes risk) to invest in new facilities. This trade-off between operational costs and new investment is unique to the ITC model. It is explicitly not a characteristic of the standard ISO model. Recall that the objective function of the ISO is to operate the system reliably at its lowest cost. While the ISO may be the only entity that can evaluate the need for new investment, it has no capability to make investments. Further, because the ISO is not a profit-maximizing entity, it has no incentives to optimize trade-offs between operating costs and capital costs. Nor will other single market participants or sets of market participants have these incentives.

The ITC concept is criticized for creating incentives to game the quantity of TTC and ATC available for sale into the system in order to increase the operational costs/prices. While this might be theoretically possible there are both short- and longer-term reasons why this would not be sustainable. The most important is that such actions will readily be identifiable by any regulator and therefore subject to remedial action. Second, the ITC would be working at cross-purposes with its own incentives. Increasing its revenues from congestion will concurrently increase its costs to reduce the congestion.

In summary, the concept of an ITC is an attractive alternative to the development of ISOs and the logical extension of the development of ISAs. However, in order to benefit from an ITC, it is critical that an appropriate tariff structure be put into place. The following section outlines the elements of such a tariff structure.

5. Proposed ITC Tariff Elements

The prior sections of this paper have presented the positive and some negative aspects of ISAs, ISOs and ITCs. ISOs and ISAs require little change or originality in the design of their tariff structures as these are little more than extensions of business as usual. The tariff structure of the ITC, on the other hand, must face a set of significant additional challenges. These include design of systems in which the ITC can make a profit, design of or definition of the right lines between the commercial energy market and the role of the ITC in systems control and the requirements of the ITC to be able to submit to oversight by their customers and by FERC. This section presents an internally consistent tariff structure for an ITC.

The tariff structure proposed for an ITC includes a number of innovative features that not only address those requirements explicitly addressed in Order No. 888 but also encompass the range of pricing and service issues facing an RTO in today’s competitive environments. The main goals of this proposed alternative tariff are twofold:

- to provide customers with the ability to operate successfully in new and competitive wholesale markets; and
- to give the RTO the flexibility it needs to provide services which not only meet the requirements of its customers for reasonable rates but also allow the RTO to earn a reasonable return on a sustained basis.

In addition to these goals, the development of the proposed ITC tariff structure is based on the following three main assumptions which provide the structural basis for the tariff:

- **Customer Choice**: the RTO will provide transmission services to a wide range of customers with diverse service requirements;
- **Accurate Price Signals**: the pricing of services offered must be as accurate as possible; and
- **Reasonable Rates**: the combination of competitive market forces and performance-based ratemaking will ensure reasonable rates and prices for services offered and will be more effective than traditional rate-of-return regulation.

### 5.1 Customer Choice

The RTO, regardless of its structure, will provide transmission services to a wide range of customers with diverse service requirements. These customers will eventually include load serving entities (LSE) serving small retail customers, large retail customers (e.g. industrial), generation owners and electricity marketers. They will have diverse service requirements, reflecting differences in their customer mix, load profile, price elasticity, comfort with price volatility and tolerance for financial risk. As a result, these customers will value a tariff which gives them the ability to choose a portfolio of service contracts which best meets their individual requirements. The proposed ITC tariff structure provides the opportunity to choose such a portfolio.

Under the proposed ITC tariff structure customers will have the ability to choose from a broad menu of service and contracting options. In addition to choosing their desired transmission services, they will be able to choose the quality (e.g. level of reliability), quantity and duration
of those services. Moreover, they will be able to choose between competing providers for several ancillary services. This approach promotes economic efficiency by allowing customers to acquire the portfolio of services that best meets their specific requirements during any given period.

In addition, innovative customer choice features for congestion management are also available under the proposed ITC tariff structure. Customers will be able to acquire basic transmission service separately from firm capacity rights (FCRs). This will enable customers to acquire and to pay for transmission service during periods when the system is not congested separately from transmission rights across constrained interfaces when the system is congested. This distinction, between access and FCRs, also facilitates another innovative customer choice feature -- a menu of options for acquiring service when the system is congested.

Under the proposed ITC tariff structure customers will be able to choose from a range of congestion management options. Customers can develop the portfolio of "congestion management" services which best meets their individual requirements in terms of level of service quality, level of service cost and level of cost certainty. They can develop this portfolio from the following options:

- firm capacity rights (FCRs) acquired from the RTO and/or the secondary market in advance of the day of delivery for periods of up to one year;
- firming service acquired from third party providers and/or the RTO in advance of the day of delivery for periods of one month, one week or one day; and/or
- redispatch acquired from the RTO during the day of delivery.

Under this approach customers can combine one or more of the above services with their basic transmission and ancillary services to acquire transmission services equivalent to either the network or the firm point-to-point services contemplated under the FERCs pro-forma tariff.

Table 1 is a summary of the customer choices available under the proposed ITC tariff structure.

### 5.2 Accurate Price Signals

As described above, the proposed ITC tariff structure accounts for pricing of a wide range of services. In order to facilitate the most efficient customer-choice options, it is critical that accurate price information be readily available to customers. This allows customers to evaluate the services offered and compare them to other resource options available to them such as acquiring electricity via new generation sited closer to their loads or evaluating methods to reduce electricity requirements through load management, efficiency improvements and/or fuel switching. In addition, accurate pricing facilitates competition and in the long run will ensure that the RTO will remain competitive and profitable. Further, from a societal perspective, accurate prices are necessary to ensure appropriate levels of investment in central generation, transmission and distributed generation.

To ensure accurate pricing, the proposed ITC tariff structure incorporates the following innovative pricing features:

- firm capacity rights will be priced at market value, and sold separately from access to the transmission system;\(^7\)
- congestion will be managed via explicit services offered at ex ante market prices;
- charges for basic transmission service will be transaction specific to reflect the use of "zone" facilities for generation, "highway" facilities and "zone" facilities for load; and
- transmission losses will be based on marginal losses.

All of these features will contribute to an accurate and competitive pricing structure for the services offered by the RTO. Table 2 is a summary of the service pricing under the proposed ITC tariff structure.

### 5.3 Reasonable Rates

In addition to the need for accurate pricing, it is also critical that rates be reasonable and just to ensure regulatory approval of the proposed tariff. The combination of competitive market forces and performance-based ratemaking (PBR) will ensure reasonable rates and prices for the various services more effectively than traditional rate-of-return based regulation. This approach will not only achieve the objectives of traditional rate-of-return based regulation, but it will also provide the RTO with the flexibility and the financial incentive to minimize costs over time, price services efficiently and invest in productivity improvements.

The FERC has set forth fundamental policy goals and principles for any incentive rate proposal seeking approval under the just and reasonable standard. The following

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\(^7\) It is important to note that total revenues from the sale of FCRs and basic transmission services will be capped by transmission system revenue requirements. As a result, revenues from periodic sales of FCRs will be used to pay down the cost of basic transmission service thus assuring that there will not be “and” pricing.
major features of the proposed ITC tariff structure exceed the policy goals and requirements set forth by the FERC for incentive rate approval under the just and reasonable standard:

- the RTO will maintain service quality at traditional levels;
- maximum rates would be established in the Section 205 proceeding based on the Commission's traditional just and reasonable standards;
- maximum rates would be capped for 5 years at the levels approved by the Commission in the Section 205 proceeding;
- actual earnings from all services provided by the RTO would be used in the calculation of its actual return on equity (ROE);
- customers paying maximum rates would be credited with a fixed percentage of RTO actual earnings in excess of the maximum allowed ROE;
- shareholders would bear the risk of actual earnings less than the allowed ROE; and
- the RTO would have the flexibility to offer basic transmission service at a discount from maximum rates, on a non-discriminatory basis.

This last feature provides the flexibility needed by the RTO to attract new generation and load customers, as well as to retain existing customers. The RTO would bear all the financial risk of providing service at a discount since its rates are capped between rate cases. On the other hand, customers paying maximum rates have the opportunity to receive a share of incremental earnings resulting from the discounts under the PBR earnings sharing formula.

6. Compliance with Transmission Pricing Principles

In addition to the reasonableness of the proposed ITC tariff pricing structure, it is also consistent with the FERC’s Pricing Policy for Transmission Service and with Order No. 888 which require that:

- a transmission pricing proposal promote efficient expansion of transmission capacity, efficient location of new generation and new load, efficient use of existing transmission facilities (including constrained capacity) and efficient dispatch of existing generating resources;
- comparable charges for comparable services be charged and that customers have certainty of pricing;
- certain customer groups and/or services should not subsidize other groups and/or services and that the transition to a new pricing mechanism should mitigate economic harm;
- transmission prices to be based on the cost of the transmission service provided; and
- there exist ease of use by customers, RTO administration and regulators.

The proposed ITC tariff structure meets all of these requirements. It promotes economic efficiency in several respects. For example, transactions over multiple service areas are served under a single total charge rather than pancaked rates which will facilitate competition, internalize loop flows and allow customers to respond to congestion more economically. The tariff also encourages economically efficient expansion of the system, pricing of FCRs and load service. In addition, the unbundling of charges for distinct services ensures comparability and an emphasis on ex ante pricing provides price certainty. Further, all customers pay comparable prices for comparable services, have price certainty and do not subsidize other customers.

7. Summary

The object of this paper has been to present the proposed institutional and economic structures for the development of Regional Transmission Organizations under the FERC RTO NOPR. The paper has focused on the development of for-profit institutions, specifically independent transmission companies. ITCs are the most efficient means of achieving the goals of an open access market structure for transmission in the United States. If ITCs are allowed to operate under a tariff structure with the elements discussed in this paper, their efficiencies will be evident.

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Table 1: Customer Choices for Transmission, Ancillary & Congestion Management Services

<table>
<thead>
<tr>
<th>Service</th>
<th>Contracting Choices</th>
<th>Provider</th>
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<tbody>
<tr>
<td><strong>Basic Transmission</strong></td>
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<td></td>
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<tr>
<td></td>
<td>Yes</td>
<td>Yes</td>
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<tr>
<td><strong>Ancillary Services</strong></td>
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<td></td>
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<tr>
<td>Scheduling, System Control and Dispatch</td>
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<td>Yes</td>
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<tr>
<td>Reactive Supply and Voltage Control</td>
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<td>Yes</td>
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<tr>
<td>System Restoration</td>
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<td>Yes</td>
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<tr>
<td>Energy Imbalance</td>
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<tr>
<td>Regulation and Frequency Response</td>
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<tr>
<td>Operating Reserve – Spinning</td>
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<tr>
<td>Operating Reserve - Supplemental</td>
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<td><strong>Congestion Management Services</strong></td>
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<tr>
<td>Firm Capacity Rights (FCRs)</td>
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<td>Yes</td>
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<tr>
<td>Firming Service - month ahead</td>
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<td>Yes</td>
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<tr>
<td>Firming Service - week ahead</td>
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<tr>
<td>Firming Service - day ahead</td>
<td>Yes</td>
<td>Yes</td>
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<tr>
<td>Redispatch (real-time)</td>
<td>Yes</td>
<td>No</td>
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Table 2: Service Pricing

<table>
<thead>
<tr>
<th>Service</th>
<th>Price Basis</th>
<th>Price Set</th>
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</thead>
<tbody>
<tr>
<td>Basic transmission</td>
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<td></td>
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<tr>
<td>Demand based</td>
<td>FERC max rate, net embedded</td>
<td>Max reset in rate cases, reduced by PBR credits and FCR credits during transition</td>
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<tr>
<td></td>
<td>costs, can be discounted</td>
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<tr>
<td>Ancillary services</td>
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<tr>
<td>Scheduling et al</td>
<td>FERC max rate</td>
<td>Max reset in rate cases, reduced by PBR credits</td>
</tr>
<tr>
<td>System restoration</td>
<td>FERC max rate</td>
<td>Max reset in rate cases, reduced by PBR credits</td>
</tr>
<tr>
<td>Reactive Supply</td>
<td>FERC max rate</td>
<td>Max reset in rate cases, reduced by PBR credits</td>
</tr>
<tr>
<td>Energy Imbalance</td>
<td>Market price</td>
<td>N/A</td>
</tr>
<tr>
<td>Regulation</td>
<td>Market price</td>
<td>N/A</td>
</tr>
<tr>
<td>Spinning</td>
<td>Market price</td>
<td>N/A</td>
</tr>
<tr>
<td>Supplemental</td>
<td>Market price</td>
<td>N/A</td>
</tr>
<tr>
<td>Congestion Management</td>
<td></td>
<td></td>
</tr>
<tr>
<td>FCRs from RTO (primary)</td>
<td>Price of marginal bidder</td>
<td>Annual auctions</td>
</tr>
<tr>
<td>FCRs from other holders</td>
<td>Market value</td>
<td>N/A</td>
</tr>
<tr>
<td>Firming - month ahead</td>
<td>Market value</td>
<td>Monthly</td>
</tr>
<tr>
<td>Firming - week ahead</td>
<td>Market value</td>
<td>Weekly</td>
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<tr>
<td>Firming - day ahead</td>
<td>Market value</td>
<td>Daily</td>
</tr>
<tr>
<td>Redispatch</td>
<td>Market value</td>
<td>Hourly (ex post)</td>
</tr>
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</table>

9 Prices for all services established ex-ante, except for redispatch. Services in workably competitive markets are in italics.