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Current Conflicts in U.S. Electric Transmission Planning, Cost Allocation and Renewable Energy Policies: More Heat than Light?

To surmount obstacles to expanding and upgrading the nation's transmission system that are impeding development of the renewables sector, it is critical that these issues be resolved quickly and on a consistent rather than ad hoc basis.

David Bloom, J. Paul Forrester and Nadav Klugman

I. Introduction and Background

Energy policy is increasingly the subject of mainstream political discussion. Candidates, pundits, policymakers, and voters actively debate the relative economic, environmental, and geopolitical merits of the sources from which electricity is produced, the promise of ''clean energy'' jobs, and the risk of spiraling costs for ratepayers and taxpayers. A majority of states have mandated the expansion of renewable energy in particular – both in the aggregate and relative to the amount generated by fossil fuels. Even as the ''climate change'' debate seems to have lost steam at the federal level, renewable energy remains popular. And all parties concede that achieving even the less ambitious renewable energy mandates will require expanding and upgrading the nation's transmission system, among other reasons because renewable energy resources are often intermittent

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and far from high-demand areas. In any event, projects to improve the system's efficiency and reliability would be necessary even in the absence of such mandates. Various studies have pegged the costs of these upgrades in the tens of billions of dollars.

However, there is much less agreement on how these upgrades should be planned, who should have the right to construct them, and, finally and most importantly, who should pay for them. The future of renewable energy in the United States will depend heavily upon the resolution of these and related questions. This article will discuss three concerns in particular that have been raised as obstacles to expanding and upgrading the nation's transmission system. And it will conclude that (1) it is critical to the development of the renewable sector that these issues be resolved quickly, and (2) it is equally critical that these issues be resolved on a consistent basis, one that prevents the development of contradictory approaches, which in turn stymie the development of a *national* renewable sector.

First, and most important, there is no set of uniform rules for allocating the costs of transmission projects. Different approaches have been taken, including (1) allocating the costs to the renewable energy generation projects being built (and thus the most immediate ''cause'' of a given transmission project), (2) allocating the costs to all regions in which the new transmission facilities are located, including ''source,'' ''sink,'' and transit-only areas, and (3) allocating the costs to markets only. These approaches vary based upon a participant's view as to whether the promotion of renewable energy is a national priority, an opportunity for the generator, or a policy decision by markets.

Renewable energy developers generally favor broad cost allocation, arguing for an expansive concept of the benefits of new transmission construction and, consequently, of the ''beneficiaries'' who must also bear the costs. They argue that upgrades which are necessary to incorporate new renewable generation benefit the transmission system and consumers generally, and support national policies that provide benefits to all citizens. They therefore conclude that concentrating all cost responsibility on the applicable generator fails to recognize the wide distribution of these benefits and, by so doing, reduces the likelihood that a given project will be developed and that the projects which are developed will be as efficient as possible.

First, and most important, there is no set of uniform rules for allocating the costs of transmission projects.

In contrast, ratepayers in regions where transmission upgrades are necessary but where the renewable energy is not consumed want no part of the costs, rejecting the claims of carbon reduction and fuel-source diversity. This is particularly the case when ratepayers are located in a transit zone and, therefore, are benefitting directly neither from the generation facilities nor the generated power.

Many markets argue that the costs should be broadly socialized and certainly not limited to end-user markets. Again, their view is that renewable energy should be a national policy and that the burdens of implementing that policy should not fall solely on a restricted class of customers.

Even where there is a decision to, for example, allocate all costs to generators requesting service, there are arguments over the relative allocation amongst generators and how to avoid effectively granting subsidies from early developers to subsequent ones. For example, should the costs of transmission upgrades be considered and allocated on a first-come, first-served basis, or in baskets of similarly situated projects? The realities of this complex issue would become apparent when a generator suddenly faces significantly increased costs of interconnection because a higher-ranked generator has dropped out of the queue, with the result that system upgrades

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originally allocated to the higher-ranked generator become the responsibility of the lower-ranked generator.

As a result of these competing positions, regulators, the nine regional transmission organizations (RTOs), and independent system operators (ISOs) have struggled with these issues, taking differing approaches on cost allocation, particularly complicating the planning and implementation of multi-regional projects. But, of course, predictability of cost recovery is critical to facilitating investment. Many industry players and observers are concerned that these regional differences may lead to misallocation and regulatory arbitrage; they are concerned, too, that uncertainty about federal plans to address the variation is complicating the planning processes for generators and utility companies that operate in multiple regions and impeding, or at least delaying, necessary transmission development.

Second, some have identified deficiencies in transmission planning processes. Prior to the retail restructuring of the electric industry in many parts of the U.S., electricity generation and transmission were planned jointly to serve native load, which was directly responsible for all costs. The process is more complicated when de-regulated transmission must be planned to serve de-regulated generation and wholesale power markets. According to renewable energy advocates, the failure of transmission planning processes explicitly to address state and federal energy policy objectives will lead to a transmission system that is incapable of achieving them, threatening the viability of renewable energy mandates. The prime example of this failure is a cost allocation scheme that too narrowly defines the benefits of renewable energy generation – ignoring, in this view, environmental, geopolitical, and societal benefits which have been advocated and mandated by elected officials and yet are not achievable without transmission upgrade and expansion. Additionally, the absence of a national – or even a multi-regional – transmission planning process is thought especially to inhibit interregional and multi-regional projects that may address transmission needs most efficiently and may be necessary if a given state with an aggressive renewable mandate is located far from the most ideal renewable resources. There is a great risk that a transmission grid that is designed in increments, based on single or batched requests for service, will end up with a sub-optimal design and that costs will be misallocated, simply due to the placement of a project in a first-come, first-served queue. And the fact that transmission siting is almost exclusively approved at the local level means there is a very real risk that the development of an efficient national grid, connecting renewable resources with markets, will be impeded.

There is considerable disagreement about the appropriate scope of the rights and obligations of ''incumbent utilities'' to expand and upgrade transmission systems.

Finally, there is considerable disagreement about the appropriate scope of the rights and obligations of ''incumbent utilities'' to expand and upgrade transmission systems and the appropriate degree of participation by non-incumbents. Many parties are interested in developing new transmission projects, whether on a merchant basis or to connect their own generation facilities and to provide service to others. On the other hand, traditional utilities want the first option to construct new transmission lines and add to their rate bases and, of course, returns. As with cost allocation, states, RTOs, and ISOs treat incumbents differently. Generally, public utilities have obligations that often include responsibility for system reliability and the construction of new facilities or upgrades. Certain regions also grant incumbent utilities a right to build transmission facilities within their respective footprints even if a merchant developer has planned a similar project as part of a

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regional planning process – a so-called ''right-of-first-refusal.'' Renewable energy developers, among others, argue that rules which favor incumbents discourage competition, reducing the number and quality of proposed transmission projects, increasing costs to ratepayers and negatively impacting the efficiency of the grid. They are concerned that projects will not be planned and developed if an incumbent utility can effectively obtain the benefits after much of the hard work already has been done.

The situation is further complicated by the fact that the U.S. Federal Energy Regulatory Commission (FERC) sets rates and terms and conditions for almost all transmission in the lower 48 states, while the states are responsible, with limited exceptions, for the approval of the construction of new transmission lines. Therefore, the states would have effective means to respond to FERC decisions, particularly on cost allocation, that they oppose.

Each of these issues has been debated before Congress, state legislatures, and FERC and is the subject of a new set of proposed rules issued by FERC, as well as FERC action on specific proposals. Given the fact that the next Congress is unlikely to tackle comprehensive energy legislation, the bi-partisan FERC will likely be making decisions that shape U.S. energy policy for decades to come.

II. Discussion

In 2007, FERC issued Order 890,[1] which addressed the *pro forma* Open Access Transmission Tariff (OATT) process, requiring each public utility transmission provider to implement a transmission planning process that incorporated nine ''planning principles.'' Among the nine transmission planning principles set forth in Order No. 890, seven – coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies – are also the subject of FERC's new proposed rules. When an RTO or ISO seeks approval of its OATT, FERC will review Attachment K (Planning) thereto, and the RTO or ISO will seek to convince FERC that its planning process is consistent with or superior to the planning principles in Order 890. Although the principles are uniform, the implementation differs by region and it is this differing implementation that is causing concern; to illustrate regional differences, it is helpful to consider examples of recent proposals. These proposals illustrate the wide range of approaches that are being taken, and the different potential consequences for renewable generation.

There is concern that projects will not be planned and developed if an incumbent utility can effectively obtain the benefits after much of the hard work already has been done.

On June 17, 2010, FERC approved revisions to Attachment K of the OATT of Southwestern Power Pool, Inc. (SPP), a RTO whose region includes parts of nine states.[2] The FERC order allows SPP to adopt the so-called ''Highway/Byway Methodology'' for allocating the costs of transmission system upgrades and expansions. Under the SPP methodology, ''highways'' are high-voltage lines of 300 kV or higher; ''byways'' are lower-voltage projects that are thought to provide fewer region-wide benefits. Because the SPP believes that ''highways'' will generate the greatest benefits across the SPP region – decreasing congestion by redispatching larger amounts of energy, reducing cost by reducing line losses, and improving grid reliability by efficiently transporting energy over greater distances – their cost is allocated most broadly, to electric utilities across the region on a ''postage stamp'' basis, which is based on each entity's historical use. For facilities between 100 kV and 300 kV, which are thought to provide fewer regional benefits than ''highways,'' one-third of the cost is allocated in the same manner as the cost of ''highways,'' while the remainder is allocated to the utility in the zone in which the facilities are located. For facilities

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operating below 100 kV, all costs are allocated to the utility in the zone in which the facilities are located. Finally, the SPP tariff reserves special treatment for transmission costs associated with a wind resource that is not located in the transmission customer's delivery zone – it will allocate costs for these facilities operating at 300 kV or higher 100 percent on a regional postage stamp basis and, for facilities operating at less than 300 kV, 67 percent regionally, with the balance allocated to the transmission customer.

The SPP methodology clearly attempts to address the cost-allocation concerns of the renewable energy industry. By allocating costs to all users in the SPP region or in the affected zone (or to some combination of the two), the SPP OATT avoids making generators responsible for the full cost of the transmission system upgrades that their facilities require, reducing the costs to developers. The methodology also socializes costs across the SPP region, regardless of source or sink.

The SPP proposal that FERC approved also modifies incumbent rights of first refusal: incumbent transmission owners have rights of first refusal within their service territories but are also builders of last resort. If the SPP planning process identifies a transmission project to be built, the applicable transmission owner has the opportunity to build it but is also required to build it if no other entity can be found. This clearly is SPP's attempt to find compromise between the status quo, largely defended by incumbents, and the demands of renewable energy developers.

On July 15, 2010, FERC conditionally approved another revision to SPP's OATT – a modified transmission planning process (the Integrated Transmission Plan).[3] The Integrated Transmission Plan would replace the current planning process, which consists of a single, annual process, with three distinct planning sub-processes: a 20-year assessment, to occur triennially and focusing on ''highway'' projects; a 10-year assessment, also to occur triennially and focusing on 100–300 kV ''byways'' and other issues not resolved in the 20-year assessment; and a near-term assessment, to occur annually and focusing on reliability and compliance with requirements of the North American Electric Reliability Corporation. Projects approved through one of the Integrated Transmission Plan processes would be entitled to cost recovery under the Highway/Byway methodology.

The SPP methodology clearly attempts to address the cost allocation concerns of the renewable energy industry.

Also on July 15, 2010, the Midwest Independent Transmission System Operator, Inc. (MISO) submitted to FERC a proposal regarding allocation of costs of new transmission projects which differs considerably from the Highway/Byway structure.[4] Under MISO's proposal, the costs of new transmission projects designated as Multi-Value Projects (MVPs) – much like SPP's ''highways,'' these are projects which provide substantial reductions in regional congestion costs, reductions in transmission losses, or reductions in installed capacity requirements – would be allocated to all ratepayers within the MISO region, which includes 13 Midwestern states and one Canadian province, as well as to those to which energy is exported from the MISO region. For generation interconnection projects, costs would continue to be allocated to the developer whose project requires the interconnection upgrade, except that for projects of 345 kV and above, 10 percent of the costs would be allocated to the system generally. To avoid the concern that the first developer would be subsidizing interconnection projects from which subsequent developers would benefit, the proposal would require later generation projects to reimburse earlier generation projects for the cost of transmission system upgrades which the later generation projects use. Unlike SPP, the MISO proposal places

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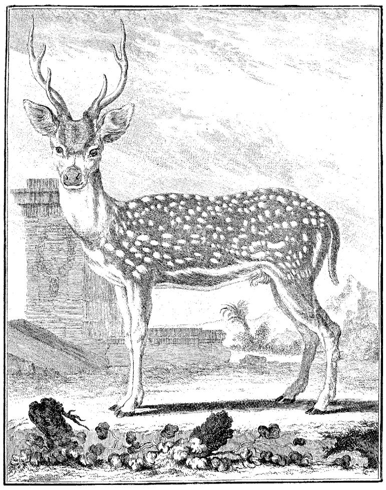
additional financial burdens on developers, particularly renewable energy developers, though the introduction of the special allocation for MVPs is a significant improvement for the renewable industry over an interim proposal, heavily criticized by the renewable industry, under which generators were responsible for nearly all costs.

The SPP and MISO proposals illustrate two of many divergent approaches to cost allocation. In addition to the variables highlighted in the SPP and MISO proposals (namely, location of generation and transmission voltage), cost allocation methodology may consider, among other variables, peak load, MW hours of consumption, impacts on power flow (i.e., reliability impacts) and purely monetary metrics (i.e., identifying the financial beneficiaries of a given project); each combination of variables provides different incentives to generators and consumers and poses a different administrative burden. In October 2009, during a series of regional conferences that FERC convened to monitor the implementation of Order 890, it confronted many other examples of divergence with respect to cost allocation and other issues. In proposing new rules on June 17, 2010, relating to cost allocation, incumbent building rights, and regional planning processes, FERC expressed concern, reflected in the SPP and MISO proposals and comments made in connection with the 2009 regional conferences that, absent reform on each of these issues, they would impede the development of necessary system upgrades and expansion.[5]

The proposed rules address cost allocation in detail. Transmission tariffs, which are subject to FERC approval, would be required to set forth the principles on which cost allocation will be determined for

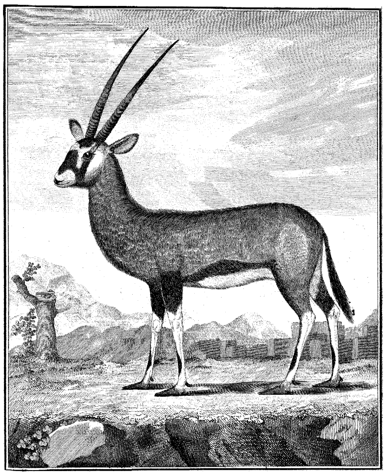


the particular region. The cost allocation methodology set forth in the tariffs would not need to be uniform for each project or type of project (it could differ, for example, for projects completed for reliability issues as opposed to public policy goals), but would be required to reflect ''cost causation,'' the principle that the parties that ''cause'' the cost to be incurred must be responsible for at least some portion of those costs and also to ensure that all beneficiaries of a project, not solely those that volunteer, contribute to cost recovery (i.e., to mitigate the ''free rider'' problem), notwithstanding the natural tension with the cost causation principle. Cost allocation methodology would also be required to assign costs among regions for interregional projects, though not for single-region projects.

More specifically, the cost allocation principles for a given region would be required to address six related criteria: (1) costs must be allocated to those that benefit from the facilities in a manner that is at least roughly commensurate with the benefits, which can include the benefits of achieving public policy requirements; (2) those that receive no benefits must not be involuntarily allocated costs; (3) the benefit-to-cost threshold used for planning must not be so high as to exclude projects with net benefits; (4) costs should not be allocated outside the affected region (or regions) without consent; (5) the cost allocation must be transparent; and (6) recognizing the complexity of the grid, different allocation methodologies may be used for different types of projects, such as projects for reliability, congestion relief, or public policy goals.

Finally with respect to cost allocation, recognizing that many projects affect more than one region and that the current planning processes do not adequately address interregional effects, the proposed rules would require neighboring transmission planning regions to develop a cost allocation method for transmission facilities located within both regions. Interregional plans would be required to address six related criteria essentially like those identified above, but interregional cost allocation plans would not be required to be identical to intraregional plans, nor would the neighboring regions be required to have identical plans. Thus, FERC does not even propose to fully resolve the issue of how major, multi-region projects will be proposed, planned and financed. And it does not address how diametrically opposed views will be accommodated. But, in many respects, this is the heart of the problem – ratepayers in Midwest wind-generating areas will not want to pay the costs of transmission installed so that East Coast utilities can meet renewables standards. And East Coast ratepayers will argue that wind power produces local benefits and that transmission cost allocation should support national energy policy objectives.

Although FERC Order 890 required regional coordination in transmission planning, it did not explicitly require the regional processes to develop regional transmission plans, an omission that FERC remedies in the proposed rules. FERC proposes to require regional plans because it believes, drawing on evidence of considerable intraregional differences in transmission costs and acknowledging that renewable resources are often located far from load, that the absence of such plans will lead to greater reliance on local, rather than regional, projects. The planning processes that would produce the regional plans would require participation by all transmission providers and would explicitly be required to address cost allocation and to consider how best to achieve ''public policy requirements'' in a cost-effective manner. While public policy is not limited to renewable portfolio standards and other renewable energy mandates–and responses to the proposed rules have



revealed the difficulties in defining the scope of public policy – the proposed rule is clearly intended to require transmission owners to address and thus help facilitate states' ambitious renewable targets. The plans would also be required to address seven of the planning principles enumerated in Order 890 and noted above.

Additionally, to help facilitate interregional planning, the proposed rules would require each public utility transmission provider, through its regional planning process, to enter into regional planning agreements with its counterparts in neighboring regions and to file these agreements with FERC. These interregional planning agreements would be required to contain a commitment to share information and a formal procedure for identifying and evaluating interregional projects.

As noted above, the proposed rules express a concern, previously the subject of debate before FERC,[6] that non-incumbent transmission developers are disadvantaged relative to incumbents, negatively impacting overall development. The proposed rules would address that concern by (1) eliminating any right-of-first-refusal that incumbent transmission providers currently enjoy to build projects in their respective service areas, and (2) requiring each public utility's transmission planning process to incorporate several protections for non-incumbents. Among the protections is something that looks very much like a right-of-first-refusal – sponsors that propose facilities which are selected through the planning process, whether initially or in a subsequent planning process within five years, would have a right to construct and own the facility, the so-called ''squatter's right'' for proposed projects – as well as a requirement to allow non-incumbents to recover costs of transmission projects in the same manner as incumbents. Additionally, each transmission plan would need to establish ''appropriate qualification criteria,'' including financial and technical competence, for determining whether an entity can propose a project during the planning process.

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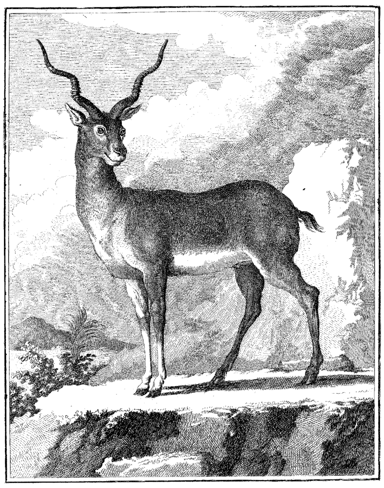
III. Issues Raised by Responses

As expected, the proposed rules were controversial, and the responses have raised several important issues.

A number of responses to the proposed rules highlight the fact that Order 890 was issued relatively recently, and that planning processes complying with Order 890 are just being implemented.[7] These processes have identified various projects that are just beginning construction and thus question the assertion that the existing rules are inadequate. From this vantage, not only should approved projects not be subject to new approval, the regional plans developed under Order 890 and approved by FERC – for example, the SPP's Highway/Byway structure[8] – should be given more time to be developed. While this response addresses the proposed cost allocation rules less directly, it certainly questions the need for revisions to regional planning processes. Public utilities, RTOs and ISOs have also sought to confirm the retention of local control over planning processes, asserting that even if agreed principles must be incorporated, entities with detailed knowledge of the region should retain discretion to implement the principles.[9] The renewable energy industry, in contrast, has expressed concern that the imposition of principles only, rather than uniform rules, would not dampen the potential for, or the impact of, differing rules in neighboring regions.[10]

The proposed elimination of rights of first refusal and the establishment of protections for non-incumbents – including the squatter's right for proposed projects – have generated the most disagreement, with some comments pointing out, as a threshold matter, that cost



allocation and interregional transmission planning are far more likely to impede transmission development than rights of first refusal, and urging FERC to focus on those more important issues.[11] Comments to the proposed rules have indicated that providing a squatter's right encourages the submission of many proposals rather than the most realistic, efficient projects, and may lead to the submission of proposals that are premature or insufficiently developed.[12] This could lead to duplication, additional administrative burden, and disputes regarding similarity. The squatter's right also fails to differentiate based on the competence and experience of the proposed sponsor, though the establishment of qualification criteria, as the proposed rules require, could be drafted in a manner that threatens the participation of non-incumbents. More fundamentally, there is concern that providing a squatter's right discourages collaboration of the sort that will be required amongst transmission providers to construct new projects most effectively.

In their comments, incumbents have stressed that differing treatment of non-incumbents is well-grounded. They argue, for example, that incumbents have greater knowledge of customer needs and local landowners, and thus are more likely to propose projects that are realistic and responsive to local needs. They contend that many non-incumbents will have little or no operating experience, a critical factor given the lifespan of transmission facilities; not surprisingly, non-incumbents object to the assertion that they lack the operating capacity to build needed upgrades and expansions.[13] There is also concern that Balkanization of the grid will increase the complexity and cost of grid coordination and management and reduce competition and efficiency, both of transmission and generation.

Finally, numerous comments have pointed out that non-incumbents which are not public utilities are not subject to same legal obligations under state law; for example, to maintain system reliability, to provide service at

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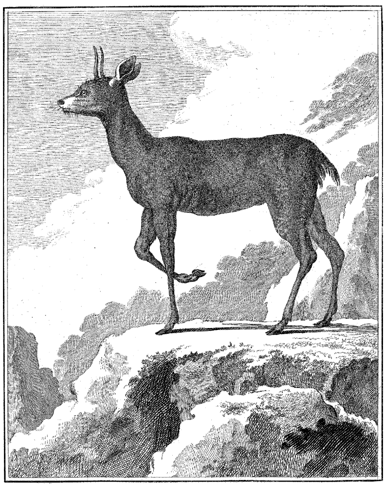
the lowest reasonable cost, and correspondingly, the obligation to build new transmission projects. Having these obligations without a corresponding right of first refusal would, according to the utilities' line of reasoning, pose an unjust financial burden.[14] Merchant developers would be in a position to propose only the most profitable projects, while incumbent utilities would be obligated under state law to build less profitable ones. FERC anticipated this argument and noted that non-incumbents have offered to assume the same obligations as apply to incumbents in exchange for the right to build and recover costs.

Although not necessarily a substantive argument, some existing utilities have threatened to reconsider their voluntary participation in RTOs and ISOs if rights of first refusal are eliminated, even though in the proposed rule FERC rejects the argument that providing rights of first refusal was a quid pro quo for convincing utilities to join RTOs and ISOs. Others have taken a less aggressive approach but have still insisted that they retain the right to build upgrades to their existing facilities. Finally, several responses to the proposed rules have questioned FERC's authority to require elimination of rights of first refusal.[15] They posit, among other arguments, that the choice of who builds a project is one of state law and one which Congress did not want FERC to supersede and that in order to justify its proposed rules, FERC would need to provide evidence of undue discrimination or pervasive unjust and unreasonable transmission rates; further, they argue, FERC it has not done so and, in any event, the proposed rules exceed by any rational measure the efforts that would be required to encourage development by non-incumbents.



The responses with respect to the cost allocation proposals have been generally less contentious. Some have noted that while the proposed rules require costs to be allocated based on the receipt of ''benefits,'' they do not sufficiently define the scope of such ''benefits.''[16] Other responses have indicated that while the proposed rules would require the development of cost allocation rules incorporating certain principles, FERC has not as yet proposed a deadline for proposing and implementing such rules; these comments suggest that FERC impose a default set of rules in the event that a region fails to adopt rules by a set deadline.[17]

IV. Conclusions

These are clearly very complicated issues, and the solutions will depend upon how the importance of renewable energy is ranked vis-à-vis other priorities, such as ''strict'' cost causation, lower rates, and similar factors. However, if the U.S. really intends to pursue renewable energy and if FERC becomes the focus for this development due to Congressional gridlock, then we believe that several conclusions follow.

First, cost responsibility for system upgrades should be broadly based, reflecting the benefits that renewable energy projects provide to all citizens. The burdens of renewable energy should not be restricted to a few, as the benefits serve all. This suggests that, at the very least, there should be broad allocation of the costs of high-voltage transmission to move renewable generation to load.

Second, there should be consistency in the process. It makes little sense for a generator and a market to deal with multiple transmission systems, each of which takes a different approach. That effectively results in no policy at all.

Third, and driven by the first two, cost responsibility should be considered on the basis of broad groupings of projects, even if broad cost allocation is rejected. It does not produce efficient results if the first-in-line of a series of renewable projects is saddled with massive costs, while subsequent generators in the

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same area receive the benefits of inexpensive system expansions.

Fourth, the sector requires some certainty. Against this must be balanced the need for regulators and policy to respond to changed circumstances. An appropriate balance must be struck, and we believe that regulators should establish a ''window,'' during which policies would not change with respect to all generators who reach defined benchmarks.

Fifth, the question of the rights of incumbent utilities to build system expansions and upgrades is complicated. On the one hand, it is inefficient to encourage non-traditional transmission companies to develop projects, only to see them usurped by incumbent utilities. On the other hand, incumbent utilities will suffer if they are forced to construct only those projects that new players find to be unattractive. We believe that a potential compromise would allow incumbent utilities to participate in new projects as minority co-venturers, based upon a reasonable reimbursement of costs, while maintaining control in the original project sponsor.

At the end of the day, however, what the country needs are consistent, predictable rules and, more fundamentally, a policy decision on whether renewable energy projects are a national priority or merely a local preference. Only once that policy is made will the answers to these complicated transmission policy questions become clearer.■

Endnotes:

1. *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 2006–2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,241, *order on reh'g*, Order No. 890-A, 2006–2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

2. *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010).

3. *Southwest Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010).

4. See Docket No. ER10-1791 – Midwest Independent Transmission System Operator, Inc. *et al*. submits the proposed revisions to their ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

5. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Notice of Proposed Rulemaking, IV FERC Stats. & Regs., Proposed Regs. ¶ 32,660 (2010) ("Transmission NOPR").

6. *Primary Power, LLC*, 131 FERC ¶ 61,015 (2010) (reh'g pending) and *Cent. Transmission, LLC v. PJM Interconnection L.L.C.*, 131 FERC ¶ 61,243 (2010).

7. See, *inter alia*, Comments of Northern Tier Transmission Group submitted by Desert Generation & Transmission Co-operative, Inc., Idaho Public Utilities Commission, Montana Public Service Commission, PacifiCorp, Public Utilities Commission of Oregon, Utah Public Service Commission, Idaho Power Company, Montana Consumer Counsel, Northwestern Energy, Portland General Electric Company, Utah Associated Municipal Power Systems and Wyoming Public Service Commission, in response to the NOPR on Sept. 29, 2010 (hereinafter, ''Northern Tier Comments'').

8. Members of the SPP requested that FERC not disrupt the development of SPP's approved structure. See, *inter alia*, Comments of Westar Energy, Inc. and Kansas Gas and Electric Company, submitted in response to the NOPR on Sept. 29, 2010.

9. See, *inter alia*, Comments of ISO/RTO Council submitted in response to the NOPR on Sept. 29, 2010 (hereinafter, ''ISO/RTO Comments''). The ISO/RTO Council is comprised of the Alberta Electric System Operator (''AESO''), the California Independent System Operator, Electric Reliability Council of Texas (ERCOT), the Independent Electricity System Operator of Ontario, Inc. (IESO), ISO New England, Inc., Midwest Independent Transmission System Operator, Inc., New York Independent System Operator, Inc., PJM Interconnection, LLC, Southwest Power Pool, Inc., and New Brunswick System Operator (NBSO). The IESO, AESO, NBSO and, in respect of the issues presented in the NOPR, ERCOT, are not subject to the Commission's jurisdiction and did not join in these comments.

10. See, *inter alia*, Comments of the American Wind Energy Association, Wind on the Wires, Renewable Northwest Project, Center for Energy Efficiency and Renewable Technologies, Mid-Atlantic Renewable Energy Coalition, Alliance for Clean Energy, Inc., Interwest Energy Alliance, RENEW, and The Wind Coalition, submitted in response to NOPR on Sept. 29, 2010 (hereinafter, ''AWEA Comments'').

11. See, *inter alia*, comments of Southwest Power Pool, Inc., submitted in response to NOPR on Sept. 29, 2010.

12. See, *inter alia*, Comments of Edison Electric Institute, submitted in response to NOPR on Sept. 29, 2010 (hereinafter, ''EEI Comments'').

13. See, *inter alia*, Comments of Western Independent Transmission Group, submitted in response to NOPR on Sept. 29, 2010 (hereinafter, ''WITG Comments'').

14. See, *inter alia*, EEI Comments.

15. *Id*.

16. See, *inter alia*, Northern Tier Comments.

17. See, *inter alia*, AWEA Comments.