Principles of Interregional Transmission Expansion

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ABSTRACT

Over the past two decades Federal Energy Regulatory Commission (FERC) policy has sought to promote a robust transmission network in response to the advent of competition in the wholesale marketplace. Its policy has primarily relied on regional transmission organization (RTO) development and merchant transmission to build up the grid and minimize intraregional (seams) problems. These efforts have been largely ineffective to date, however. This article reviews the problems facing interregional transmission projects, and FERC transmission policy, particularly as it relates to interregional transmission expansion. It then suggests principles that the Commission ought to consider to foster such projects. In particular, it suggests that the Commission seek to tie transmission incentives to verifiable measures of reliability improvements and congestion reduction. Further, it outlines a "regional cost recovery tariff" for financing interregional lines. It concludes that FERC policy needs to establish tighter links between performance and incentives, and it should more carefully evaluate the obstacles facing transmission siting.

1. INTRODUCTION

Transmission planning and construction in the United States has historically been done at the level of the vertically-integrated utility (VIU). In this framework, interconnections between utilities served mainly to increase the reliability of the grid. A utility that faced a temporary generation shortfall (*e.g.* due to an unplanned outage of a generating facility) would attempt to import power over an interconnecting line, thus avoiding a blackout or brownout. Given the relatively minor role of interconnecting lines, there has been limited investment in transmission capacity connecting large geographic areas.[1] With the introduction of wholesale and retail competition in the electric power sector, though, transmission interconnections took on a more important role.[2] As entry into wholesale power generation markets increased, the ability of customers to gain access to the transmission services necessary to reach competing suppliers became increasingly important.

Transmission networks thus provide the foundation for wholesale electricity market competition. Without a strong transmission network, electrically isolated areas, or load pockets, abound. Load pocket generators, their market power unchecked by competitors, are free to charge any price the market will bear. Creating this robust transmission network, however, is anything but an easy task. The slow pace of United States transmission expansion has been well documented over the last few years (Hirst and Kirby [2001], Mullen [2003], Hirst [2004]). Recognition of this trend leads to the dual questions of why transmission growth has slowed, and what can be done about it. This paper examines these dual issues as they relate to siting and building interregional transmission projects. Section 2 reviews FERC transmission policies as they relate to transmission expansion, and in particular, interregional transmission. Section 3

[1] See, *e.g.* Joskow, (2003, 2004), McGarvey (2006).

[2] See, *e.g.* Chao *et. al.* , (2005), Woolf (2003).

examines issues especially problematic to the siting and development of interregional transmission lines. Section 4 then discusses remedies specific to interregional transmission projects. Section 5 concludes.

2. FERC TRANSMISSION POLICY

FERC (alternatively, the Commission) has been proactive in the transmission policies it has authored as the industry has shifted toward competition. As far back as the Energy Policy Act of 1992 (EPAct 1992), the Commission mandated that transmission rates were to promote the economically efficient transmission and generation of electricity.[3] The following year, FERC initiated a proceeding addressing the changing needs of transmission owners and users in response to the rising tide of competition in wholesale electricity.[4] In its Transmission Pricing Policy Statement[5] emanating from this proceeding, FERC stated that transmission pricing ought to take place at a regional level, foster economic expansion of transmission capacity, and encourage efficient location of new generators and new load.

With respect to transmission pricing, Order 888[6] directed independent system operators (ISOs) to pursue policies consistent with its Transmission Pricing Policy Statement. Specifically, FERC stated that an ISO's transmission and ancillary services pricing policies

[3] H.R. 776, One Hundred Second Congress of the United States of America, (1992) § 722.

[4] *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act.* IV FERC Stats. & Regs., Notices ¶ 35,024, June 30, 1993.

[5] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, FERC Stats. & Regs. ¶ 31,005 (1994), clarified, 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement).

[6] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 75 FERC ¶ 61,080 (Order 888).

should promote the efficient use of and investment in generation, transmission, and consumption. FERC also encouraged ISOs to conduct studies and coordinate with market participants (including regional transmission groups), and to identify transmission constraints on their systems, loop flow impacts between systems, and other factors that might affect system operation and expansion.

These early orders foreshadowed FERC's preference for locational marginal pricing (LMP)[7] to promote investment in transmission and generation and to manage congestion in real-time markets. In both EPAct 1992 and Order 888, the Commission indicated that transmission rates should promote economically efficient transmission and generation of electricity Further, in Order 888, the Commission acknowledged the need to facilitate interregional energy transport by encouraging bordering regions to work together to identify transmission problems at their seams. Given that the industry was in the early stages of adopting competition, it is no surprise that the early orders were not overly prescriptive with respect to transmission or generation pricing guidelines, as noted by Joskow (2004).

FERC articulated its vision regarding the role of LMP in guiding transmission (and generation) investment decisions in Order 2000.[8] In this order the Commission opined that price signals can provide guidance as to the efficient size and location of new generation and grid expansion. FERC was not comfortable in relying solely on price signals to guide transmission investment, however. The Commission worried that in the absence of a single entity

[7] See Schweppe *et. al.*'s (1988) seminal work on LMP.

[8] Docket No. RM-99-2-000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (Order 2000). The order did not require RTOs to adopt LMP, but it did make LMP the standard by which other congestion management systems would be judged. The order declared that markets that are based on LMP and financial rights for firm transmission service appear to provide a sound framework for efficient congestion management. It also noted that LMP possessed the desirable characteristics of facilitating the creation of financial transmission rights, which enable customers to pay known transmission rates and to hedge against congestion charges

coordinating the actions of market participants, separate transmission investments might work at cross-purposes and possibly even hurt reliability.[9] The order's discourse on transmission expansion concluded with the Commission expressing its preference that RTOs implement a market approach where all transmission customers have access to well-defined transmission rights and efficient price signals that show the consequences of their transmission usage decisions. The Commission felt that within this framework, the decisions of where, when, and how to relieve transmission congestion would be driven by economic considerations. Further, it envisioned that as the market matured, an RTO's role in transmission planning would eventually be limited to extreme circumstances where continuing congestion in an area threatened reliability.[10]

Order 2000 did not explicitly address incentives for to interregional transmission expansion. It did recognize that building interregional lines can be problematic, stating that "[w]here a weak interface is frequently constrained and acts as a barrier to trade, it may be appropriate to place that interface within an RTO region. It may be more difficult to expand a weak interface on the boundary between two regions."[11] The order addressed the problem indirectly, however. In its consideration of the appropriate scope and regional configuration of RTOs, FERC determined that many of the functions an RTO must perform implied that the regional configuration of a proposed RTO should be large in scope.[12] A system of large regional RTOs would have reduced the problem of interregional transmission expansion by minimizing

[9] Order 2000 at 31,164.

[10] *Id.* at 31,165.

[11] *Id.* at 31,084.

[12] *Id*. at 31,082.

the number of RTOs to be interconnected.[13] Given the Commission's stated preference of internalizing weak interfaces, one may conjecture that FERC would have established regional boundaries for RTOs either where healthy interconnections already existed or where interregional trade was historically unimportant.

While Order 2000, together with the subsequent Standard Market Design Notice of Proposed Rulemaking,[14] sought to lead the industry down a path where LMP price signals combined with financial transmission rights (FTRs)[15] to guide transmission expansion decisions, this plan was frustrated by several factors. With respect to this analysis, the central one is the ability, or lack thereof, of a system relying of revenues generated by LMP differences and captured by FTRs to signal and provide the incentives necessary for efficient grid investment.

Such a scheme faces several problems. First, FTR revenues are inherently variable over time. FTRs reward their holders with a revenue stream equal to the difference in LMPs (or nodal prices) at the FTRs' source and sink nodes times the quantity of FTRs held. While nodal price differences will fluctuate naturally with daily changes in load and generation availability, more important is their susceptibility to changing grid configuration and generation additions. The unpredictable shape of the market, due to grid expansions and variations in generation and load over time, can have a huge impact on nodal prices, making a fifty-year investment in a

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[13] Since this network of large regional RTOs has not emerged, FERC instead has approved smaller RTOs, relying on various seams agreements to reduce seams problems (see e.g. *Order Granting RTO Status Subject to Fulfillment of Requirements and Establishing Hearing and Settlement Judge Procedures,* 106 FERC ¶ 61,280, paragraphs 80-97. This seams agreement seeks to encourage interregional transmission investment by coordinating system planning and the assessment of new interconnections using, inter alia, virtual regional dispatch and various seams working groups, (Compliance Filing of the Filing Parties, June 22, 2004, Docket Nos. RT04-2-002 et. al.)

[14] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, RM-01-12-000, 67 Fed. Reg. 55,451, FERC Statutes and Regulations ¶ 32,563 (SMD NOPR).

[15] This concept was developed by Hogan (1992, 1993). See also Bushnell and Stoft (1996a, 1996b, 1997), Chao and Peck (1996), Hogan (1998, 1999, 2000, 2002), and Ruff (2000).

transmission line funded by LMPs capturing nodal prices a risky undertaking.

The incentives inherent in such a plan also pose serious problems. Transmission investments are oftentimes "large" and "lumpy," in that grid investments come in discreet increments and have an impact upon market prices. As Apt and Lave (2003), Blumsack et. al. (2006), and Joskow and Tirole (2005) note, allocation of FTRs to owners of congested transmission lines gives them the incentive to not build new lines (or expand capacity of existing lines), thus keeping existing lines congested and preserving the value of their FTRs.[16]

Not only would owners of existing lines have the incentive to underinvest in the grid if compensated solely by FTRs, but potential transmission developers would have the incentive to under-invest in the grid as well. As per Barmack *et. al.* (2003), a system that rewards transmission investment with FTRs forces transmission investors to consider the impact of their investments on congestion prices the same way that a monopolist in a market considers the impact of his output on the price he receives. As they note, this leads to underinvestment relative to the socially efficient level.[17]

Many economists also argue that locational marginal prices are distorted by market power.[18] Therefore, LMPs do not send correct signals for generation and transmission expansion. Apt and Lave (2003) argue that, more fundamentally, congestion charges based on LMP will not provide the correct price signals for transmission expansion, *even in absence of*

[16] Apt and Lave (2003) thus suggest a two-part tariff in which congestion charges would remain to discourage congestion, but the bulk of payments would be through an energy charge that would provide the incentive for transmission construction and efficient operation.

[17] This result leads Hogan (2003) to conclude that the dividing line between merchant and regulated transmission investment should be whether or not the expansion will have a material impact upon prices. He concludes that absent this dividing line, the end point would be with all investment in transmission, generation, and demand defaulting to regulated investment with mandatory charges levied outside the market mechanism in order to provide subsidies or guarantee revenue collection.

[18] See *e.g.* Barmack *et. al.* (2003), Blumsack *et. al.* (2006), Joskow and Tirole (2005), and Wilson (2002).

market power effects. They state that experience has shown that the line with the highest LMP may not be the tightest constraint in the transmission network. As per Apt and Lave, this means that nodal prices will not always signal where transmission capacity is most needed or the size of the optimal expansion to relieve the constraint.

Regardless of the reasons, merchant transmission investment has not flourished, contrary to FERC's expectations. Thus, in its post-SMD transmission policy, FERC has focused its transmission policies on encouraging RTO participation and independent transmission company (Transco) development. We see this first in Docket PL03-1-000, the Commission's Proposed Pricing Policy.[19] In this proposal, FERC suggested an adder of 50 basis points on the return on equity (ROE) for all transmission facilities whose operational control would be transferred to a Commission-approved RTO. Moreover, the Commission suggested an additional incentive equivalent to 150 basis points applied to the book value of facilities controlled by Transcos that participate in RTOs and meet an independent ownership requirement.[20] The proposal turned to the RTO planning process as the main driver for transmission growth, offering a ROE-based incentive equal to 100 basis points for investment in new transmission facilities that are found appropriate pursuant to an RTO planning process. The incentives FERC offered in its Proposed Pricing Policy were so blunt as to meet substantial resistance.[21]

The Commission fine-tuned its incentive policy in Docket No. RM06-4, "*Promoting*

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[19] Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid, 102 FERC ¶ 61,032 (2003).

[20] 102 FERC ¶ 61,032 at 61,061.

[21] See, *e.g.* Comments of the Public Power Council on the Proposed Pricing Policy for the Transmission Grid (2003), Comments of Louisville Gas and Electric Company/Kentucky Utilities Company (2003), and Comments of the Public Power Association of New Jersey (2003).

Transmission Investment through Pricing Reform" (Order 679).[22] Order 679 encompasses the Commission's response to Congress' initiative in EPAct 2005,[23] which added a new section 219 to the Federal Power Act (FPA). Section 219 requires FERC to establish, by rule, incentive-based rate treatments "for the transmission of electric energy in interstate commerce for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." Section 219 directs the Commission to (1) promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in transmission expansion, improvement, maintenance, and operation, (2) provide a return on equity that attracts transmission investment, (3) encourage the increase of capacity and efficiency of existing transmission facilities, and (4) allow recovery of costs prudently incurred as necessary to comply with mandatory reliability standards issued pursuant to FPA section 215 or related to transmission infrastructure development under FPA section 216.

Order 679 attempts to satisfy the requirements of Congress in EPAct 2005 by amending part 35 of Chapter I, Title 18, *Code of Federal Regulations* by requiring a public utility's request for incentive-based rate treatment to demonstrate that (1) the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion, (2) there is a nexus between the incentive sought and the investment being made, and (3) that the resulting rates are just and reasonable. The order adopts a rebuttable presumption that an applicant has met the requirements of section 219 for transmission projects that (i) result from a regional planning process that considers and evaluates projects for reliability

[22] Final Rule, Docket No. RM-06-4-000, *Promoting Transmission Investment Through Pricing Reform*, 113 FERC ¶ 61,182 (Order 679). FERC issued an order on rehearing in this matter (Order 679-A, 117 FERC ¶ 61,345), but none of the rehearing requests granted have a bearing on the immediate topic.

[23] H.R. 6, One Hundred Ninth Congress of the United States of America (2005) (EPAct 2005

and/or congestion and is found to be acceptable to the Commission, (ii) has received construction approval from an appropriate state commission or state siting authority, or (iii) is located in a National Interest Electric Transmission Corridor. It requires that applicants support their requests for incentive-based rates by making a showing that there is a nexus between the incentives being proposed and the investment being made. Order 679 further allows for single-issue ratemaking,[24] with the expressed purpose of ensuring that new investments are not impeded because of existing system rate issues. The "nexus showing" supplants the requirement of Order No. 2000 that applications for incentives be supported by cost-benefit analysis (CBA).

In Order 679, FERC holds to the principles in its Proposed Pricing Policy. First, Order 679 encourages Transco formation, providing "Transcos with a ROE that both encourages Transco formation and is sufficient to attract investment after the Transco is formed."[25] Second, it promotes RTOs, stating that the Commission will approve, "when justified, requests for ROE-based incentives for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization."[26] So, again in Order 679, the Commission tries to minimize seams problems by encouraging traditional utilities to join RTOs and Transcos, consolidating them into larger control areas, and thus decreasing industry exposure to seams.

Order 679 also explicitly addresses problems associated with interstate transmission projects are problematic. It mentions environmental and land use (Not-In-My-Backyard, or

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24 Single-issue ratemaking is the setting of a rate-of-return on a given project without re-opening the applicant's entire rate bases to review and litigation.

25 Order 679 at ¶ 221.

26 *Id.* at ¶ 326.

NIMBY) concerns associated with obtaining and permitting new rights of way.[27] It notes that interstate projects face substantial risks that ordinary transmission investments do not. Order 679 also acknowledges that such projects are often undertaken only at the election of investors, given that no single entity is required to undertake them.[28] The order concludes that successful development of interregional transmission projects requires (1) flexibility,[29] and (2) rates of return sufficiently high to encourage proactive behavior.[30]

This answer, though, does not address several of the substantial obstacles such projects face. Thus, it would appear doubtful that the order, as currently crafted, will have the desired effect of promoting a robust interregional transmission network.

3. OBSTACLES FACING INTERREGIONAL TRANSMISSION EXPANSION

Hirst (2000) identifies the age-old problem of gaining approval for new transmission lines as perhaps the greatest obstacle to the construction of new transmission. While both intra- and interstate lines face this problem, the problem is amplified for the latter. Meredith /Boli & Associates (1990) state that the transmission siting process is usually more efficient and less time-consuming where a single state agency has siting authority, because a single regulatory authority eliminates the need for a utility to seek separate permits or approvals from numerous agencies at different levels of government.

As one would expect, NIMBY is a primary obstacle to be overcome in siting

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[27] *Id.* at ¶ 24.

[28] *Id.* at ¶ 94.

[29] *Id.* at ¶ 3.

[30] *Id.* at ¶ 56.

transmission lines. Viewing transmission lines as undesirable eyesores, those who live near proposed corridors naturally resist new lines. As Brennan (2006) points out, exurban population growth and the corresponding increase in property values have increased resistance in the last 20 years or so. While Hirst (2000) attributes some of this increase to a decline in a sense of community in Americans, he and Brennan agree that land use concerns are legitimate, and need to be factored into the evaluation of new transmission investments.

Further, cross-state externality issues hamper interstate transmission siting. As Barmack (2003) notes, transmission investment has important distributional impacts. In general, transmission investment effects rent transfers from load pocket generators and generation pocket consumers to load pocket consumers and generation pocket generators. When a project falls entirely within a single state's jurisdiction, the relevant state agency can legitimately weigh the benefits and losses of the various groups involved when making siting decisions. However, interstate lines have no such fallback. Thus, the South naturally opposed SMD, fearing that broader regional markets enabled by it would result in export of the region's cheap power to higher-priced areas. More generally, Morrison (2004) notes that this parochialism is legitimate. Regulators in low-cost states have a statutory obligation to guard the interests of their consumers. They cannot legally support a policy that will lower electricity prices in other states if doing so disadvantages their state's consumers.

As Brennan (2006) notes, interstate lines can also result in positive externalities:

> benefits to having a transmission line in one state are likely to fall across other states with transmission lines on the same grid. Expanding capacity in one state not only increases direct deliveries to into neighboring states, but, because of loop flow, in may also have indirect effects in increasing transmission capacity over lines in other states.[31]

[31] Brennan (2006), p. 45.

In either case, an uninternalized externality exists, and the private (regulated) market will not produce the socially level of output. Both of the examples cited point to underinvestment in transmission by the (in this case, regulated) market.

Cost apportionment is another major hurdle facing interstate/inter-RTO transmission. In both the traditional VIU model and the RTO model of cost recovery, transmission builders recoup their costs by making filings pursuant to section 205 of the Federal Power Act for changes in or relating to the establishment and recovery of their transmission revenue requirements pursuant to their FERC-jurisdictional transmission tariffs.[32] Under both the traditional and project funding methodology, when an investor builds a line connecting its control area/RTO with another region, it adds the cost of the project to its revenue requirement. Thus, customers of the entity building the line end up financing it, while those located outside of the entity's control area are essentially getting a free ride.[33] This problem lead David Gates to comment at the technical conference the Commission held on its transmission pricing policy that:

> Current rate design methodology crumbles when costs remain local and benefits accrue to customers sometimes hundreds or thousands of miles distant. For example, significant new generation is being proposed in Montana, but it is intended to serve communities outside of NorthWestern Energy's control area.[34]

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[32] Order 679 allows for single-issue ratemaking, under which a new transmission project would be kept financially separate from the rest of a utility's transmission rate base.

[33] Because <u>their</u> transmission provider's revenue requirement does not increase with the new line, any increase in transactions on their transmission provider's lines (due to the transaction) will only serve to decrease their transmission provider's rates. The customers will then collectively pay the same amount of money for the increased transactions, so that in aggregate, increased capacity is essentially free.

[34] Transcript of 4/22/05 Technical Conference at FERC regarding Transmission Independence and Investment et al under AD05-5 et al. (FERC 2005). Mr. Gates is Vice-president, Transmission Operations, NorthWestern Energy.

4: PRINCIPLES OF INTERREGIONAL TRANSMISSION EXPANSION

Upon closer examination, we observe that FERC policy on transmission expansion has adopted a "one-size-fits-all" approach up until now. The main problem with this approach is that transmission projects, and in particular, interregional transmission projects face a whole menu of impediments, and it is unrealistic to expect a single policy instrument to address each of these obstacles. For example, offering a Transco incentive rates will encourage it to build projects inside its boundaries, which will presumably benefit its customers alone. It will not give the Transco the incentive to build interconnecting projects, however, unless the incentive rate offered is accompanied by a mechanism that allocates costs on a regional basis. Failure to do so simply inflates the cost of transmission for the Transco's customers. Interregional transmission expansion thus requires policies specially tailored to overcoming the impediments these projects face.

This problem is compounded by the Commission's abandonment of cost-benefit analysis (CBA) in Order 679. By replacing CBA with the weaker nexus test, the Commission is obfuscating the conditions required for a project to receive incentive rates. Order 679 proposes that applicants demonstrate that the facilities for which they seek incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. While an appropriately crafted engineering analysis may demonstrate that facilities ensure reliability, the nexus test cannot demonstrate that facilities built to reduce transmission congestion will actually reduce the cost of delivered power, because the nexus test does not take costs into consideration.

This section thus presents principles the author encourages the Commission to adopt in order to better meet the goals Congress elaborated in section 219 of the FPA. In particular, it promotes ratemaking elements that quantify project benefits. By linking a project's reward to the benefits it provides, these principles attempt to provide a more rational mechanism for project reward than those contained in Order 679. Limiting project rewards to the benefits the project provides is more likely to meet the just and reasonable standard than offering incentive rates that are invariant of actual project benefits.

This section also seeks to improve upon Order 679's methodology for incenting new transmission. This section seeks to address the particularly vexing problems facing interregional transmission expansion more directly than does Order 679, which works almost entirely through second-order effects (greater project return → all siting obstacles overcome). In doing so, it looks not only at the possibility of increasing the supply of transmission, but speculates on the possibility of increasing demand for (reducing resistance to) it as well. The section further suggests possible methods for implementation of these principles, and points out similarities between the principles espoused and elements of RTO Tariffs.[35]

I. Single-Issue Ratemaking

The greatest strength of Order 679 is that it allows for single-issue ratemaking. This is important to interregional projects, as it separates the cost of the project from the rest of the builder's revenue requirement. Keeping the revenues and expenses of the new line separate will reduce opposition from an RTO's transmission customers, because under a rolled-in rate, transmission customers relying mainly on local generation (load-pocket customers) would be subsidizing others' use of the line. Under single-issue ratemaking, an export line may be financed by export revenues, in isolation of all other system revenues.[36] A system operator

[35] At present, PJM only.

[36] On an alternating-current network, this is complicated, because power flows according to Kirchov's laws. Accordingly, electricity provided under a contract between entities in two different locations (regions) will follow different paths with changing system conditions. Therefore, apportioning cost responsibility for a single line according to flow on the line is too complicated to be useful.

could separate out such revenues by using a rough approximation of line flows to apportion export revenue to different owners of interregional lines. The system operator would derive load distribution factors for power exported across interregional lines. Using this data, they would then apportion revenue for import/export transactions to the tie lines across which it would (be expected to) flow.[37] A complication, however, is that the presence of a new line will affect the flow on other interconnecting lines. One possibility for dealing with this eventuality would be to require the system operator to make existing transmission owners whole with respect to the line addition. This requirement would thus credit the new line with the marginal increase in transmission flow it engenders. This issue is problematic as per assuring revenue adequacy of the new line, and is in need of further research.

II. Implement a Regional Pricing Mechanism

Current pricing methodology, which assigns the cost of a project to the footprint of the entity building the project, artificially inflates the cost of transmission facing the builder's transmission customers. Order 679 proposes to further inflate these costs by offering the transmission builder incentive rates for interregional projects, thus further increasing the burden on the transmission builder's customers. Therefore, the Commission should establish a framework for a regional pricing mechanism allocating the revenue requirements associated with new transmission investment on a regional level. Single issue ratemaking allows for just such a framework. Consider a new line connecting RTOs A and B. RTOs A and B would set aside and pay to the transmission builder all of revenue apportioned to the line. The two RTOs would make up the difference between the project's annual revenue requirement and monies collected in this manner by a complementary mechanism.

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[37] To make market participants indifferent to the results of LDF calculations (and thus minimizing protests), the charge for use of the new line would have to be the same as that for existing cross-region transactions.

This pricing mechanism is similar to that already in place between the Midwest ISO and PJM.[38] The Coordinated System Plan between the two RTOs[39] is to identify those projects in one RTO that benefit the other RTO as Cross-Border Allocation Projects. Consistent with applicable OATT provisions, the Coordinated System Plan will designate the portion of project cost for each such project that is to be allocated to each RTO on behalf of its market participants. In accordance with Schedule 12 of the PJM OATT, the transmission builder may choose to either (1) make a fling pursuant to FPA section 205 to revise its network integration transmission service rates (NITS), (2) make a filing pursuant to FPA section 205 to establish a revenue requirement with respect to the transmission project, or (3) establish the revenue requirement through a formula rate in effect applicable to its rates for NITS.

III. Evaluate Additional Benefits Conferred by the New Line

Principles I and II are meant to provide for revenue recovery for the line, without providing any extra incentives for new transmission. Let us start with one of the basic principles established in FPA section 219: the Commission shall establish incentive-based rate treatments for projects which ensure reliability. Order 679 authorizes incentive rates with respect to reliability for projects that (1) result from regional planning processes that evaluate reliability or (2) demonstrate that the facilities for which it seeks incentives ensure reliability.[40] These conditions; however, do not attempt to link the degree of reliability improvement to the incentive sought (other than the vague nexus test).

In order to better match incentives with benefits, therefore, the Commission ought to

[38] Joint Operating Agreement Between the Midwest System Operator , Inc. And PJM Interconnection, L.L.C.

[39] *Id.* at 47-55B

[40] Two conditions for the rebuttable presumption for section 219 approval, that a project be located in a National Interest Electric Transmission Corridor, and that a project has received construction approval form a state commission, most likely are related to reliability as well.

attempt to place a monetary value on reliability improvements associated with the line. Suppose, for example, that a new transmission line prevents outage(s) due to contingencies. It would stand to reason that interruptible rate customers would be willing to pay more for their service if they were not interrupted as often. If such a rate change did occur, then to the extent that the reliability improvement can be attributed to the new line, then the system operator could put in a claim on these increased revenues on the part of the transmission builder. This is the first source for the reliability payment. Second, when a new line prevents a blackout, more power flows across the transmission lines within an RTO's footprint than would have otherwise. This increase in transmission usage increases transmission revenue generated, *ceteris paribus*. The change will, on average, increase transmission revenue generated beyond the aggregate revenue requirement of the RTO's participating TOs. Part, if not all, of this additional revenue could then be rewarded to the line builder for increasing reliability, and thus throughput, of the system.[41]

A third component of value added by the new line is the reduction in redispatch costs the line enables, as noted by Leautier (2000), among others. Further work is necessary to convert this concept into a revenue stream for interregional transmission, since it is not analogous to FTR revenues (see especially Barmack *et. al.*(2003)).

Assuming energy bids approximate marginal generation costs, the RTOs in question would be able to calculate redispatch savings attributable to the new line. Paying the transmission builder solely out of FTR revenues is problematic, because of the perverse

[41] As has been pointed out in various proceedings, the electricity industry is fluid, and transmission and generation additions and retirements will eventually affect the contribution of all transmission lines to reliability. In this case I propose that the RTO offer a fixed reliability adder, equal to the average reliability gain attributable to a line during the years the line is in service preceding a major transmission or generation change. I submit that such a measure would be a better measure of the reliability impacts of a new line than any prospective adder. But see Kirschen and Strbac (2004) for an analysis of the relationship between reliability and line additions.

incentives involved regarding project scaling; therefore, any scheme relying on FTR values would need to incorporate other revenue sources as well. In theory, the reduction in redispatch costs enabled by new transmission will translate into lower energy procurement costs for LSEs. A variable transmission adder, increasing with re-dispatch cost savings, would give transmission builders a good signal as to where to site interregional lines, as long as the RTOs in question could provide a reasonable approximation of this value. How much redispatch cost savings should flow back to LSEs is a question for further research.

At this point we must acknowledge that the exercises listed above are fraught with difficulty. Many would argue that it is incorrect to attempt to calculate the costs and benefits of individual transmission projects, because these costs and benefits accrue to an entire transmission expansion plan, and are virtually impossible to allocate to the individual projects.[42] Indeed, the components of this principle assume that the system operator can examine the interregional line as the marginal project, that is, that the rest of the system is held at the "base case" when evaluating the line's benefits. Thus, these mechanisms are bound to be "dirty." However, to the extent that projects within an RTOs boundaries are financed as part of a system revenue requirement (or, in the case of generation, through the market), this issue is less problematic. The question would seem to be whether a dirty approximation of project benefits is better than the current methodology of Order 679, which relies upon the prowess of interested parties to justify as large of an incentive rate as they are allowed. I would argue that the former is preferable.

IV. A Twist on Financial Transmission Rights

Another desirable pricing component is subscription of financial rights for the new line. This paper envisions a process wherein at a certain point in a project's development (*e.g.* final

[42] See, *e.g*. Nadira *et. al*. (2004).

permits obtained, construction begins, construction ends, in-service date), transmission users provide an up-front payment for right not to be charged for import/export fees for a certain flow of power on the line.[43] There are dual purposes of such an element. The first is to provide a degree of revenue certainty for the transmission provider. In obtaining a long-term subscription to the line, the transmission provider obtains a certain return from the present value of a certain amount of power flow along the line.

The second purpose of such a component is to improve the timing of payments for the transmission provider. As has been remarked,[44] both the long lead time before a transmission project earns a return and the long time period over which a project earns its returns are both disincentives to building transmission. The above mechanism addresses the first problem, in as much as the builder subscribes the rights before the project is completed. It addresses the second, because it allows the builder to collect the present value of the revenue stream up front, as opposed to waiting several years to obtain the payment. Transmission customers may find the subscription valuable both because it provides them with an asset that earns a return, and it provides a hedge against the variable charge related to redispatch cost savings.

V. Ease the Regulatory Burden

Under Order 679, Commission staff is tasked with evaluating the claims of all applicants for incentive-based ROEs that their projects reduce transmission congestion or improve reliability. Such demonstrations require applicants to submit evidence regarding changes in system performance with and without the additional lines. A glaring problem with this

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[43] *e.g.* one might contract for 10 megawatts during peak hours for 10 years. Thus, in exchange for paying a given amount up front, the entity would have the financial right to a flow of 10 MW along the line for the specified period.

[44] Brendan Kirby, (FERC 2005) talks about transmission investment being disadvantaged because of the returns lag associated with transmission. Additionally, Hirst (2000) and Blumsack *et. al*. (2005) point to the long lifetime/recovery period for transmission increasing uncertainty associated with a project.

requirement is that it burdens FERC staff by requiring them to evaluate the evidence presented in each of these cases. Such a requirement tasks Commission staff to run multiple computer programs used by varying applicants for regional grids all across the country on a very limited timeline. Such a process is undoubtedly inefficient, because the RTO has more ready access to the information needed to evaluate such claims than either the FERC or applicants. The Commission would therefore be better advised to rely on RTOs to provide such an analysis. Under such a paradigm, the Commission/staff would mainly be required to verify inputs into an analysis.

A second problematic element of order 679 and 679-A is its requirement that applicants must demonstrate "a nexus" between the incentives sought and the investments being made, that is, they must demonstrate that the incentives are rationally related to the investments being proposed. Order 679-A clarifies that the nexus test "requires an applicant to demonstrate that the incentives being requested are 'tailored to the risks and challenges faced' by the project."[45] A substantial problem associated with this requirement is that unless applicants quantify the "risks and challenges" facing the project, Commission staff will not be able to verify that the incentives sought are in fact tailored to project-specific impediments. Indeed, Order 679 specifically resists such quantification, arguing against requiring applicants to submit cost-benefit analysis because the courts have long recognized that the Commission may consider non-cost factors as well as cost factors in encouraging orderly development of plentiful supplies of electricity and natural gas at reasonable prices.[46] Without such quantification, however, Commission staff is left to speculate as to the relationship between the incentives applicants seek and project-specific

[45] Order 679-A at 21.

[46] Order 679 at 65.

impediments.

VI. Accommodate the Increased Power Flow Inside the RTOs' Boundaries

Along the lines of the above discussion, an important principle of incenting interregional grid expansion is to identify internal transmission upgrades necessary to ensure that the capacity of the transmission line is deliverable. This requires the relevant authority (*e.g.* RTO, ISO, ITC, State Commission) to model internal constraints created by the flow of power on the new line under various conditions through a system impact study. If increasing the deliverable capacity of the new line requires other transmission owners to undertake upgrades, then they would receive a cost-based rate for their upgrade.[47] The key is that the RTO identifies the other transmission upgrades necessary to accommodate increased flows resulting from the new line. The alternative would be to allow the expansion to pre-empt existing flows, and then compensate affected entities. This option is less satisfactory because it may (1) create new (and artificial) load pockets, decreasing the efficiency of the transmission system and creating unnecessary market power concerns; (2) decrease reliability in affected parts of the system; (3) alter the value of existing FTR rights, creating (additional) opposition to grid expansion; and (4) add an unacceptable level of complexity to the process. As per Hogan (1991), "Since the transfer capacity [of the grid] cannot be defined, it cannot be guaranteed easily. As ready examples attest, users who planned for long-distance power sales under one set of loads and operating conditions can find these sales foreclosed later when loop flow from other contract paths clogs

[47] The relevant authority would grant a cost-based rate for the upgrade, because the body undertaking the upgrade is not incurring any risk in this venture (so they should not be paid an incentive rate). Internal upgrades would be financed separately from the grid expansion. The relevant authority would decide which internal grid upgrades to undertake and how to divvy up the cost among customers. This methodology is similar to PJM's Transmission Expansion Charge (PJM Interconnection, L.L.C., FERC Electric Tariff, Sixth Revised Volume No. 1, First Revised Original Sheet No. 270A.01). PJM identifies customers responsible for transmission enhancement charges. PJM's reasoning is that, "in recognition that the benefits to competition, system reliability and/or operational performance of Required Transmission Enhancements may accrue to particular market participants."

the grid."[48] Coordinated expansion planning would help forestall the circumstances Hogan foresaw.

VII. Work with States to Reduce Local Opposition to Lines

While FERC cannot expect to change the tide of public sentiment against transmission lines, it can recognize that increasing land values call for more generous remuneration for land rights. Designation of national interest electric transmission corridors is undoubtedly a needed tool for transmission expansion, because it can remove legal challenges to a project. However, such a maneuver will still be subject to protracted political and legal challenges.[49] The Commission should therefore consider how to signal greater economic benefits for areas subject to such designation. FERC might, for example, introduce a rate adder for remuneration of state and local government entities that work with the federal government in these matters (*e.g.* do not oppose national interest corridor designation). These entities would therefore have to consider not only legal costs that they will incur in opposition to such lines, but also the opportunity cost of lost revenues cooperation generates for them as well. Likewise, the Commission may subsidize the purchase of land[50] used for interstate lines, possibly reducing local opposition as well. Given the legal costs both sides of the standoff will undoubtedly face, as well as the locality's recognition that their efforts may be fruitless, there is clearly room for the Commission and states to work together on a solution to economic NIMBY. Such incentive mechanisms may be the subject of further research.

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[48] Hogan (1991), p. 8

[49] The opposition of Utica, New York to such a designation and the introduction of three bills, H.R. 809, H.R. 829 (*National Interest Electric Corridor Clarification Act*), and H.R. 810 (*Protecting Communities from Power Line Abuse Act*) provide apt examples.

[50] A one-time subsidy would be more economic for all parties than a rate adder, because, presumably, the return that the public (via the Commission) would require for such funds – that is, the interest rate on bonds authorized for the purpose of financing the subsidy – would be lower than the return required by private investors.

5. CONCLUSION

Siting interregional transmission lines is a complicated undertaking, but not prohibitively so. The Commission has put forth laudable effort in this area, but there clearly is room for improvement. This paper thus lays out some basic principles FERC should incorporate in future orders to simplify this task. It advocates a more balanced approach, where the Commission uses a variety of tools to capture the value of new transmission, and thus increase the supply of interregional lines. It also promotes urges the Commission to explore any opportunities to work with localities to reduce resistance to new lines, by means of economic incentives. Such a tact has the potential to be more efficient than fighting local opposition in the courts. This paper emphasizes the special circumstances facing interregional projects, hoping to illustrate that the Commission's present "one-size-fits-all" approach of rate incentives is ill-suited for the particular circumstances of interregional lines.

As its title suggests, this paper is a first attempt at tackling the interregional transmission problem. Many thorny questions remain unsolved. Avenues for future research include tying together the principles elucidated in this paper into a policy proposal for interregional transmission expansion, as well as refining the principles presented and brainstorming additional principles for transmission expansion. More work needs to be done before the potential for reducing opposition to NIMBY may be assessed. And, of course, regional transmission siting presents pressing questions of its own. All these questions, and more, must be solved before the public can be confident that electricity deregulation can have a favorable outcome.

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