UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Processes Under Order No. 890	Docket No. AD09-8-000

COMMENTS OF THE TRANSMISSION ACCESS POLICY STUDY GROUP

Pursuant to the Commission's October 8, 2009 Notice of Request for Comments ("Notice"),[1] the Transmission Access Policy Study Group ("TAPS") comments on the very important issues of transmission planning and cost allocation.

I. EXECUTIVE SUMMARY

TAPS agrees that transmission planning and cost allocation are crucial issues that must be addressed in order to get the transmission infrastructure built that we need to reliably deliver existing and new resources, including renewable and low-carbon resources, to electricity consumers. We applaud the Commission's willingness to acknowledge existing problems and its decision to re-visit these often-thorny issues through this Request for Comment.

Recent experience has demonstrated that there are substantial opportunities to expand and strengthen transmission planning, especially at seams, and that properly designed joint planning processes can make significant progress toward a robust grid supported by broad consensus. Joint planning processes like CapX2020 ("CapX"), which focused on building the common infrastructure needed to deliver new resources to load in a variety of different generation scenarios, can produce major facility upgrades while

[1] *Available at* eLibrary Accession No. 20091008-3022.

being far less divisive and avoiding the controversy that has plagued efforts to promote a new 765 kV overlay. And because they are based on constructing transmission facilities that are useful in many different possible resource futures, joint plans like those produced by CapX will have lasting value and are better able to accommodate the wide range of emerging energy technologies. The Commission should adopt policies that support and build on these significant successes and can get much-needed transmission built promptly.

In considering new transmission planning requirements, the Commission should not prejudge the type of transmission facilities that are needed. TAPS has long argued for a stronger grid, but there is still significant uncertainty regarding evolving state and federal renewable energy policies (including, for example, the desire of many states and regions to develop and increase reliance on local renewable resources), as well as the effects of implementing new technologies. The assumption that we need 765 kV overlay lines to deliver wind from the Midwest to the East Coast may be incorrect. The Commission's goal should be an economical, integrated electric system, built and maintained for the benefit of consumers, that allows load-serving entities ("LSEs") to minimize total delivered electricity costs, including energy, transmission, back-up, and ancillary services. Particularly because a 765 kV overlay probably will not solve the local and intra-regional transmission constraints that currently prevent LSEs from reaching "nearby" alternative resources, any properly-designed transmission planning process must carefully weigh the value of such lines and compare it to the range of feasible alternatives before major new investment is undertaken.

The 765 kV vision, with its associated hefty price tag, is also impeding the ability to reach consensus solutions on cost allocation. The high stakes and questionable benefits for some regions have ramped up the controversy surrounding cost allocation and have made it much more difficult to reach broad agreement on how the costs of *any* transmission facilities will be shared. While TAPS has supported regional cost allocation of major backbone facilities to spread the cost burden and match cost responsibility to the regional benefits that will be realized, we strongly believe that interconnection-wide cost allocation is unjust and unreasonable and is *not* the answer. Nor is the answer participant funding, which forces one or more market participants to bear the cost of network upgrades that provide broad benefits that change over time in a dynamic AC grid, creating enormous free-rider effects.

To break through the current stalemate and avoid the pitfalls of these two extremes, TAPS urges the Commission to take a more active role than it has to date in guiding cost allocation policy, especially for transmission facilities that extend beyond a single transmission provider. The Commission, through rulemaking, should establish clear cost allocation principles for new transmission in approved regional and inter-regional plans, and should directly address and provide for rates that cross transmission provider boundaries. In that rulemaking, the Commission should remove impediments to the construction of needed new generation and give appropriate recognition to the multiple and changing benefits that will be provided over the life of major new transmission lines, but it must also ensure that a region, or sub-region, will not be assigned costs that are substantially disproportionate to reasonably anticipated benefits.

II. INTEREST OF TAPS

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.[2] As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members recognize the importance of a robust transmission grid, and have long been outspoken on the need for improved transmission and the ways to get needed transmission built. *See* TAPS, Effective Solutions for Getting Needed Transmission Built at Reasonable Cost (June 2004) ("TAPS White Paper").[3] Among other things, TAPS recognizes the critical roles played by an open, inclusive and transparent planning process, and fair cost allocation methodologies in achieving needed transmission expansion.

Communications regarding these proceedings should be directed to:

Roy Thilly, CEO
WPPI ENERGY
1425 Corporate Center Dr.
Sun Prairie, WI 53590
Tel: (608) 837-2653
Fax: (608) 837-0274
E-mail: rthilly@wppienergy.org

Robert C. McDiarmid
Cynthia S. Bogorad
William S. Huang
J.S. Gebhart
SPIEGEL & MCDIARMID LLP
1333 New Hampshire Ave., NW
Washington, DC 20036
Tel: (202) 879-4000
Fax: (202) 393-2866
E-mail: robert.mcdiarmid@spiegelmcd.com
cynthia.bogorad@spiegelmcd.com
william.huang@ spiegelmcd.com
jess.gebhart@spiegelmcd.com

---

[2] TAPS is chaired by Roy Thilly, CEO of WPPI Energy ("WPPI"). Current members of the TAPS Executive Committee include, in addition to WPPI, representatives of: American Municipal Power, Inc.; Blue Ridge Power Agency; Clarksdale Public Utilities; Connecticut Municipal Electric Energy Cooperative; ElectriCities of North Carolina, Inc.; Florida Municipal Power Agency; Illinois Municipal Electric Agency; Indiana Municipal Power Agency; Madison Gas & Electric; Missouri Public Utility Alliance; Missouri River Energy Services; NMPP Energy; Northern California Power Agency; Oklahoma Municipal Power Authority; and Southern Minnesota Municipal Power Agency.

[3] *Available at* http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/effectivesolutions.pdf.

III. PLANNING COMMENTS

A. Overview as to Planning

The Notice (at pages 2-3) summarizes concerns about the current planning process, especially with regard to inter-regional and inter-transmission provider ("TP") planning, and asks for comments on these concerns.

TAPS agrees that the current planning process is not creating a sufficiently robust grid. Order 890[4] made a good start toward providing the needed timely, inclusive and transparent regional transmission planning process, but it should be supplemented by an enhanced multi-TP and inter-regional planning process for multi-TP and multi-regional transmission projects. The objective should be to determine what new transmission facilities are required to meet the long-term needs of the nation's electric consumers on a cost-effective, highly-reliable and environmentally-responsible basis, taking account of alternative generation development scenarios, aggressive energy conservation and efficiency programs and distributed generation potential. The criteria for adequacy should include transmission facilities needed to

- develop new resources, including renewable and other low-carbon resources;
- deliver new and existing generation to meet regional reserve requirements;
- grant new long-term transmission rights to LSEs for their new long-term resources, as required by Section 217(b)(4) of the

[4] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,241 ("Order 890"), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,261 ("Order 890-A"), *order on reh'g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 F.E.R.C. ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 74 Fed. Reg. 12,540 (Mar. 25, 2009), 126 F.E.R.C. ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 F.E.R.C. ¶ 61,126 (2009), *review docketed*, No. 08-1278 (D.C. Cir. filed Aug. 22, 2008).

Federal Power Act ("FPA"), 16 U.S.C. § 824q(b)(4), and prevent the diminishment over time of existing long-term transmission rights;

- relieve congestion, minimize seams issues and ensure that trapped generation pockets do not exist; and
- provide LSEs with optionality to meet their service obligations economically through access to diverse resources.

In recognizing that we need a robust, adequate, reliable transmission system, TAPS emphasizes the need to plan for a "right-sized" grid—not under- or over-built. "Right-sized" means a reliable system that has minimal congestion for the delivery of generation (both existing and new resources, including but not limited to renewable and low carbon resources) to load. There needs to be a planning process in which generation and transmission are considered together, in order to ensure that an economical, integrated electric system is built and maintained for the benefit of consumers. While such processes are underway in some regions or subregions (*e.g.*, the Upper Midwest Transmission Development Initiative[5] and the studies undertaken by the ISO-New England at the request of the New England governors[6]), such a process is not in place in all regions.

We caution the Commission not to start with the assumption that the nation needs 765 kV overlay lines to deliver renewable resources to load. The 765 kV vision, with its associated hefty price tag (which will be further inflated by the incentive return on equity

---

[5] The Upper Midwest Transmission Development Initiative was launched in 2008 by Minnesota, Iowa, Wisconsin, North Dakota and South Dakota to promote regional electric transmission investment and cost sharing among the states. The initiative coordinates efforts among entities involved in transmission matters, including state regulatory agencies, transmission companies, utilities, independent generation owners and other key stakeholders. For more information, *see* http://www.misostates.org/UMTDIList.htm.

[6] *See* New England Governors' Conference, Inc., New England Governors' Renewable Energy Blueprint (2009), http://www.negc.org/documents/2009/Renewable_Energy.pdf.

the Commission has already awarded to lines that have been announced in advance of their inclusion in a regional planning process[7]), is not only impeding the ability to reach consensus solutions on cost allocation, but may be misguided. The assumption that we need 765 kV lines to deliver wind from the Midwest to the East Coast may be wrong for any number of reasons—including the desire of states and regions to develop their own renewable resources;[8] the astronomical all-in costs of wind power transported over long distances (inclusive of transmission, energy, marginal losses and back-up capacity); development of wind resources offshore of the East Coast; increased installation of distributed generation, including solar; and growing reliance on demand response.

Thus, we suggest that regional and inter-regional processes focus initially on immediate steps that can be taken to significantly reinforce the grid to meet consumers' needs, while providing flexibility for the future. Wise investment of transmission dollars would first concentrate on the major grid reinforcements that will be needed under a range of different scenarios, while building in optionality for future development. For example, planners could initially consider the significant upgrades required to deliver Midwest wind to Midwest load centers and rely on displacement to reach further eastward. To achieve this end, 345 kV lines to Midwest load centers can be reinforced using oversize towers and rights-of-way that will permit the cost-effective addition of a second circuit if needed at a later date. Similarly, DC collector points could be included

---

[7] *See, e.g., Green Power Express LP*, 127 F.E.R.C. ¶ 61,031, P 80 (2009); *Pioneer Transmission, LLC*, 126 F.E.R.C. ¶ 61,281, P 56 (2009); *Tallgrass Transmission, LLC*, 125 F.E.R.C. ¶ 61,248, P 58 (2008).

[8] Some state renewable portfolio standard ("RPS") statutes even include local generation and/or deliverability requirements. For example, the Ohio utilities subject to that state's RPS must meet half of their renewable generation obligation with power generated from renewable generating facilities within the state. The other 50% must be met with power that is deliverable into the state. *See* Ohio Rev. Code § 4928.64(B)(3).

in the design to facilitate implementation of DC options if that proves to be needed given the expected distribution of new resources, including renewables. By moving quickly to implement incremental, but substantial, "no regrets" steps, recognizing where we want to get to, we can achieve a robust, "right-sized" grid at a much lower cost, thereby largely avoiding difficult cost allocation issues. Although the option of building 765 kV "overlay" lines should not be ruled in or ruled out at this time, development of such facilities requires careful, disciplined study.

The approach TAPS is suggesting is consistent with the approach successfully undertaken by CapX, a joint transmission-planning process in the northern Midwest. CapX consists of eleven investor-owned, municipal and rural cooperative utilities in Minnesota, North and South Dakota and Wisconsin that have jointly planned, and have opportunities to share in the ownership of, needed transmission upgrades.[9] CapX planners evaluated various generation scenarios, and started by identifying and focusing on the substantial transmission facilities that were always required, regardless of the specific generation scenario studied. In its first phase, CapX is seeking to build backbone transmission lines—three 345 kV lines and one 230 kV line—to significantly strengthen the Minnesota transmission system.[10] These facilities are designed to meet the load-serving and reliability needs of all 11 participating utilities, and provide the common infrastructure to reach new sources of supply. The first phase is estimated to cost about $2 billion, [11] and there is an additional $1 billion of "partner" projects, which are related

---

[9] *See* CapX2020 frequently asked questions, http://www.capx2020.com/faq.html (last visited Nov. 19, 2009).

[10] *Id*.

[11] *Id*. CapX is beginning to plan its later phase projects. They will be focused primarily at enabling area

upgrades on individual systems. All four projects have received a Minnesota Certificate of Need,[12] and are at various stages of the process for obtaining a Minnesota Route Permit.[13] For one of the projects, the 230 kV line, no interventions have been filed in the Minnesota Certification of Need proceeding.[14] For the others, the primary issues that have been raised are that use of the lines should be restricted to transmission of renewable energy (which represents an engineering impossibility) and that the proposed 345 kV lines should be double circuited or possibly upsized to 500 kV.[15] This experience is certainly very different from the usual.

TAPS also stresses the need for the Commission to fulfill its mandate to facilitate planning for the reasonable needs of load-serving entities and for long-term rights, particularly for new resources, as Congress expressly directed in enacting FPA Section 217(b)(4) as part of the Energy Policy Act of 2005 ("EPAct 2005").[16] Section 217(b)(4) provides:

> The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to

---

utilities to meet their renewable energy needs under state law. The cost estimates range between $4 and $7 billion.

[12] *In re Great River Energy*, No. CN-06-1115, 2009 Minn. PUC LEXIS 1 (Minn. Pub. Utils. Comm'n May 22, 2009), *modified*, No. CN-06-1115 (Minn. Pub. Utils. Comm'n Aug. 10, 2009), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={BE377BE8-DEF9-4763-910A-70523BD56C8F}&documentTitle=20098-40627-01; *In re Otter Tail Power Co.*, No. CN-07-1222 (Minn. Pub. Utils. Comm'n July 14, 2009), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={EA1BC6A6-C854-48F1-9CEB-51568E6A6178}&documentTitle=20097-39617-01.

[13] *See Otter Tail Power Co.*, No. TL-07-1327 (Minn. Pub. Utils Comm'n); *Great River Energy*, No. TL-08-1474 (Minn. Pub. Utils. Comm'n); *N. States Power Co*., No. TL-09-246 (Minn. Pub. Utils. Comm'n); *N. States Power Co.*, No. TL-09-1056 (Minn. Pub. Utils. Comm'n).

[14] *See In re Otter Tail Power Co.*, No. CN-07-1222 (Minn. Pub. Utils. Comm'n).

[15] *In re Great River Energy*, *supra*, at 43.

[16] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

> meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

16 U.S.C. § 824q(b)(4).

Although the Commission has by rule implemented Section 217(b)(4) in Regional Transmission Organization ("RTO") areas as required by EPAct 2005 (through Order 681[17]), the adequacy of the grid to support the needs of LSEs remains a significant problem, especially when it comes to supporting long-term transmission rights for new generation resources. Despite the clear language of Section 217 and the passage of several years from the initial implementation of this provision, LSEs in various RTOs are increasingly concerned about their inability to secure long-term transmission rights for new resources. Although Order 681 recognized that planning for long-term rights was an important part of the Section 217(b)(4) directive[18] and, in approving RTO implementation of Order 681, the Commission expressly required planning for long-term rights to be integrated into the RTO planning process,[19] the problems that Congress sought to address through Section 217 have nevertheless continued. For example, we do

---

[17] Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, 71 Fed. Reg. 43,564 (Aug. 1, 2006), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,226, *corrected*, 71 Fed. Reg. 46,078 (Aug. 11, 2006), *clarified*, Order No. 681-A, 71 Fed. Reg. 68,440 (Nov. 27, 2006), 117 F.E.R.C. ¶ 61,201 (2006), *clarified*, Order No. 681-B, 74 Fed. Reg. 13,103 (Mar. 26, 2009), 126 F.E.R.C. ¶ 61,254 (2009).

[18] *See, e.g.*, Order 681 P 453 ("FPA section 217(b)(4) requires the Commission to exercise its authority under the FPA in a manner that facilitates the planning and expansion of transmission facilities, and to enable load serving entities to obtain long-term firm transmission rights. To implement that section in a transmission organization with an organized electricity market, as required by section 1233(b) of EPAct 2005, we believe that the transmission organization must plan its system to ensure that allocated or awarded long-term firm transmission rights are feasible.").

[19] *Midwest Indep. Transmission Sys. Operator, Inc.*, 121 F.E.R.C. ¶ 61,062, P 48 (2007), *order on reh'g*, 123 F.E.R.C. ¶ 61,178 (2008).

not believe that *any* LSE has been successful in obtaining long-term transmission rights for new generating resources in the Midwest ISO ("MISO"). Given the often-remote location of new generation resources, the unavailability of long-term transmission rights required to assure delivery at reasonable, predictable cost is a serious issue for LSEs that must commit to new long-term generation resources to serve their customers, including new renewable resources (assuming they otherwise meet the RTO's qualifications for long-term rights).

B. Responses to Commission Planning Questions

- *Are existing transmission planning processes adequate to identify and evaluate potential solutions to needs affecting the systems of multiple transmission providers? Should prospective transmission developers coordinate their projects in the interest of "right-sizing" facilities to make the best possible use of available corridors and minimize environmental impacts? If so, what process should govern the identification and selection of projects that affect multiple systems?*

- *Are there adequate opportunities for stakeholders to participate in planning activities that span different regions, including for example those undertaken pursuant to bilateral agreements?*

- *Is there adequate coordination among planning entities to provide consistency in the data, assumptions and models being used in planning activities?*

- *Will the interconnection-wide processes adopted pursuant to funding opportunities under the American Recovery and Reinvestment Act of 2009 result in an ongoing process for jointly identifying and evaluating alternatives to solutions identified in transmission plans developed through existing sub-regional and regional planning processes? Will the scope and function of these interconnection-wide planning activities be sufficient to help address the concerns identified above? How will planning activities conducted on an interconnection-wide basis be integrated into the development of sub-regional and regional transmission plans and vice versa?*

TAPS sees a need for enhanced planning, beyond the individual TP/RTO processes required by Order 890. We see real value in providing a vehicle for sharing the results of TP and RTO planning, to ensure that we're building the right projects and making the best possible use of our scarce resources—whether they be transmission dollars or available corridors—while minimizing environmental impacts. To that end, the Eastern Interconnection Planning Collaborative ("EIPC")[20] appears to be a useful approach that builds on existing modeling and planning to address inter-regional issues, rather than creating a new interconnection-wide planning organization.

While TAPS supports the "bottom up" approach that EIPC seems to be following, we have some concerns about the potential role to be played by vertically-integrated transmission providers and the treatment to be accorded the plans produced by such TPs, which may reflect the economic interests of their generation functions.[21] Even within an RTO, Transmission Owners ("TOs") that have the ability to withdraw have a disproportionate voice in the RTO's independent planning and cost allocation processes.[22] That situation is even worse in a non-RTO setting, where the transmission planning process remains fully under the control of the non-independent, vertically-integrated TP. For example, although Order 890 expressly recognized (at P 524) that "it

---

[20] *See* Eastern Interconnection Planning Collaborative, http://www.eipconline.com/ (last visited Nov. 19, 2009).

[21] This concern about the role of vertically integrated TPs amplifies the importance of ensuring that any inter-TP or inter-regional process needs to be open, transparent and collaborative, in accordance with Order 890. TDUs must have the opportunity to be actively involved. TAPS notes that the Commission has accepted as Order 890-compliant inter-regional/inter-RTO transmission planning processes that allow for only limited stakeholder participation in such joint planning. *See, e.g.*, MISO ASM Tariff, Attachment FF at Original Sheet No. 3434Q (providing for stakeholder consultation on only the "scope and results" of the inter-RTO Coordinated Regional Transmission Planning Study.) TAPS also recognizes the importance of state involvement, particularly in any multi-state planning process. We note the pivotal role played by the Southwest Power Pool ("SPP") Regional State Committee in the progress SPP has achieved on planning and cost allocation. Such state involvement is essential to implementation of what is planned.

[22] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,060, P 10 (2009) (noting MISO's claims that revised generator interconnection cost allocation methods were necessary in order to preserve the footprint given threatened departure of several transmission owners absent a change in the current cost allocation methodology).

is not in the economic self-interest of transmission providers to expand the grid to permit access to competing sources of supply," Order 890 left "the ultimate responsibility for planning" with the TP (P 454).[23] TAPS is concerned that vertically integrated TPs' control over their own plans and their role in the EIPC will undermine the credibility of the result.[24]

Further, we understand that EIPC is likely to be very high level and unlikely to deal with cost allocation, which is the crucial issue to getting transmission built. For these and other reasons, EIPC is unlikely to be the solution to all seams issues. For example, EIPC might not tackle the often-thorny and important localized planning issues that traverse existing TP or RTO seams. The Order 890 process requires TPs to coordinate their transmission planning with the planning of interconnected systems. Order 890, P 523. However, as recent proceedings have highlighted, this directive does not solve the many seams-related planning issues associated with even relatively local deliveries that are claimed to have impacts or parallel flows beyond a TP seam.[25] There is no clear mechanism for resolving these localized seams issues, which can stymie the

---

[23] Order 890-A (at P 178) denied TAPS' request to strengthen the construction obligations of the *pro forma* OATT ("Our focus is … on the process leading to the transmission plan and not the construction of specific facilities"), and (at P 180) declined "to impose additional accountability mechanisms" suggested by TAPS.

[24] *See generally* Transcript of the Joint FERC and State Regulator Conference on the State of Transmission in the Entergy Region Before the Federal Energy Regulatory Commission, Arkansas Public Service Commission, Louisiana Public Service Commission, Mississippi Public Service Commission, Public Utility Commission of Texas and Council of the City of New Orleans, *Entergy Services, Inc.*, Docket Nos. ER05-1065, ER09-555 (June 24, 2009) ("Entergy Transcript"), *available at* eLibrary Accession No. 20090624-4012. As announced at that conference (Tr. 226), and confirmed by letters from Chairman Wellinghoff to the participating state commissioners, the Commission is funding a portion of a study as to the cost and benefits of RTO participation by Entergy. *See, e.g.*, Letter to Arkansas Public Service Commissioner Suskie, Docket Nos. ER05-1065, ER09-555 (July 31, 2009), *available at* eLibrary Accession No. 20090804-0122.

[25] *See, e.g.*, *Sw. Power Pool, Inc.*, 127 F.E.R.C. ¶ 61,076 (2009) (note that settlement documents were recently filed in that proceeding). *See also* Deficiency letter in *Xcel Energy Services Inc.*, Docket No. ER09-1428-000 (Sept. 3, 2009), *available at* eLibrary Accession No. 20090903-3016.

grant of needed transmission service and delay construction of necessary upgrades. Thus, in looking at inter-regional issues, the Commission should not lose sight of the vital need to more effectively address more localized planning and cost allocation issues that traverse an individual TP or RTO seam.

- *How are reliability impact studies aligned with economic-based evaluations of sub-regional or regional projects and assessments of projects needed to satisfy renewable energy standards? If not aligned, how can reliability assessments and economic evaluations be aligned in order to better identify options that meet regional needs?*

TAPS has long questioned the validity or usefulness of categorizing a particular upgrade as "economic" or "reliability," and having that classification drive the treatment of such upgrade for planning and cost allocation purposes. In general, today's economic project is tomorrow's reliability upgrade and vice versa—almost every reliability upgrade has economic consequences. As the Midwest ISO recognized in its August 29, 2008 Informational Compliance Filing:[26]

> Through both experience with RECB I implementation, potential RECB II projects, and preliminary discussions around high voltage overlay and cross-border projects, it is apparent that in most cases it is nearly impossible to describe a project as solely required for reliability purposes or solely required for economic purposes. In fact, many of today's proposed RBP [economic projects] are transmission projects that are sized larger than required by current or near term reliability needs to capture additional economic benefits. However, these projects may in fact also be required to support reliability at some point in the future.

Unfortunately, calling a project "economic" often is taken to mean that it is not needed and won't get built. Notwithstanding Order 890, economic studies are not

---

[26] Informational Compliance Filing of the Midwest Independent Transmission System Operator, Inc., Docket No. ER06-18 ("August 29 Informational Compliance Filing"), *available at* eLibrary Accession No. 20080903-0303.

occurring in some parts of the country. Even if economic planning studies were undertaken, in many areas there is no accepted trigger for when an economic project should move forward. In other places, the threshold is impossibly high. For example, the Midwest ISO's August 29 Informational Compliance Filing describes (at 5, 10-12) that none of the "economic" projects tested as of that date had met the thresholds for designation and allocation as "Regionally Beneficial Projects."[27]

As discussed in Part III.A above, to achieve the "right-sized" grid, transmission planning studies need to integrate consideration of generation and transmission, so that consumers end up with power at a delivered cost that is reasonable. In the Midwest ISO, planning does take economics and renewable generation resources into account by use of Security Constrained Economic Dispatch. This evaluation is also part of Southwest Power Pool's ("SPP's") new Synergistic Planning Project approach.[28]

TAPS recognizes the difficult "chicken and egg" issues raised by transmission planning—*i.e.*, do we wait for generation to be proposed to be sure the transmission is needed, or do we move ahead with the transmission to support anticipated but not-yet-committed generation? TAPS believes that the CapX framework described above provides a sensible, proactive way out of that quandary, while ensuring that consumers

---

[27] This result is not surprising given the concerns expressed by commenters and recognized in the Commission's order accepting the "RECB II" cost allocation. *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 F.E.R.C. ¶ 61,209, P 157 (2007) ("However, we agree with commenters that the proposed Benefits/Costs Ratio thresholds may have the unintended consequence of disproportionately excluding long-term projects from regional cost allocation. Accordingly, we will require the Midwest ISO to include an analysis of the effectiveness of the Benefits/Costs Ratio thresholds as part of its reporting requirement. We would expect that, as the Midwest ISO gains experience projecting costs and benefits for particular projects, the conservatism reflected in the RECB II Filing would be adjusted. We also reiterate, as indicated above, the Midwest ISO should consider the feasibility of calculating other potential benefits over time.").

[28] Southwest Power Pool, http://www.spp.org/publications/SPP_Implements_Project_to_Create_Holistic_Planning_Vision.pdf (last visited Nov. 19, 2009).

will get value for their transmission investment: CapX examined alternative generation scenarios, and has moved forward on the major upgrades that were needed regardless of the specific location of new generator interconnections.

But it's not one size fits all. The Commission should recognize that especially when it comes to assessing economic benefits, different approaches and solutions may be appropriate in different parts of the country. For example, in New England, generation is almost totally deregulated and separated from transmission, but through such processes as ISO-New England's recent studies undertaken at the request of the New England governors,[29] generation alternatives are brought into the analysis to assess cost effectiveness.

- *How should merchant and independent transmission projects be treated for purposes of regional transmission planning?*
    - *Should they be required to participate in the planning process and, if so, at what point must they engage in the planning process?*
    - *Do rights of first refusal for incumbent transmission owners unreasonably impede the development of merchant and independent transmission? If so, how can this impediment be addressed?*
    - *Are there other barriers to the development of merchant and independent transmission in the transmission planning process?*
    - *Should similar assumptions regarding resource availability be used for generation owned by the transmission owner and merchant or independent developers?*

---

[29] *See* New England Governors' Renewable Energy Blueprint, http://www.negc.org/documents/2009/Renewable_Energy.pdf

TAPS has long been skeptical about market-based solutions to transmission. Once sufficient new transmission is built to address congestion, the LMP-based economic justification for a merchant transmission line evaporates. Thus, we have long argued that transmission construction cannot be supported by participant funding in exchange for FTRs whose value will be destroyed by the planned upgrade.

The dynamic, integrated nature of the AC grid means that once a new line is connected, it becomes part of the network, affecting and being affected by everything else going on in the system and changes thereto. This characteristic creates not only the potential for "free riders,"[30] but also the need to assure that grid additions are in fact beneficial from a whole-grid perspective. A pure "market-based" approach to transmission will not ensure that each upgrade wisely uses available corridors, minimizes environmental impacts, efficiently expands capacity and effectively reduces congestion.

For these reasons, any merchant transmission should be considered as part of the planning process. Otherwise, our nation will be saddled with transmission that is inefficient, both in terms of the delivered price of electricity and in terms of utilization of scarce resources and political capital in the often difficult transmission siting process.

Efforts to site major transmission upgrades are also far more likely to be successful if they are broadly supported by LSEs in the region as needed for multiple purposes, rather than merely a "merchant project." CapX's relatively smooth Phase I permitting experience to date (discussed above) is a positive example of how broad agreement on needed upgrades, bolstered through opportunities for joint ownership by LSEs, can facilitate siting.

---

[30] *See, e.g.*, Order 890, P 561.

Merchant HVDC lines similarly must be subjected to the planning process. While the transmission capacity of an HVDC is much less susceptible to influence by the surrounding AC system, its terminals are the equivalent of interconnecting a large generator into the AC grid, which must be able to integrate the resulting output or inflow. In addition, to efficiently build needed infrastructure and get it sited, merchant HVDC lines must be considered as part of the planning process.

Thus, merchant or independent transmission projects should be required to participate in the planning process once they have identified a potential project, and to advise planners of any alternatives studied to reduce potential duplication of effort.

Notwithstanding the strong need to incorporate merchant transmission projects into transmission planning processes, a number of HVDC and other high voltage overlay lines have been proposed, and have even applied for and been granted incentive returns by the Commission, without inclusion in the planning process.[31] While the Commission has typically conditioned such incentives on approval by a regional planning process,[32] that planning process seems to be treated as an afterthought that will rubber-stamp what has been proposed outside of that process. Transmission planning needs to be the main event, in which a determination regarding which projects to pursue is made after analysis of alternatives as to what transmission additions best meet the region's needs—*e.g.*, whether a 765 kV overlay should be constructed at all, and if so, where. Cost also doesn't seem to factor into the calculus of those proposing 765 kV overlay lines—it

---

[31] *See* n.7, *infra* (citing *Green Power Express LP*, 127 F.E.R.C. ¶ 61,031; *Tallgrass Transmission, LLC*, 125 F.E.R.C. ¶ 61,248; *Pioneer Transmission, LLC*, 126 F.E.R.C. ¶ 61,281).

[32] *See, e.g. Green Power Express LP, supra*, 127 F.E.R.C. at P 80; *Pioneer Transmission LLC, supra*, 126 F.E.R.C. at P 56.

seems to be assumed that others will pay, regardless of how high the price. The current "planning by PowerPoint" raises serious concerns as to whether the facilities built will be "right-sized," as they need to be if we are to deal with climate change and other energy challenges without undue burden on our economic well-being.

While TAPS is skeptical of merchant transmission and believes such projects must be integrated into planning (for the reasons discussed above), we recognize that merchant transmission, particularly in the HVDC context, can be effective in some circumstances,[33] and even AC projects that function as radial generator leads to renewable generation may be susceptible to a merchant model.

In addition, TAPS has long supported bidding out transmission ownership to third parties where the relevant TO demands incentive rates of return. As noted above, in Order 890-A (at P 178), the Commission declined to expand the transmission provider's obligation to construct transmission, leaving it up to the transmission provider to determine whether to build the transmission facilities identified in its transmission expansion plan. Where a transmission owner declines to build facilities in an approved plan, ownership and construction of the facilities should be put out to bid to other entities to achieve the lowest reasonable cost for consumers.[34]

Similarly, there should be opportunities for joint ownership in projects that emerge from the planning process, particularly if a transmission-dependent utility ("TDU") will be required to bear the cost of the facility, for TDUs that are located in or provide service to customers in the state(s) where the project is or will be located, or a

---

[33] *See, e.g.*, *Ne. Utils. Serv. Co.*, 127 F.E.R.C. ¶ 61,179 (2009).

[34] Order 890 (at P 594) merely encouraged third parties development and ownership of a project in those circumstances.

broader region where an RTO or ISO so provides. At minimum, where joint ownership has not been offered to public power, cooperative and other smaller load-serving entities on a reasonable basis, no incentives should be granted.

As recently noted in approving the SPP TOs' right of first refusal, the Commission is concerned that a TO right of first refusal could discourage third-party transmission developers from proposing projects, and raise the potential for discrimination in terms of pursuit of projects that benefit the TO, while precluding construction of lower cost or superior upgrades.[35] TAPS shares the Commission's concern. The TO right of first refusal, particularly when coupled with a TO's ability to include upgrades in its transmission ratebase, gives incumbent TOs a big advantage, allows them to shape projects to meet their needs, and discourages third-party developers from proposing transmission that may be more cost-effective. In areas where the TO is not inclusively owned, the Commission should consider taking steps (beyond merely limiting the time in which a TO may exercise it right of first refusal) to make sure the transmission projects that are most efficient for consumers are constructed in the most cost-effective way.

As to the Commission's final question on assumptions used for resource availability,[36] TAPS fails to see the justification for using different assumptions regarding resource availability for generation owned by the TO versus merchant or independent developers.

---

[35] *Sw. Power Pool, Inc.*, 127 F.E.R.C. ¶ 61,171, P 43 & n.34 (2009).

[36] TAPS understands "resource availability" in the classic industry definition of the term, meaning the ability of a generator to produce energy, accounting for forced outages and generation facility maintenance.

- *Is the interconnection queue process hindering the ability to plan the transmission system to integrate new generation? Would any reforms to the Commission's interconnection procedures support efficient planning of the transmission system?*

TAPS agrees that the interconnection queue poses significant obstacles to getting new generation timely integrated into the grid. The Commission has specifically recognized this issue and required RTOs to take remedial steps to address it.[37] This effort has resulted in the institution of queue reforms by various RTOs.[38] Because these reform measures have only recently been implemented, TAPS urges the Commission to allow them some time to bear fruit before assessing their effectiveness and whether additional reform is required in RTO areas.

On the other hand, the Commission's queue reform efforts have to date focused solely on RTO regions, ignoring the vast portions of the country that are not covered by an RTO. The Commission should not assume that the interconnection queue is working in non-RTO areas. For example, the Navajo Tribal Utility Authority ("NTUA") has experienced problems with lengthy transmission planning queues at individual utilities in the desert Southwest. The queues are clogged with projects for which developers have not acquired rights to the land in question. NTUA has been working with partners to develop an 85 MW wind project (expandable in the second phase by up to 200 MW) at Boquillas Ranch in Arizona (to interconnect with an Arizona Public Service ("APS") line to the Western Area Power Administration ("Western") transmission system) and on

---

[37] *Interconnection Queuing Practices*, 122 F.E.R.C. ¶ 61,252, P 3 (2008).

[38] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 124 F.E.R.C. ¶ 61,183 (2008), *on reh'g*, 127 F.E.R.C. ¶ 61,294 (2009); *Cal. Indep. Sys. Operator Corp.*, 124 F.E.R.C. ¶ 61,292, P 58 (2008), *reh'g denied*, 127 F.E.R.C. ¶ 61,177 (2009); *Sw. Power Pool*, 128 F.E.R.C. ¶ 61,114 (2009).

another wind project at Gray Mountain that could represent up to 500 MW, that would interconnect directly into the Western system. Renewable generation projects are time sensitive, due to the need for qualify for various incentives by certain dates, but it has been difficult for NTUA to obtain an appointment to speak with the Western transmission planners due to their workload addressing projects ahead of NTUA's in the queue.[39] This is true even though many of those projects have not acquired land rights and may have no prospect of doing so. NTUA has encountered similar delays attempting to coordinate with APS transmission planners and with those at Public Service Company of New Mexico, who are also trying to process lengthy interconnection queues.

The absence of meaningful minimum requirements for a project to join the queue, such as those adopted by RTOs,[40] allows gamesmanship by potential competitors manipulating the queue to crowd out viable renewable projects. Thus, TAPS urges the Commission to promptly take steps to address queue problems in non-RTO regions.

Finally, TAPS notes that the proactive integrated planning undertaken by CapX, which focuses on providing the infrastructure required for a range of generation expansion scenarios, should facilitate more rapid movement of projects through the queue, and thereby interconnection of needed generation.

- *Should there be consistency in the way transmission providers treat demand resources, such as demand response, energy efficiency and distributed storage, in the transmission planning process? Are there preferred methods of modeling or otherwise accounting for demand resources in the planning process? Does the planning process*

---

[39] Western has a non-jurisdictional safe harbor OATT, *available at* http://www.wapa.gov/transmission/oatt.htm.

[40] *E.g., Cal. Indep. Sys. Operator Corp.*, 124 F.E.R.C. ¶ 61,292, P 58 ("The Commission accepts the CAISO proposal to increase the amount of its study and site exclusivity deposit requirements as reformatory measures necessary for the CAISO to facilitate the interconnection of viable generation, and to reduce the opportunity for speculative projects to enter and remain in its queue.").

investigate transmission needs at fine enough granularity to identify beneficial demand resource projects?

In concept, demand resources should be treated comparably to supply resources in the planning process. At the practical level, it may be challenging to figure out what is comparable in this context.

To some extent, demand response gets factored into the load projections used for planning purposes. For example, an LSE's peak load may be reduced to reflect the reductions achieved by interrupting load as authorized by contract with the LSE.

Demand resources also are reflected in planned generation projects. For example, ISO-New England includes demand response in its forward capacity markets, and has nearly as much new demand response (1,636 MW) committed for the 2010-2011 and 2011-2012 period as new supply resources (1,783 MW).[41] This reliance on demand response is reflected in planned generation additions (or reduction thereof) and transmission planning.

But it remains challenging to more broadly integrate into the planning process the type of market-driven demand response the Commission is seeking to foster through initiatives such as the demand response aggregation bid acceptance requirements imposed by Order No. 719.[42] Simply put, forecasting the behavior of individual retail customers

---

[41] *See* Henry Yoshimura, Update on Demand Resource Participation in New England's Forward Capacity Market 5, 7 (Feb. 17, 2008), *available at* http://www.narucmeetings.org/Presentations/FCM%20ISO%20New%20England%20NARUC-FERC%202008-Final.ppt#304,1, *and* Roger Bacon, Second Forward Capacity Auction (FCA#2) Results Summary 5 (Jan. 21, 2009), *available at* http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/jan212009/fca2_results.pdf.

[42] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), III F.E.R.C. Stat. & Regs. ¶ 31,281, *on reh'g*, Order No. 719-A, 74 Fed. Reg. 37,776 (July 29, 2009), III F.E.R.C. Stat. & Regs. ¶ 31,292, *reh'g granted*, No. RM07-19-002 (FERC Sept. 16, 2009).

in response to wholesale market prices is difficult.[43] Further, at this stage of its development, retail customer demand response not otherwise reflected in load forecasts may be too small or too dispersed to be a significant factor in transmission planning.

- *Are existing dispute resolution procedures in transmission provider tariffs adequate to address disputes that arise in the planning process?*

No. Existing tariff dispute resolution processes are focused on disputes between a transmission customer and the TP under that tariff. *See pro forma* OATT § 12. A customer's ability to protest the filing of a proposed transmission service agreement or interconnection agreement provides a vehicle to address certain issues that arise in the transmission or interconnection request-specific planning process. However, notwithstanding Order 890's provision for dispute resolution of planning issues (*see* Order 890, P 501), it's not clear how effective that avenue is, given Order 890's placement of ultimate responsibility for planning and construction in the TP's hands. *See* Order 890, P 454; Order 890-A, P 178. Further, tariff dispute resolution provisions will have limited usefulness if the planning dispute is between multiple transmission providers.

IV. COMMENTS ON COST ALLOCATION

A. Overview as to Cost Allocation

TAPS agrees that cost allocation can be a significant a barrier to getting needed transmission built and concurs in the Commission's summary of the serious challenges associated with addressing cost allocation. As accurately described in the Notice, cost

---

[43] Moreover, the individual attributes of each interruptible load contract must be taken into account (e.g., whether load may be interrupted only in response to generation needs, not transmission needs).

allocation is a very difficult problem, even within RTOs. Indeed, in conditionally accepting major amendments to the Midwest ISO's cost allocation for generator interconnection-related network upgrades, subject to the Midwest ISO's submission of a long-term solution by July 15, 2010, the Commission "recognize[d] that cost allocation is one of the most difficult and contentious issues facing the Midwest ISO region at this time."[44] In fact, the issue was so contentious that two of the Midwest ISO's TOs had stated an intent to withdraw from the RTO as a result of the current generator interconnection cost allocation methodology, and the Midwest ISO and its TOs had urged adoption of the amended cost allocation as an interim measure to preserve the Midwest ISO footprint pending development of the longer term solution.[45]

It is very challenging to figure out what is a "just and reasonable" allocation of long-lived transmission facilities, whose use and beneficiaries change over the life of the facilities, with changes in grid topography and usage over time. General allocation rules have the potential for unintended consequences,[46] but case-by-case allocation of each upgrade is impractical and unworkable if the aim is to support the timely construction of needed transmission upgrades.

The pending proposals for crisscrossing the nation with 765 kV overlay lines have greatly complicated the already very difficult cost allocation debate. The staggering cost of implementing these proposals enormously raises the stakes, and makes compromise much harder. While these proposals cannot be ignored, the Commission's consideration

---

[44] *Midwest Indep. Transmission Sys. Operator, Inc*., 129 F.E.R.C. ¶ 61,060, P 2 (2009).

[45] *Id.* P 10.

[46] *See, e.g.*, MISO's August 29 Informational Compliance Filing at 5, 10-12 (describing the inability to get any projects to qualify as Regionally Beneficial).

of cost allocation should not assume that the 765 kV overlay is appropriate and should get built; and the existence of 765 kV line proposals should not drive the cost allocation principles otherwise applicable to transmission upgrades. According to NERC's 2009 Scenario Reliability Assessment (at 2) only one region, Reliability First Corporation,[47]

> plans to rely on imports from other Regions through transmission proposed in the [Joint Coordinated Systems Plan], the remaining Regions plan to rely on resources within the Region to meet scenario targets in this assessment. This indicates there are multiple approaches to meeting the renewable energy scenario goal: while the JCSP propos[ed] to construct renewable resources in the mid-section of the Untied States and transfer a portion of the energy to the Northeast via bulk transmission, [Northeast Power Coordinating Council] has proposed to meet renewable energy targets using resources within the Region.

While TAPS has supported regional cost allocation of major backbone facilities to spread the cost burden and match cost responsibility to the regional benefits that will be realized,[48] TAPS strongly believes that interconnection-wide cost allocation is *not* the answer. It assaults any sense of fairness to saddle Maine with the cost of transmission facilities in the Dakotas, especially if New England is seeking to develop more local

---

[47] *Available at* http://www.nerc.com/files/2009_Scenario_Assessment.pdf.

[48] *See* TAPS White Paper at 4, 19-20. Indeed, the significant transmission investments that have been and are being made in New England are a testament to the success of this approach. "Since 2000, ISO New England's regional system planning process has identified the need for approximately $8 billion in transmission investment, prompting significant transmission development in each of the New England States. More than $1 billion in transmission investment has occurred over the past eight years, and projects estimated at approximately $7 billion in investment are in various stages of development, planning, or construction." ISO New England, Regional System Planning Spurs Major Investment in New England's Transmission System 2 (2008), *available at* http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2008/rsp_ne.pdf.

renewable resources. Nor would allocation of those costs to Florida stand up to scrutiny under the Federal Power Act.[49]

Nor is the answer participant funding, which forces one or more market participants to bear the cost of network upgrades that provide broad benefits that change over time in a dynamic AC grid, creating enormous free-rider effects especially because of the inherent lumpiness of efficient upgrades to the grid.[50] Because of these qualities, the Commission has long recognized that roll-in of network upgrades is appropriate.[51] Rolled-in treatment of most upgrades is essential to get the highways of commerce in this industry in place, so that all loads can have reasonable access to the competitive market.

In contrast, participant funding is a recipe for a weak grid, where virtually nothing gets built. This fundamental deficiency is perhaps most evident in the transmission system of Entergy, a prominent proponent of participant funding. When TDUs seek to add new network resources (or to become network customers and add resources), they are faced with claims for hundreds of millions of dollars in upgrades to fix problems on the Entergy grid that have existed for years due to Entergy's grid starvation policy.[52]

TAPS urges the Commission to take a more active role than it has to date in guiding cost allocation policy, especially for transmission facilities that extend beyond a single transmission provider. TAPS suggests that the Commission, through rulemaking, establish clear cost allocation principles for new transmission in approved regional and

---

[49] *See Ill. Commerce Comm'n. v. FERC*, 576 F.3d 470 (7th Cir. 2009).

[50] *See* TAPS White Paper at 8-9.

[51] *See, e.g, Ne. Tex. Elec. Coop., Inc.*, Op. No. 474, 108 F.E.R.C. ¶ 61,084 (2004); *Pub. Serv. Co. of Colo.*, 62 F.E.R.C. ¶ 61,013 at 61,062 (1993); *Midwest Indep. Transmission Sys. Operator, Inc.*, 98 F.E.R.C. ¶ 61,141, at 61,412 (2002); *W. Mass. Elec. Co. v. FERC*, 165 F.3d 922 (D.C. Cir. 1999).

[52] *See, e.g.*, Entergy Transcript at 163-164.

interregional plans. As discussed below, it's also time for the Commission to directly address and provide for rates that cross TP boundaries. FERC's rulemaking should remove impediments to the construction of needed new generation and give appropriate recognition to the multiple and changing benefits that will be provided over the life of major new transmission lines. But a region, or sub-region, should not be assigned costs that are substantially disproportionate to reasonably anticipated benefits.

B. Responses to Commission Cost Allocation Questions

- *To the extent that a lack of up-front certainty about cost allocation is inhibiting transmission development, describe the relative impact of this concern on specific projects and as it relates to other impediments to development.*

Certainty is very important to facilitating needed transmission construction. In general, lack of certainty as to cost allocation has a chilling effect on transmission proposals. Case-by-case determination as to the allocation of each facility would be unworkable and would stymie needed transmission development.

That being said, certainty will only support transmission construction if the cost allocation being locked in will be considered fair and will support needed grid expansion. For example, certainty that the cost allocation for transmission upgrades would be governed by participant funding would ensure that little or nothing gets built.[53]

- *Should processes be established to help stakeholders address cost allocation matters over larger geographic regions? What is an appropriate scope for those regions? Should they align with the regions for which planning is conducted?*

---

[53] *See, e.g*, Entergy Transcript at 42 ("The first two years of ICT operations have clearly shown that the Entergy/ICT's participant funding approach has not resulted in any significant transmission construction in Entergy's footprint.").

After recognizing that "the manner in which the costs of new transmission are allocated is critical to the development of new infrastructure," the Commission, in Order 890, required TPs to "address the allocation of costs of new facilities." Order 890, P 557. Order 890's cost allocation principle was aimed at "projects that do not fit under the existing structure, such as regional projects involving several transmission owners or economic projects that are identified through the study process described above, rather than through individual requests for service." *Id.* P 558. Order 890 expressly allows regional flexibility, while providing some overall guidance, stating that it will balance the following factors (*id.* P 559):

> First, we consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them. Second, we consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, we consider whether the proposal is generally supported by state authorities and participants across the region.

While some Order 890 compliance filings made progress on inter-TP cost allocation issues, others did not, but were still found compliant.[54] Also, while in some

---

[54] *See, e.g., Sw. Power Admin.*, 127 F.E.R.C. ¶ 61,173, P 53 (2009) (emphasis added) (accepting as Order 890-compliant a filing that left cost allocation to SWPA's discretion: "We find that Southwestern has addressed the concerns of the Southwestern Planning Order regarding the cost allocation principle of Order No. 890. Southwestern has revised Attachment O to state clearly that its participation in the SPP cost allocation methodology, and in particular the allocation of costs associated with economic projects, will be governed by the SPP/Southwestern Agreement. *That agreement provides that SPP will propose the allocation of costs associated with upgrades within the SPP footprint, including on the Southwestern system, and that Southwestern will respond to SPP as to the allocation it accepts.*"). *See also Midwest Indep. Transmission Sys. Operator, Inc.*, 123 F.E.R.C. ¶ 61,164, P 77 (accepting MISO's Order 890 transmission planning cost allocation provisions despite the fact that they did not address allocating costs of inter-RTO projects, but instead accepting MISO's statement "that it is working with PJM to address cross-border cost allocation for network upgrades.").

instances the cost allocation methodology was developed through a regional process where TDUs at least had input,[55] that is not universally the case.

Thus, the Order 890 compliance filings are unlikely to provide a sufficiently robust basis for cost allocation beyond individual TPs. One way to move forward would be through requiring open and inclusive regional/inter-regional processes (in which TDUs have a real voice) to address cost allocation, but TAPS suggests that the Commission first develop by rulemaking cost allocation principles that must be satisfied. TAPS also suggests that an important backdrop for such efforts would be recognition by the Commission, as part of that rulemaking, of its authority to require cost sharing beyond the borders of individual transmission providers, as more fully discussed below.

- *Are there regional cost allocation methodologies outside RTOs, and broader regional cost allocation within RTOs, that should be considered or established? If so, how should this be done?*

TAPS urges the Commission to address allocation of costs of projects that go beyond existing boundaries of an RTO or individual TP where the grid is integrated. In particular, the Commission should recognize and exercise its long-established authority to order joint, non-pancaked rates where transmission systems are integrated. *Fort Pierce Utils. Auth. v. FERC*, 730 F.2d 778, 783-85 (D.C. Cir. 1984).[56] Many, if not all, regions would meet that test. The addition of inter-regional transmission facilities would clearly strengthen the argument in favor of a finding of integration. Further, the fact that TDU

---

[55] *See Tampa Elec. Co.*, 124 F.E.R.C. ¶ 61,026, P 7 (2008).

[56] *See also Permian Basin Area Rate Cases*, 390 U.S. 747, 776-77 (1968) (Supreme Court approving Commission's use of area rates, noting that "the width of administrative authority must be measured in part by the purposes for which it was conferred") (internal citations omitted).

loads and resources often span multiple transmission systems supports a finding of integration and signals the need for joint rates.

For non-RTO regions, requiring joint rates would provide a vehicle to deal with cost allocation of regional upgrades that extend or have impacts beyond an individual TP's transmission system, and may reduce the disincentive for formation of new and expanded RTOs. It would also eliminate the rate pancaking that the Commission has long recognized as a competitive barrier.[57]

Moving toward joint rates that extend beyond an RTO will facilitate allocation of costs of inter-regional facilities, as well as improve cost allocation within an RTO by limiting the ability of TOs to exert influence over RTO cost allocation decisions by threatening to withdraw, and diminish the perceived advantages of remaining outside an RTO's boundaries.

In short, the authority to require joint rates provides the Commission a tool to address inter-TP cost allocation and advance other pro-competitive policy objectives. A joint rate that crosses existing TP or RTO boundaries can reflect a range of rate designs, including the TRANSLink "highway/byway" rate design discussed below.

- *Should each transmission provider hold an open season solicitation of interest for needed transmission projects identified through the transmission planning process in order to assist in cost allocation determinations?*

---

[57] *See* Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809, 817 (Jan. 6, 2000), [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,089, at 31,004, *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,092, *appeal dismissed for want of standing sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) ("[T]he NOPR explained that pancaked transmission rates (where a separate access charge is assessed every time the transaction contract path crosses the boundary of another transmission owner) restrict the size of regional power markets. The Commission added that the balkanization of electricity markets hurts consumers who pay higher transmission rates and have access to fewer generation options.").

As discussed above with regard to planning for merchant transmission, TAPS is skeptical about market-based approaches to transmission. We also believe that establishing cost allocations on a case-by-case basis for each individual facility or upgrade would foment controversy, cause delay, create additional uncertainty and discourage needed transmission construction. As discussed below, TAPS has long opposed participant funding of network upgrades as inappropriate and unjust on an integrated AC grid, and counterproductive to the Commission's stated intention of promoting needed grid investment. Such approaches are also fundamentally at odds with the Commission's traditional recognition of the grid as an integrated network.

TAPS recognizes, however, that open seasons can play a useful role for some purposes and in some instances. For example, as discussed above, TAPS supports use of an open season process for joint ownership opportunities, particularly where a TDU will be required to bear the cost of the facility, for TDUs that are located in or provide service to customers in the state(s) (or a broader region where an RTO or ISO so provides) where the project is or will be sited. Some form of open season/solicitation of interest can also play a useful role in the planning process in assessing need for a facility.

Lastly, there may be a role for subscription in the case of renewable "generator leads," where payment for a share of the transmission facilities assures the transmission customer rights to the connected renewable generation. Such treatment would be comparable to the treatment of the non-network interconnection facilities among joint owners of the associated generator, and may make sense given the need for assured access to very remote renewable generation, *e.g.*, to satisfy renewable portfolio requirements.

- *How can the customers that benefit from a particular facility be determined? Is there a preferred method? Should the method vary depending on the nature of the facility?*

- *Should costs for base upgrades needed for existing reliability or economics be allocated differently than excess capacity expected to be needed for later-developed resources? Should the allocation of costs for certain projects take into account the risk of under-subscribed "right sized" lines? If so, how should costs be re-allocated over time as such lines become subscribed by new customers?*

- *Should cost allocation mechanisms continue to differ based on whether a project is deemed necessary based on reliability and adherence to approved reliability standards versus economic considerations?*

- *Should the determination of beneficiaries of a transmission facility include generators as well as loads?*

- *Should benefits be recalculated over time? Would recalculations negatively affect usage decisions?*

- *How should non-quantifiable costs or benefits be identified, factored in or otherwise weighted?*

As discussed above with regard to planning, TAPS does not believe the bright line economic/reliability distinction is a viable means to determine which facilities are constructed or how costs are allocated. Virtually all transmission upgrades provide both reliability and economic benefits, and so-called "economic" upgrades may be essential reliability facilities in the long-term. Reliability projects are simply special cases of economic projects where the costs of not proceeding take the form of bad service and/or the potential for violation of reliability standards.[58] Moreover, if the Commission were to narrowly focus on reliability upgrades, it would fail to fulfill its Congressionally

[58] The most common major transmission system expansion projects involve upgrades to accommodate the construction of key baseload generation, tying the generator to major load centers. Trying to characterize these facilities as either "reliability" or "economic" upgrades makes no sense. They are obviously both.

mandated grid expansion responsibilities. *See, e.g.*, FPA Sections 216,[59] 217(b)(4),[60] and 219.[61]

Cost allocation involves consideration of cost causation, but determining such causation is challenging on an integrated AC grid where beneficiaries are hard to identify and can change dramatically over time with alterations in grid topography and power supply economics. And many benefits of very important network upgrades are difficult to quantify, such as enhanced reliability, local area resource reserve needs, optionality and flexibility. By increasing consumer choice, a robust grid can help reduce volatility and buffer the effects of unpredicted changes. Improved transmission allows LSEs to capitalize on unanticipated opportunities and avoid price spikes, and it provides a hedge against major disruption from facility outages. A stronger grid will also expand the areas suitable for siting new generation, provide enhanced access to renewable generation, make maintenance easier and less costly (since the facility outages needed for maintenance or upgrades will not threaten the provision of reliable service) and reduce electrical losses and congestion. All these benefits are hard to quantify but critical to a robust, reliable grid.

While the Seventh Circuit in *Illinois Commerce Commission v. FERC* recently remanded the Commission's postage stamp rate for 500 kV lines in PJM as unsupported, the decision allows the Commission considerable room to support regional cost allocations where warranted. The Court instructed:

---

[59] 16 U.S.C. § 824p.

[60] 16 U.S.C. § 824q(b)(4).

[61] 16 U.S.C. § 824s.

> FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members.

576 F.3d at 476. The Court cautioned, however, that it was not demanding precision.

> We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. *Midwest ISO Transmission Owners v. FERC*, *supra*, 373 F.3d at 1369 ("we have never required a ratemaking agency to allocate costs with exacting precision") . . . If it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. . . . But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."

Id. at 477 (most citations omitted). The Seventh Circuit's instruction is thus consistent with TAPS' view, as expressed in the Cost Allocation Overview section above, that the Commission should authorize cost allocation methodologies that support needed transmission investment and give appropriate recognition to the multiple and changing benefits that will be provided over the life of major new transmission lines, but avoid assignment to a region, or sub-region, of costs that are substantially disproportionate to reasonably-anticipated benefits.

TAPS generally agrees with the Commission's recent guidance on cost allocation.[62]

---

[62] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,060, PP 53-56 (footnotes omitted).

> . . . As the Commission noted in Order No. 2003-A, the Commission has long held that the transmission system is a cohesive, integrated network that operates as a single piece of equipment, and that network facilities are not "sole use" facilities but facilities that benefit all transmission customers. The Commission has reasoned that, even if a customer can be said to have caused the addition of a grid facility, the addition represents a system expansion used by and benefiting all users due to the integrated nature of the grid. For this reason, the Commission has consistently priced the transmission service of a non-RTO/ISO transmission provider based on the cost of its grid as a whole, and has rejected proposals to directly assign the cost of network upgrades.
>
> Even where the Commission has permitted departures from this precedent in ISO and RTO systems, it has consistently found that cost allocation for generator interconnection-related network upgrades must strike an appropriate balance between the entity that "caused" the need for an upgrade (*i.e.*, by deciding to interconnect a new generator) and the larger set of entities that will actually benefit from that upgrade.
>
> We agree with commenters' arguments that additional, broad-ranging benefits can be associated with both the interconnecting generator and the network upgrades that are triggered by its interconnection. Depending on the particular characteristics of the generator and network upgrades in question, these broad-ranging benefits could include those identified by commenters.
>
> Accordingly, the Commission believes that cost allocation proposals for interconnection-related upgrades should pay attention to cost-causation principles and to identifying the full array of benefits to generators, load, and other entities in the region from enhanced transmission infrastructure.

While identification of benefits needs to go beyond the narrow energy production cost savings typically modeled for such quantifications, the benefits used to support cost allocation should not include generalized social or environmental benefits. Inclusion of such benefits as justification for transmission cost allocation would be unlikely to achieve acceptance because it would be viewed as a cover for assigning costs to those who receive little or no benefits. On the other hand, an LSE's ability to meet its renewable portfolio requirements certainly merits consideration as part of the generation projections and benefits of a proposed transmission project.

As to the Commission's question regarding recalculation of benefits over time, the appropriateness of such a recalculation may depend on the circumstances (*e.g.*, reliance interests in the initial structuring, exposure to financing risk).

While identification of an articulable connection to benefits is necessary to justify cost allocations, adoption of a formulaic methodology is needed to avoid the delay and uncertainty of a case-by-case approach. TAPS suggests that some form of the TRANSLink "highway/byway" approach that TAPS has long advocated[63] is worthy of consideration. The TRANSLink rate design spreads regionally the cost of highway facilities and assigns costs for the local area grid "byway" facilities to both load and generation. This method thus addresses the equities of the "export zone" issue—customers in one transmission system unfairly bearing costs of upgrades designed to serve load outside that system—while fairly sharing the costs consistent with cost causation and the regional benefits obtained. Thus, it more equitably spreads the cost of regionally-beneficial upgrades and is better tailored to getting transmission built.[64] Allocation of some costs to generators provides a useful price signal where generation is

---

[63] It is described in the Commission's April 25, 2002 Order in *TRANSLink Transmission Co., L.L.C.*, 99 F.E.R.C. ¶ 61,106, at 61,465-68, *order on reh'g*, 101 F.E.R.C. ¶ 61,140, and its December 19, 2002 Order in *TRANSLink Development Co., LLC,* 101 F.E.R.C. ¶ 61,316 at PP 15-24, *on reh'g*, 103 F.E.R.C. ¶ 61,208 (2003). *See also* TRANSLink's SMD Initial Comments at 30-31 & n.47, Docket No. RM01-12 (Nov. 15, 2002), *available at* eLibrary Accession No. 20021115-5470.

[64] *See* TAPS White Paper at 19-20.

used to meet remote loads, gives generators a better price signal for deciding where to locate and helps address import/export zone equities.[65]

Because it reflects a middle ground between “license plate” and “postage stamp” rates, and provides for generation sharing in the billing determinants to address “export zone” issues, a TRANSLink “highway/byway” approach may have promise for breaking the logjam in RTOs and other areas where regional/interregional cost allocation remains a serious problem. But the devil is in the details (*i.e.*, which facilities are “highway” versus “byway”), and may be different in different regions.

Finally, TAPS cautions that in moving forward to address cost allocation, the Commission should not upset the progress that has been made in some regions, and require a “fix” to something that is not “broken.”

[65] In areas with LMP, however, care must be taken to assure that any transmission charges assigned to generators do not simply result in increased LMPs in the areas where the generators are located. Increasing electricity prices within an “export zone” in order to fund transmission facilities to move electricity *out* of the export zone sends the wrong price signal and places an unjust and unreasonable burden on consumers within the export zone. It may be possible to avoid this problem by requiring that any transmission charges assigned to generators take the form of access fees (*i.e.*, based on MW of capacity), rather than usage charges (*i.e.*, based on the MWhs of energy generated).

Respectfully submitted,

/s/ Cynthia S. Bogorad

Robert C. McDiarmid
Cynthia S. Bogorad
William S. Huang
J.S. Gebhart

Attorneys for
Transmission Access Policy Study Group

Law Offices of:
Spiegel & McDiarmid LLP
1333 New Hampshire Avenue, NW
Washington, DC 20036
(202) 879-4000

November 23, 2009

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated on this 23rd day of November, 2009.

/s/ William S. Huang

William S. Huang

Law Offices of:
Spiegel & McDiarmid LLP
1333 New Hampshire Avenue, NW
Washington, DC 20036
(202) 879-4000