Published in The Electricity Journal, December 2009

Public Policy and Private Interests: Why Transmission Planning and Cost-Allocation Methods Continue to Stifle Renewable Energy Policy Goals

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1. Introduction

The need to address global climate change, reduce dependence on foreign energy sources, and lessen consumer exposure to volatile fossil fuel prices has led policy makers to mandate the development of renewable energy resources. Many states have thus established renewable portfolio standards (RPS) that mandate minimum percentages of electricity supply from renewable resources by certain dates, and Congress continues to debate adopting a federal renewable portfolio standard.

However, while adopting RPS policies has stimulated the assessment and development of renewable projects nationwide, the omission of rigorous cost-benefit analysis and discussion of how to best allocate the cost of interconnecting and integrating these resources has created significant financial roadblocks to the construction of the transmission infrastructure necessary to deliver the benefits of these resources.

The fundamental problem is that renewable resources tend to be located in remote areas where there is little existing transmission capacity. Meeting RPS goals will require new transmission capacity to interconnect all of those renewable megawatts. Ironically, some of the states with the most aggressive RPS goals also have in place policies that discourage new transmission development. Moreover, some regional transmission organization (RTO) policies for approving new transmission capacity appear to hinder rather than promote new transmission development.[2] They do this by impeding the development of transmission by anyone but incumbent transmission owners. Finally, owing to the "lumpiness" of new

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[2] In this article, we don't distinguish between RTOs and "independent system operator" (ISOs), because both provide equivalent transmission planning and reliability services.

transmission investments, RTO cost allocation policies can impose huge financial barriers to renewable resource development.

Setting ambitious RPS goals may, on the surface, satisfy the environmental objectives of policymakers and the public, but leaving in place barriers to renewables development while mandating that same development adds up to ineffective public policy. Some of the most serious ramifications of this inconsistency in such policies can be seen in examples from New York, California, and the Midwest. These examples clearly demonstrate that, to remove barriers to renewables development, we must revise public policy.

2. Barriers to New Transmission Development

Transmission capacity provides multiple services. First, by increasing the available portfolio of generating resources that can be used to meet instantaneous demand, it reduces the overall cost of electricity. Second, it increases system reliability by providing additional pathways to meet that same demand, even when certain components—generating plants, transmission facilities, or both—fail unexpectedly. As such, transmission capacity has aspects of a public good.[3] What this means, from a purely market perspective, is that too little transmission capacity will be forthcoming. It also means that transmission capacity beneficiaries have an incentive to "free-ride" on the system. And, it can mean that some transmission owners may benefit by raising "barriers to entry" that increase the difficulty and cost of building new transmission infrastructure that would otherwise provide net benefits to all.

It has long been recognized that transmission infrastructure in the United States is inadequate to meet the growing demands that have been placed on it. To address this inadequacy, the Energy Policy Act of 2005 directed the Federal Energy Regulatory Commission (FERC) to promulgate rules to promote new transmission system investment. These rules took the form of a series of three FERC Orders in 2006 and 2007.[4] Subsequently, FERC issued Orders

[3] See, e.g., J. Lesser and G. Israelivich, "The Capacity Market Enigma," *Public Utilities Fortnightly*, December 2005, 38–42.

[4] Promoting Transmission Investment through Pricing Reform, Order No. 679-B, 119 FERC ¶ 61,062 (April 19, 2007); Promoting Transmission Investment through Pricing Reform, Order No. 679-A, 72 Fed. Reg. 1152 (January 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2007) (Order No. 679-A); Promoting Transmission

679 and 89; these Orders further clarified the incentives for new transmission infrastructure development and the removal of barriers to that development.[5]

FERC has readily offered return incentives for proposed new transmission facilities, but those incentives have not translated into the development of facilities needed to interconnect thousands of megawatts of renewable generation located in remote areas. In fact, in some cases, FERC's granting of incentive returns has reduced the viability of proposed transmission in regional transmission organizations (RTOs) that have strict requirements for cost-benefit justification of new transmission lines: higher allowed returns mean higher revenue requirements, and this increases the cost side of the cost-benefit comparison.

In general, there are two types of transmission projects. The first is needed strictly to meet reliability requirements. Such projects provide economic benefits, but these benefits are not in the form of lower electric prices, which can be measured. Thus, transmission reliability projects are, instead, typically assessed on their relative cost-effectiveness, i.e., whether a given project is the lowest cost way to achieve the required reliability. The second type of transmission project provides economic benefits in the form of lower electric prices. Such projects may also provide reliability benefits, but the primary motivation for them is to interconnect new generating resources to transmission-constrained regions. Examples of such regions include southeastern New York state, the mid-Atlantic states located in PJM East (including Maryland, Delaware, and New Jersey), and numerous cities, such as Los Angeles and San Diego, California.

This second type of transmission project is the most problematic for either independent project development connecting low-cost to high-cost regions or for obtaining the renewable resource development needed to meet RPS requirements. Because of the public good nature of

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Investment through Pricing Reform, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006).

[5] Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities, Order No. 689, 71 Fed. Reg. 69,440 (Dec. 1, 2006), FERC Stats. & Regs. ¶ 31,234 (2006) ("Order No. 689"), order on reh'g, 119 FERC ¶ 61,154 (2007); Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) ("Order No. 890"), order on reh'g, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) ("Order No. 890-A"), order on reh'g and clarification, 123 FERC ¶ 61,299 (2008) ("Order No. 890-B").

transmission, requiring proposed new transmission lines to meet strict cost-benefit tests is self-defeating. For example, consider a proposed transmission line that will deliver lower-cost power from region A to constrained and higher-priced region B. If the line is built, the regional price difference will be eliminated. From an economic standpoint, this is a good thing. Yet, by eliminating the price difference, the economic justification for the transmission line vanishes. No private owner can build such a line, because, once it is built, the equalization of market prices in the two regions eliminates the profitability of the line.

Similarly, transmission lines designed to interconnect regions with significant cost-effective renewable generation potential to load centers are not likely to be justifiable on reliability requirements alone, and they also might not be the most cost-effective way to meet such requirements. For example, rather than increasing transmission capacity into a constrained region, it may be less costly to build new generating capacity in that region. By imposing an RPS requirement while mandating that any new transmission designed to deliver renewable generation meet strict cost-benefit tests, or by requiring renewable developers to pay for all of the capacity additions needed to ensure that their power can be "delivered" to markets, renewable energy development will be thwarted, despite the presence of subsidies, above-market feed-in tariffs, and so forth.[6]

Inherent Conflicts with Existing Transmission Owners

Another troubling issue, related to transmission line approval, is the degree of control and optionality that incumbent transmission owners (TOs) exercise in regional transmission organizations (RTOs) and ISOs. An unintended consequence of the way RTOs were established in response to FERC Order 2000 is that legacy transmission owners are the primary drivers of reliability-based transmission expansion planning.[7] Whereas merchant generation and transmission project developers have historically participated in the definition of transmission network upgrades through the interconnection process, the more general identification of

[6] Although environmental opposition to siting new transmission lines needed to interconnect areas with renewable generation is also a significant issue in meeting RPS requirements, we do not consider such opposition in this article.

[7] Regional Transmission Organizations, 89 FERC ¶ 61,285 (Order 2000), (1999).

transmission system improvements to maintain reliability while meeting load growth has been the province of the TOs, in coordination with the RTO and ISO planning staff. Driven by the need to transform transmission planning into a more transparent and inclusive process in compliance with FERC Order 890, some, but not all, RTOs and ISOs have modified their transmission expansion planning processes to consider transmission development proposals from all market participants. Time will tell if these changes (all endorsed by FERC) will work, but the early evidence indicates that, far from being level, the playing fields are quite tilted in some RTOs/ISOs.

Consider first the New York ISO (NYISO). NYISO´s transmission expansion planning process, known as the "Comprehensive System Planning Process" (CSPP), is based on two complementary, yet distinct, planning processes: a reliability-driven planning process called the "Comprehensive Reliability Planning Process" (CRPP) and a new, FERC-approved, congestion-driven economic planning process called the "Congestion and Resource Integration Study" (CARIS) process.[8]

The CRPP begins by assessing the adequacy of the existing transmission owners' transmission plans to meet the reliability needs of the NYISO system over a ten-year horizon. This is called the "Reliability Needs assessment" (RNA). If, after carrying out the RNA, NYISO identifies any unmet reliability needs, it asks the TOs and any other interested parties to propose regulated solutions to serve as "backstops" in the event that viable market-based solutions cannot be found to meet the identified reliability need.[9] After all of the reliability needs have been addressed, NYISO publishes a Comprehensive Reliability Plan (CRP). If no viable or timely market or regulated solutions are found for a given reliability need, NYISO asks the TOs to develop "Gap Solutions" based on generation, transmission, and DSM to maintain the reliability of the system. The resulting CRP, after it is approved, forms the basis for the subsequent CARIS economic planning process. CARIS comprises a series of three studies of

[8] *N.Y. Independent System Operator, Inc.*, Order on Compliance Filing, 125 FERC ¶ 61,068 (2008) (October 16, 2008).

[9] Backstop regulated solutions and market-based solutions can include generation, transmission, and demand-side resources.

future congestion on the New York bulk power system, including an analysis of the costs and benefits of alternatives to alleviate that congestion.

While well intentioned, NYISO's system planning process fails to recognize several intrinsic barriers to the participation of non-TO developers in the identification and construction of transmission solutions to reliability problems. First, many reliability solutions are "incremental" and difficult to physically separate from the incumbent TO's existing transmission assets. For example, replacing existing transformers with larger ones at an existing substation, reconducturing existing transmission lines, adding additional switchgear to a substation, and so forth are incremental upgrades for which separate ownership would not be cost-effective.

Second, NYISO's reliability planning process only identifies those reliability needs not already addressed by the TOs proposed solutions. Any non-TO transmission projects beyond those required to address reliability needs, or reliability upgrades accelerated for economic reasons, can be justified only on the basis of economic benefits through the CARIS process, or classified as alternate regulated solutions. For the latter to be approved, NYISO requires an 80% supermajority vote of the load serving entities (LSEs) benefitted by a proposed transmission project investment to be rolled into NYISO rates. The problem is that, with the exception of a small number of municipal electric distribution companies, New York's eight legacy transmission owners—Niagara Mohawk, New York State Electric and Gas, New York Power Authority, Orange & Rockland, Central Hudson, and Con Edison and their affiliate companies—own and operate the distribution systems serving most consumers in New York State.

In theory, a supermajority vote protects ratepayers by ensuring that new transmission development benefits those who pay for it.[10] In reality, however, supermajority voting provisions can impose potentially insurmountable barriers to entry for independent

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[10] See, *New York Independent System Operator, Inc.*, Order, 125 FERC ¶ 61,068 (2009). "The supermajority rule provides a useful check to ensure that a project has net benefits by requiring that most of those whom NYISO expects to benefit from a project agree that they actually will benefit." (¶ 130). In its Order on Rehearing, 126 FERC ¶ 61,320 (2009), FERC also stated that, even if such a supermajority voting requirement violated US antitrust laws, "we are not charged with enforcing such laws." (¶ 39). In a still later order, FERC admitted that it did have some antitrust responsibilities. *New York Independent System Operator, Inc.*, Order, 127 FERC ¶ 61,136 (2009).

transmission developers. These barriers serve to squelch economic benefits for those same ratepayers and prevent mandated RPS requirements from being achieved. Moreover, as explained above, under the CARIS process, new economic transmission projects whose costs are to be included in the NYISO tariff must meet a strict cost-benefit test and receive an 80% supermajority vote of the LSEs benefitted by the project.[11] Because it is difficult for many transmission projects even to meet a cost-benefit test where benefits are measured in terms of reductions in wholesale electric prices, the imposition of both a cost-benefit test and an 80% supermajority requirement effectively prevents non-TO transmission projects from being developed.[12]

Furthermore, if one existing transmission owner controls more than 20% of the vote, such a supermajority requirement is tantamount to a "pivotal supplier" condition in a wholesale energy market, i.e., that one owner has an effective monopoly on new transmission development decisions. If that transmission owner determines the new transmission development will adversely affect its profitability, it can effectively restrict development.[13] Or, it could vote against development of the project and then turn around and propose an identical project itself.

The chilling effect of NYISO's adoption of the supermajority vote to approve regulated economic transmission projects has already become manifest. In April 2008, the investors behind the New York Interconnect Project (NYRI), which would have provided a long-recognized need to expand the north-south transmission capacity in New York, withdrew the project's application for a certificate of public convenience and necessity with the NYPSC, in light of the certainty of rejection by New York's incumbent TOs. Yet, according to NYISO itself, additional

[11] *New York Independent System Operator, Inc.*, FERC Electric Tariff, Attachment Y – New York ISO Comprehensive System Planning Process, section 15.6, Sheet No. 960E.

[12] In an October 15, 2009 order denying NYRI's request for rehearing, Commissioner Moeller dissented from the majority, stating, "I believe that the use of a supermajority voting provision will avoid the need to address some very tough issues and will ultimately prevent economic transmission from being developed." *New York Independent System Operator, Inc.*, Order on Rehearing and Motion, 129 FERC ¶ 61,045 (2009).

[13] In its May 19, 2009, Compliance Filing under Docket No. OA08-52-004, NYISO stated that transmission owners voting to reject a new transmission project would have to provide their reasons for rejection within 30 days of their vote.

transmission capacity from upstate New York (UPNY) to southeast New York (SENY) is essential for the economic delivery of renewable energy from UPNY to the SENY electricity markets. [14]

Not only does NYISO lack sufficient long-haul transmission capacity, but until recently its generation interconnection requirements lacked a "deliverability test" obligation for proposed generating resources. A deliverability test ensures that the electricity a new generating resource, such as a wind energy development, can actually be delivered to load centers over the transmission grid. Because NYISO lacked such a requirement, a significant share of existing wind generating capacity in New York is "bottled up." As a result, during parts of the year, existing wind generators must be ramped down because there is insufficient transmission capacity to deliver the energy they produce. And, while NYISO has finally adopted a capacity deliverability requirement for generators that seek to sell installed capacity (ICAP) in the New York capacity regional markets, renewable generators that opt not to do so are not required to pay for System Deliverability Upgrades (SDU). If a renewable developer opts for assured full deliverability, it will be required by NYISO to post security for the full cost share of its "but for" system deliverability upgrades, and it will be assessed and allocated the costs of restoring the transfer capability of facilities and interfaces that may be degraded as the result of the project. Alternatively, the developer may opt for energy only deliverability, in which case it will be

[14] The authors testified on behalf of NYRI before the New York Public Service Commission. See, *New York Regional Interconnect, Inc*., CASE NO. 06-T-0650, Rebuttal Testimony of Jonathan Lesser and J. Nicolas Puga, March 2, 2009. In our testimony, we highlighted the conclusions in a White Paper issued by NYISO regarding transmission expansion. That report, which was cited by Commission Moeller in his dissenting opinion in the Rehearing Oder, stated, "transmission upgrades driven by environmental and public policy reasons are typically not needed to 'keep the lights on' and will likely fail traditional cost-benefit analyses that focus on production costs (LMPs) and congestion/uplift costs. For example, transmission projects needed to develop renewable resources are often uneconomic because the resources are in remote locations, far from load centers and any other significant electric infrastructure. To date, no transmission planning regime (reliability or economic) explicitly includes public policy objectives as essential goals for transmission planning. It is becoming harder to reconcile existing transmission planning frameworks with various public policy mandates being enacted by state (and possibly federal) policymakers." New York Independent System Operator, "Transmission Expansion in New York State," White Paper, November 2008 at 4-2. Available at: http://www.nyiso.com/public/webdocs/documents/white_papers/transmission_11202008.pdf.

uncertain whether the output of the project will always be sold during periods of transmission system peak load. [15]

Cost Allocation and Deliverability Requirements

After an early adoption of ambitious RPS goals, by 2007, California's Independent System Operator (CAISO) found itself overwhelmed by the volume of renewable interconnection requests and insufficient analytical resources to comply with the interconnection study timelines established in its Large Generator Interconnection Process (LGIP).[16] In order to unclog its interconnection queue, CAISO reformed its interconnection study process to analyze geographically proximate groups (so-called clusters) of interconnection requests filed through an annual request submittal window.[17] In a parallel effort, in order to facilitate the interconnection of renewable generation projects away from the transmission system, CAISO successfully instituted a hybrid financing mechanism, known as the Locationally Constrained Resource Interconnection Facilities (LCRIF). In this mechanism, the up-front costs of building interconnection infrastructure for multiple projects are initially born by a transmission owner that is gradually reimbursed as the renewable generators go on-line.[18]

CAISO also redesigned its transmission planning process in compliance with FERC Order 890. The process relies on a "request window," through which market participants can submit transmission, generation, and demand response solutions with economic benefits in order to be considered in the following year's ISO Transmission Plan. As in most RTOs and ISOs, each TO in CAISO develops its own reliability driven transmission plan in order to maintain reliability standards. If a transmission project with economic benefits beyond reliability is identified as

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[15] *New York System Operator, Inc. and New York Transmission Owners*, 126 FERC ¶ 61,046, Order Conditionally Accepting Compliance Filing (Jan. 15, 2009)

[16] On September 15, 2009, Governor Schwarzenegger signed Executive Order S-21-09, which increased the requirement to 33% by 2020 and made the requirement apply to all utilities, including publicly owned municipal utilities that had previously been exempt from the state's RPS.

[17] *California Independent System Operator Corporation*, Order Conditionally Approving Tariff Amendment, 127 FERC ¶ 61,136 (Sept. 26, 2008)

[18] *California Independent System Operator Corporation*, Order Granting Petition for Declaratory Order, 127 FERC ¶ 61,136 (April 19, 2007).

cost-effective by the TO or another party, a project sponsor must submit it for CAISOs consideration under the ISO's transmission planning request window.

CAISO's current transmission planning process has three stages carried out through the year. These culminate in project approval and adoption of the plan during the first three months of the following year.[19] The 2008 request window saw 134 submissions of diverse types of transmission project proposals, including: reliability solutions, economic projects, LCRIF projects,[20] network upgrades for large and small generators, merchant projects, generation alternatives and load interconnections.[21] If no sponsor for economic (or policy compliance) driven transmission projects steps forward, the ISO itself can propose the necessary projects. This may be the case with some of the final project recommendations of California's Renewable Transmission Initiative (RETI) are presented to the CAISO for integration into its 2010 transmission plan. [22]

While California works out the kinks in its new transmission expansion planning processes, the characteristic "lumpiness" of all transmission projects has revealed other barriers to the development of transmission projects to accommodate mandated renewable energy development. The most significant barrier is related to the up-front financing of deliverability network upgrades. The results of Phase 1 of the Transition Cluster in the reformed

[19] California ISO, Business Practice Manual for the Transmission Planning Process Order 890 Compliance Version 4.0, Section 2.0 Overview of the Transmission Planning Process and Annual Transmission Plan, March 30, 2009.

[20] A LCRIF is a trunk transmission line designed to provide interconnection to one or more generating facilities to the transmission grid. For example, it may be more economical to build one substation to connect renewable generation built by multiple developers, rather than separate substations for each. The LCRIF process is designed to foster such developments.

[21] Overview of the 2009 and 2010 ISO Transmission Plans, Joint IEPR/Siting Committee Workshop, May 2009.

[22] The Renewable Energy Transmission Initiative (RETI) is a statewide initiative to help identify the transmission projects needed to accommodate these renewable energy goals, support future energy policy, and facilitate transmission corridor designation and transmission and generation siting and permitting. http://www.energy.ca.gov/reti/ .

CAISO LGIP have saddled a handful of renewable generation projects with enormous up-front costs for deliverability network upgrades. [23]

For example, in one of the clusters analyzed, CAISO estimated necessary network upgrade costs of almost $1.5 billion to ensure deliverability of the generating capacity in the cluster to its likely markets. These costs must be paid by the few projects that opted in their interconnection requests for the Full Capacity (FC) instead of the Energy Only (EO) level of deliverability. The reason is that, in accordance to FERC-approved LGIP rules, all active requests in the cluster must be modeled in the interconnection study, regardless of each individual projects' likelihood of completion.

Further, in spite of substantial increases in the amount of earnest money that must be posted in order to continue through successive stages of the interconnection study process, project developers assigned such a high option value to having a place in the cluster (queue), that numerous projects in the old queue remained, even though they were unlikely to be developed, raising total deliverability requirements and costs. While the Full Capacity interconnection applicants had hoped that some projects would fall out going into Phase 2 of the transition cluster study, thus lowering the required capacity and cost of deliverability network upgrades, the significantly lower security amounts required to participate in Phase 2 of the cluster study, recently submitted to FERC by CAISO, may significantly diminish the expected attrition among interconnection applicants.[24] And, while full capacity interconnection applicants will be eligible for Adequacy Payments, it is doubtful this will be adequate compensation for the financing risk they incurred in securing the up-front financing for such huge network upgrade costs, especially given today's credit-constrained financial markets.

[23] In order to begin studying all interconnection requests in clusters, CAISO chose to continue to continue the old LGIP individual serial study process for those interconnection requests already in the System Impact Study stage (the serial Group), while grouping all other interconnection requests filed by a given date into geographically proximate clusters (the Transition Group). All new requests filed afterwards will not be studied until the next interconnection request window opens.

[24] CAISO has filed a tariff amendment to lower the amount of the next deposit in order to address the needs of small (and often poorly capitalized) renewable generators currently in the Transition Cluster. While substantial, the new lower amount (maximum $7.5 million) will entice developers of marginally viable projects or projects saddled with other uncertainties to pay the ante and stay in the running in hope of capitalizing on their place in the cluster.

It is unclear how these financial constraints will ultimately play out. With CAISO's proposed lower security amounts, most of the affected renewable interconnection applicants have by now posted security in order to proceed into Phase 2 of the cluster study. However, this does not mean that they will be able to finance the required deliverability network upgrade costs assessed by CAISO. We cannot predict the extent to which these financial constraints will have a chilling effect on the market viability of the additional renewable capacity. To remove this hurdle in meeting the state's RPS goals, CAISO should define a new class of renewable deliverability network upgrade projects that would be financed in a manner similar to LCRIF projects, and CAISO should put into this classification some or all of the deliverability network upgrades for renewable energy projects. The RPS-enabling renewable energy deliverability network upgrades thus identified could be proposed by the incumbent TO or by a transmission developer interested in becoming one.[25]

Treating Transmission Investments Needed to Meet RPS Requirements as Public Goods

Many states have determined that RPS requirements are in the best interest of their citizens, even if the resulting cost of electricity paid by those citizens increases as a result. As such, RPS requirements can be thought of as a levy on all electric consumers in order to obtain the benefits of renewable resources. (If renewable resources were less costly than conventional generating resources and provided equivalent service, there would be no need to impose RPS mandates.)

If greater renewable resource development is considered a public good, it makes no economic or policy sense to raise barriers to new transmission development—whether those barriers come as a result of the imposition of strict cost-benefit tests and supermajority vote requirements that effectively prevent new transmission investment by anyone but existing transmission owners or as a result of cost allocation procedures that raise insurmountable

[25] On September 15, 2009, CAISO issued a straw proposal and issue paper that proposes changes to the annual transmission planning process aimed at reducing the uncertainty of transmission for renewable energy projects by "pre-approving" the most cost-effective proposed transmission projects that connect renewable generation that help timely meet the 33% RPS goal. However, the plan does not address the up-front financing of deliverability network upgrades identified by the LGIP cluster study process.

financial hurdles for renewables developers. Rather, the transmission system investments required to enable renewable generators to be constructed and to fully deliver the resulting generation ought to be treated as public goods themselves.

As public goods, those costs are most easily allocated to all electric consumers in relation to their electric consumption.[26] This does not mean there should be no evaluation of the costs and benefits of alternative transmission investments; there should be. For renewable resources, however, those evaluations should determine the least-cost solutions for obtaining the desired amount of renewable resources.

Ideally, one would consider the total cost of renewables development (generation plus interconnection costs). It could be the case that, because of the additional interconnection costs, the "best" renewables areas would be more costly per delivered kWh than regions with less renewable generation (say, a less windy region) but lower interconnection costs. If, however, renewables development and interconnection costs are addressed separately, the next best solution is to determine the least-cost interconnection strategy that will provide full deliverability of the expected renewable resource development in a given region necessary for the RPS goal to be met. Although this approach does not address specific siting and environmental hurdles of renewable resources or transmission infrastructure, it can at least reduce the barriers to renewables development that have been put in place by some RTO/ISOs.

Some RTOs have adopted approaches similar to those we recommend here. For example, the Electric Reliability Council of Texas (ERCOT), through its Competitive Renewable Energy Zone (CREZ) process, is developing a network of high-voltage transmission lines specifically to take advantage of the state's significant renewable generation potential and to allow that generation to be delivered to load centers.

CREZ transmission projects are primarily designed to move electricity generated by renewable energy sources (primarily wind) from the remote parts of Texas (i.e., West Texas and the Texas Panhandle) to the populated areas of Texas (e.g., Austin, Dallas, Houston, and San

[26] Although it may be more economically efficient to allocate costs using Ramsey pricing (i.e., allocating costs in inverse proportion to customers' electric demand elasticity), a more equitable and politically acceptable approach is likely a uniform per-kWh charge.

Antonio). These projects provide the backbone transmission capacity to move renewable generation and will be paid for by all electric consumers in Texas.

The Texas CREZ designation was the culmination of a years-long struggle to find a way to overcome the “chicken-or-egg” problem of: no new wind projects without commitment that transmission will exist and no new transmission without commitment that wind projects will exist to use it. The problem was rooted in long-established regulatory approval principles that were designed to protect the ratepayer: having to demonstrate the need for a project and to adopt a fair method of cost-allocation. “Ignoring” these principles in order to develop renewable resources to meet the RPS and to build the transmission to the load centers was beyond the statutory authority of the PUCT. The Texas Legislature broke the impasse by granting this very authority to the PUCT in 2005. It did so by modifying the Texas Utility Code to instruct the PUCT to consult with ERCOT and other appropriate transmission operators and to then “designate competitive renewable energy zones throughout this state . . . , develop a plan to construct transmission . . . ,” and “consider the level of financial commitment by generators for each [CREZ] in determining whether to designate an area as a [CREZ].”[27] The Legislature also exempted the PUCT from having to consider certain sections of the code that required the PUCT to assess the adequacy of existing service and the need for additional service before issuing a certificate of public convenience and necessity for a transmission project intended to serve a CREZ.[28] The Legislature also addressed the issue of cost recovery assurance by instructing the PUCT to “find that the facilities are used and useful to the utility in providing service . . . and are prudent and includable in the rate base, regardless of the extent of the utility's actual use of the facilities” if the PUCT issued a certificate of convenience and necessity for transmission “. . . to facilitate meeting the goal for generating capacity from renewable energy technologies . . . .”[29, 30] Finally, the Legislature saw no need to change Texas (ERCOT)

[27] Tex. Util. Code §39.904(g)

[28] Tex. Util. Code § 36.053 (d)

[29] *Id*.

[30] *Id.*

transmission cost allocation methodology, whereby transmission costs are recovered through one single postage stamp rate.

Overcoming the statutory hurdles was important, but equally important was the PUCT's role in requiring and verifying the necessary technical and financial wherewithal and commitment of candidate Transmission Service Providers (TSP) prior to being awarded CREZ transmission facilities. The PUCT also requires financial commitments from renewable project developers in the form of a 10% of pro rata share of estimated CREZ transmission costs, which can be forfeited if developer fails to meet project energization deadlines. In summary, the CREZ process shifts the initial investment onus away from renewable developers, while promoting the entry of several well-capitalized new transmission service providers. Moreover, the CREZ process, while still requiring significant financial commitment from the generation developers, avoids saddling them with all associated deliverability network upgrades. In this aspect, the CREZ process differs in a good way from the CAISO interconnection process.

Complications Arising From Multistate RTOs

For states within multistate RTOs, the allocation process is more complicated, for at least three reasons. First, not all states have the same RPS requirements. Second, even if they did have the same RPS requirements, the interconnection costs are likely to differ as a result of physical differences in transmission infrastructure. And, third, renewable generation projects are often built to serve customers located in different utility service territories and even in different states. This multistate issue has become highly contentious, as evidenced by a FERC docket involving the Midwest Independent Transmission System Operator's (MISO) proposed approach to allocating interconnection costs. In July 2009, MISO, in response to proposed actions by two MISO member utilities—Otter Tail Power and Northern States Power—filed revisions to its generation interconnection agreements. Those utilities threatened to withdraw from MISO if MISO's proposed cost allocation rules for transmission upgrades needed for renewable generation were continued.[31]

[31] *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER09-1431, July 9, 2009, Transmittal Letter, 5.

Under MISO's old tariff, new generators committed by contracts to supply capacity or energy to network customers for at least one year or more were entitled to be repaid 50% of the transmission upgrade costs necessary to interconnect their projects. For facilities rated 345 kV or above, 20% of the repayments were allocated to MISO on a system-wide basis and 80% were allocated among utilities based on Line Outage Distribution Factors. For facilities rated less than 345 kV, the repayments were entirely allocated to the utilities where those renewable generators are first interconnected.

Because a large percentage of MISO wind resources are located in the Otter Tail and Northern States service territories, these companies would be required to pass along costs that would result in significant rate increases under the proposed allocation rules. Instead, the two utilities want renewables developers rather than utility ratepayers to shoulder all of the interconnection costs.

In an October 23, 2009 order, FERC accepted MISO's two-phase proposal with an interim cost allocation methodology taking into effect immediately, whereby interconnecting customers who create the need for network upgrades bear 100% of the costs for upgrades rated below 345 kV and 90% for those rated 345 kV or higher. FERC also ordered MISO's stakeholders to engage in a process to determine a long-term methodology to be filed by July 15, 2010.[32] For the time being, renewable generation developers in the Midwest may find it more difficult to obtain financing for their projects.

This dispute clearly illustrates the inherent conflicts between policies that mandate new renewable resources and existing methods for allocating the costs of additional transmission infrastructure. However, the example also highlights additional problems faced in a multistate RTO setting. The RTO itself is designed to provide members cost savings that are a result of the benefits of increased coordination among members. If, as a result of cost allocation disputes, RTOs break up into smaller "sub-RTOs," those benefits will decrease.

More broadly, the MISO dispute clarifies the problem of "free riders." Specifically, depending on transmission cost allocation procedures, it is possible for states to impose

[32] *Midwest Independent Transmission System Operator, Inc.*, 129 FERC ¶ 61,060 (2009).

stringent RPS requirements and force other states to pay a portion of the resulting costs. That is clearly inequitable.

The Need for Broader Cost-Effectiveness Analysis

The transmission cost allocation issues that are arising because of RPS mandates raise a broader issue: how to meet specific public policy goals (e.g., reduced greenhouse gas emissions, reduced exposure to fossil fuel volatility, etc.) at the lowest possible cost. This is not the same as asking whether the benefits of the various states' RPS mandates are equal to or greater than their costs, although ideally such exercises would take place. Rather, it means identifying the specific goals that policymakers wish to achieve and then determining the lowest cost way of achieving them, regardless of the benefits. Even this less stringent analysis does not appear to have been considered in the context of most RPS mandates.

In determining the most cost-effective approach, all of the related costs—generation and transmission upgrades—must be included. We believe that, in the case of RPS requirements, transmission interconnection costs were an afterthought. If an RPS is determined to be the least-cost policy approach to achieving these goals, then the costs should be allocated broadly, as they are with many public goods.

The current situation, where states mandate the development of renewable generating resources and, at the same time, impose transmission cost allocation policies that make such development financially infeasible, is clearly unworkable.

The same is true of multistate RTO efforts to allocate transmission interconnection and network upgrade costs. Allocating transmission interconnection and upgrade costs to renewable generation developers may serve to preclude that same mandated development. Yet, allocating costs to utilities whose service territories happen to be in the areas where renewable resources are abundant, but designed to meet the requirements imposed by other states, is inequitable.

Ultimately, because cost allocation is a zero-sum game, if we identify the lowest costs needed to meet policy goals we can at least reduce the costs to be allocated. Doing so may reveal that RPS requirements, at the ever-higher levels being proposed, may not the best solution.

3. Policy Recommendations

It has been almost ten years since FERC Order 2000 created RTOs and ISOs in order to establish competitive power markets and to stimulate the development of new transmission to enhance competition. Now, the dominant behavior of the incumbent transmission owners, expressed through their RTO and ISO transmission expansion planning processes, is at loggerheads, albeit unintentionally, with public policies aimed at developing renewable energy resources.

In meeting state-mandated portfolio standards, it will be essential to ensure the deliverability of renewable generation to load. RTOs' expansion planning processes must include a way to identify the necessary deliverability network upgrades to timely and reliably deliver sufficient renewable energy and coincident capacity to satisfy the applicable RPS. These projects, when approved, should be open to development by any party, independently of being current owners of transmission or not. Ultimately, if no one shows interest in developing the necessary deliverability network upgrades, the state may have to front the cost of building the upgrades and recover the investment through an existing or new transmission access charge.

The approval process for necessary deliverability network upgrade projects should be free of undue influence by any particular stakeholder group. Projects should be prioritized based on their ability to facilitate the timely achievement of RPS goals and prioritized on a least-cost basis.

To avoid overestimating the cost of upgrades, RTOs must devise mechanisms to assess the viability of renewable projects in the interconnection cluster under study. They must also plan alternative cost scenarios grouping applications with different levels of viability to help developers judge what the most likely cost of the deliverability upgrades will be. This may require FERC concurrence on the nondiscriminatory nature of the process. If an RTO or an ISO still operates a serial interconnection queue, it should modify its LGIP process to study clusters of geographically proximate interconnection applications.

All renewable projects should be required to have capacity deliverability based on statistical estimates of their capacity during system peak and during project peak generation conditions. This would ensure a fair distribution of the up-front funding responsibility for network upgrade costs. LSEs buying the output of the projects should be required to front the network deliverability upgrades in proportion to their share of each renewable generation project output at the time of the generator's largest impact on deliverability.

Most importantly, state legislatures must estimate and consider the cost of the transmission necessary to develop new renewable resource areas *prior* to increasing RPS goals. Statewide renewable transmission needs assessment efforts like RETI and Texas CREZ should become the norm not the exception in state RPS planning. An early assessment of the impact of the expected cost on retail rates should provide a good measure of how high to set state or federal RPS goals.

If mandatory state, and perhaps federal, RPS requirements are to exist, renewable generation should be treated like a public good. The load serving entities that need the renewable generation should finance the necessary interconnection costs. It makes no sense to mandate renewable generation but to continue transmission interconnection processes that make it impossible for such generation to finance interconnection costs. Too many RTOs continue to have interconnection requirements that are biased toward existing TOs (e.g., New York) or saddle renewable generators that happen to occupy certain spots in the queue with extraordinary upgrade costs.

Finally, policymakers need to rethink RPS requirements to make sure they are the most cost-effective means of achieving specific policy goals. In the case of RPS requirements, it seems that an urge to "do something" has, in some cases, overshadowed the complex but necessary task of considering existing transmission policies both in a broader context and in relation to new policies. The failure to do so has created inconsistencies that have significant economic and environmental implications. Sooner or later, we will have to address them.