

The Brattle Group

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December 18, 2009

Secretary
Federal Energy Regulatory Commission
Room 1 A
888 First Street, NE
Washington, DC 20426

To Whom It May Concern:

Enclosed are comments for Docket No. AD09-8-000 in response to the October 8, 2009 notice requesting stakeholders' comments on the transmission planning process under Order No. 890.

If you have any questions, please feel free to contact me.

Sincerely,

Marianne Gray

Marianne Gray
Executive Assistant

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**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Transmission Planning Processes)	Docket No. AD09-8-000
Under Order No. 890 – Notice of)	
Request for Comments)	

**COMMENTS OF
PETER FOX-PENNER, JOHANNES PFEIFENBERGER, AND DELPHINE HOU¹**

Pursuant to the October 8, 2009 Notice of Request for Comments (“Notice”) of the Federal Energy Regulatory Commission (“Commission” or “FERC”), we are pleased to submit comments in the above-referenced docket. These comments represent only the views of the undersigned and are not the views of *The Brattle Group*, its clients, or any other organizations with whom we are associated. We have included in Attachment A our presentation *Transmission Investment Needs and Cost Allocation: New Challenges and Models* which was presented to members of the FERC on December 1, 2009. The presentation in Attachment A directly addresses the topics discussed in our comments and provides additional background information on these subject matters.

I. INTRODUCTION AND OVERVIEW

Despite the successful increase in transmission investment levels over the last several years, significant barriers remain to investment in regional (*i.e.*, multi-state and/or multi-utility)²

¹ Dr. Fox-Penner is a Principal and Chairman Emeritus, Mr. Pfeifenberger is a Principal and Practice Area Leader, and Ms. Hou is an Associate of *The Brattle Group* (www.Brattle.com). The views expressed herein are the authors’ own.

² We emphasize that our comments often will not generally apply to projects undertaken by incumbent transmission owners or projects that are within a single state.

transmission projects. While many regional transmission projects are being planned or proposed, cost allocation has become the most significant barrier to such investments. Our presentation provided in Attachment A documents these difficulties, provides examples and case studies of promising new cost allocation approaches, and suggests some policy directions. Our comments in this filing present policy recommendations for a workable regional planning and cost allocation framework that we believe the Commission could implement through a rulemaking.

Our detailed recommendations, in Section III below, are based on our vision of a more effective regional grid expansion process that includes planning, siting, and cost allocation, with an appropriate balancing of stakeholder input, efficiency, and fairness. In brief, our vision is that subregional transmission planning groups (geographically covering RTOs/ISOs, portions thereof, or other multi-state regions) be required to produce triennial grid plans that meet all applicable reliability standards as well as federal and state energy policy goals, use a fully integrated economic planning process, and include binding cost allocation proposals for all significant additions. These voluntary “subregional planning entities”—many of which would likely be based on existing RTO or subregional planning groups—would include state-level representation able to commit to the grid plans and cost allocation proposals that the group files with the Commission. The Commission would accept these plans and cost allocations as presumptively yielding just and reasonable rates unless stakeholders can prove otherwise. We also recommend that the Commission develop a framework that would be applied if the subregional planning groups were unable to resolve cost allocation.

We stress that this vision does not mean either abandoning the use of wholesale power markets or forcing any other rearrangements in vertical relationships within the industry. While

some industry observers have argued that processes involving centralized planning efforts inherently impede markets, in this instance we respectfully disagree. The transmission infrastructure is a highly interdependent system that conveys many types of quasi-public and public benefits to every electricity user and the U.S. economy as a whole. One of these benefits is enabling wholesale power markets, which cannot function properly without adequate transmission. Planning is and has always been the first step in creating or expanding an infrastructure critical to markets, as well as to continued affordable and reliable service to vertically integrated utilities. For regional transmission expansion, this planning effort also needs to coincide with cost allocation and siting.

We are aware that Congress is considering alterations to the Commission's transmission planning and/or ratemaking authority. We believe that our proposal is useful under current authority but also highly adaptable to nearly any of the alterations of federal policy we have heard discussed. As a result, we think it is a useful path forward, even in a somewhat uncertain transmission policy environment.

II. DEFICIENCIES IN CURRENT RTO AND OTHER REGIONAL PLANNING AND COST ALLOCATION PROCESSES

The pace of new transmission investments has been accelerating over the last several years. Transmission investment by U.S. investor-owned utilities has increased from approximately \$2 billion per year in the 1980s and 1990s, to approximately \$4 billion per year during 2003-05, exceeding \$6 billion per year in 2006 and 2007, and reaching a level of more than \$8 billion in 2008. NERC projects transmission additions to triple, from an average of about 1,000 miles per year for the period 2000 to 2008, to 3,100 miles/year from 2009 through

2018. These trends clearly document that existing transmission policies—including planning, siting, and cost allocation processes—have succeeded in substantially increasing the pace of investment in recent years.

However, the majority of investments to date consist of traditional single-utility or single-state projects built to satisfy reliability needs, RTO-level reliability projects, or investments to interconnect individual generating units. At present, factors such as state renewable portfolio standards (“RPSs”), a potential federal RPS, and probable climate goals are now placing an unprecedented amount of additional transmission proposals on the drawing boards. We have identified almost 90 new planned and conceptual projects across the U.S., each greater than \$100 million, which in total represent approximately \$120 billion in new investment. Though some of these projects specifically address reliability concerns, many are large multi-utility, multi-state, and *multi-purpose* projects that may reinforce reliability but also address a number of other needs, such as interconnecting significant amounts of renewables, lowering production costs, and reducing congestion. While not all of the proposed projects will come to fruition for a variety of reasons, cost allocation is the single most significant barrier.

For many of the proposed regional transmission projects—in particular “economic” projects, renewable integration projects, high-voltage overlay projects, and multi-purpose projects—cost allocation is largely unresolved except in single-state RTOs such as CAISO and ERCOT. This is because the interaction between planning, cost allocation, and permitting creates a nearly insurmountable hurdle for many regional projects: permitting is often focused on the balance of costs and benefits to *each permitting state*, which in turn depends in part on the costs allocated to that state. Moreover, “beneficiary pays” frameworks can create incentives to

understate or omit benefits in order to avoid being allocated a larger share of the costs. The result is that projects that could be beneficial to a region may not appear as such based on the benefits identified by the existing process. This particular problem is exacerbated by the narrow definition of “economic benefits” used by RTOs in the Eastern Interconnect for their project evaluations. As a result of all these factors, there has not been a single sizable “economic” project approved in the ISO New England, Midwest ISO, New York ISO, or the PJM Interconnection.

It is difficult for RTOs, transmission owners (“TOs”), and market participants in the various regions to move beyond current approaches. This is reflected in comments PJM has made in its filing with the Commission:

[T]he planning process is guided by the very strict planning criteria set forth in the PJM Tariff. In the area of economic planning, the Commission rejected PJM’s original approach for a broader set of planning criteria and required strict criteria by way of a formulaic approach to define what can be approved as an economic project under the [Regional Transmission Expansion Planning] process. Although such an approach provided a clearer “bright line” by which the formula presumptively identifies which projects should be included in the [Regional Transmission Expansion Planning] and prevents the opportunity for undue discrimination, PJM believes that, as changes in state and national policy have evolved, that formulaic approach has led to certain unintended consequences that can limit certain kinds of desired future grid expansion.³

While there are several promising efforts underway—such as the highway/byway cost allocation methodology developed by the Regional State Committee (“RSC”) of the Southwest Power Pool (“SPP”), the Organization of Midwest ISO States’ (“OMS”) efforts to develop an injection-withdrawal methodology through its Cost Allocation and Regional Planning (“CARP”) process, or the Cost Allocation Committee’s efforts within the Northern Tier Transmission

³ PJM Interconnection, “PJM’s Regional Transmission Expansion Planning Process,” FERC Technical Conference on Transmission Planning Process Under Order No. 890, Docket No. AD09-8-000, September 21, 2009, page 6.

Group—cost allocation remains a significant barrier. This has slowed transmission development for many proposed projects, including those needed for large-scale renewable integration.

State commissions also often lack the jurisdiction and/or the political support to mandate or enforce regional plans and cost allocation agreements, but their responsibilities give them a critical, central role in the successful development of sound regional solutions. Our recommendation focuses on a subregional planning and cost allocation process that strongly relies on the direct involvement of and support by state commissions and other state policy makers.

III. SUGGESTED FRAMEWORK FOR AN IMPROVED REGIONAL TRANSMISSION PLANNING AND COST ALLOCATION PROCESS

In this section we discuss a proposed process for subregional transmission planning and cost allocation that we believe the Commission could implement through a rulemaking. While fashioning this process, our objectives have been to:

- Meet national energy and environmental policy objectives, including providing transmission needed to meet renewable energy requirements and national climate policies;
- Allow for varying state and regional energy, environmental, and economic development objectives;
- Maintain a reliable transmission system able to provide support to wholesale markets and continued service to all segments of the industry; and
- Operate within the Commission’s current authority.

The core elements of our proposed process are that (a) subregional planning entities (“SPEs”) that are larger than single utilities or states should be invited to form voluntarily; (b) SPEs should use open and transparent processes to create combined subregional plans and

associated near-term cost allocation commitments⁴ for the subregional grid within a specific timetable and planning cycle; and (c) the Commission should accept these plans and cost allocations as presumptively yielding just and reasonable rates unless stakeholders can prove otherwise. Under existing Commission authority, the process and planning cycle may have to be voluntary.

We call the core organizational unit an SPE in order to emphasize that the planning areas may be smaller than what industry stakeholders now call “regions.” For example, many industry participants and analysts refer to the Western Electricity Coordinating Council (“WECC”) as a single region. We do not suggest that planning units be locked into any such current definitions of regions, but rather to leave the choice of SPE boundaries to the affected states. More specifically, we propose that the states in every region of the U.S. pick one or more SPEs to become a member of and that this decision be left to them. The boundaries need not be along states lines and overlaps (*i.e.*, states joining more than one SPE) are acceptable and perhaps even desirable. The Commission should get involved in selecting the boundaries of SPEs only upon the petition of the affected states that they cannot agree on such boundaries by the date that would be specified within the rule.

As we envision it, the SPEs’ charge would be to develop twenty-year grid expansion plans that meet a set of policy and process objectives. As policy objectives, we propose that each plan demonstrate that it meets: (1) national energy policy objectives;⁵ (2) energy, economic,

⁴ The cost allocation portion of the plan should apply only to facilities that will be built within the next three to five years, or alternative short-run window. Allocating the costs of facilities built outside the near-term time frame can occur in later planning cycles.

⁵ We suggest that the Department of Energy, which represents the nation before the Commission, be charged with articulating these policies and commenting on compliance with them in the SPE plans.

and environmental policies of the SPE states;⁶ and (3) reliability and cyber-security requirements set out in all Commission and other applicable standards. A plan should also reasonably be expected to meet these economic policy and reliability objectives at lower costs or higher net benefits to the subregion in comparison to alternatives. As discussed further below, all transmission-related benefits should be considered (at least qualitatively), including broader regional benefits for any parts of the SPE plan that involve coordination and cost sharing with other subregions.

We recognize that the formulation of SPE plans of this nature is an extensive undertaking that requires substantial analytical efforts involving many assumptions. At the same time, many utilities of all types, RTOs, ISOs, and other entities already plan and expand their system using processes of this nature, involving the same analytical techniques and assumptions as SPE plans will require. In addition, many state public service commissions utilize similar planning efforts and are familiar with how they are properly conducted.

As long as it complies with planning process requirements, an SPE could utilize any qualified agent it chooses to produce the plan. It may create a planning institute or consortium that does not yet exist, use an existing regional or subregional association or group, coordinate with an ISO or RTO, or develop some other approach. In fact leveraging existing RTO-level or subregional planning groups would likely be desirable. In addition to the existing RTO-level planning functions and groups of state regulators such as the OMS in the Midwest ISO or the RSC in SPP, examples of existing subregional groups that could also evolve into SPEs are the

⁶ This would include complying with state policies on energy efficiency, distributed resources, and other alternative sources of power, as well as state renewable portfolio standards and other state policies.

subregional planning groups within the WECC⁷ and the Upper Midwest Transmission Development Initiative (“UMTDI”, which was created with the cooperation of the governors of Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin). Some of these existing groups have already started to address cost allocation issues for a broad range of regional transmission facilities, including for renewables integration. Examples are OMS (through its CARP effort), UMDTI, SPP’s RCS, and the Cost Allocation Committee within the Northern Tier Transmission Group. These groups and efforts also work closely with RTOs and TOs which support regional planning efforts and help inform cost allocation decision making.

With respect to process requirements, we suggest that many of the planning process requirements the Commission places on individual TOs or RTOs under Order 890—coordination, openness, transparency, information exchange, comparability, dispute resolution, and regional coordination—be transferred to the SPEs under our proposal.⁸ The Commission has already developed an extensive record on these process criteria and the industry has accumulated significant experience applying them. The final two of the Commission’s nine process criteria from Order 890, economic studies and cost allocation, are obviously changed by our proposal here.

When creating these plans along with existing TOs and RTOs, state public service commissions and other state energy planning and siting agencies, and the comparable representatives of non-jurisdictional load-serving entities, all play an important role. We note

⁷ Subregional planning groups in the WECC are the Colorado Coordinated Planning Group, ColumbiaGrid, Northern Tier Transmission Group, Northwest Transmission Assessment Committee, Pacific Southwest Planning Association, Southwest Area Transmission, and WestConnect.

⁸ This does not imply that jurisdictional TOs cease planning efforts for their own use as critical contributions to the SPE plan. Existing TOs will be vital participants in these planning efforts and they should be fully involved in every stage of the process.

that entities of this nature have the longest history of making and approving expansion plans, may have obligations to participate in the SPE plan, and are certainly very important stakeholders.

Three key ingredients to plans of this nature are (a) the number and type of grid expansion scenarios to consider; (b) the economic and technical assumptions employed in evaluating alternative expansion plans; and (c) the range of transmission-related benefits considered when assessing whether overall regional or subregional benefits exceed total costs. With regard to (a), the SPE should solicit and consider grid expansion proposals from all stakeholders, operating within existing requirements in transmission tariffs and other applicable rules.⁹ The SPE should use reasonable efforts to consider all proposed expansions and study them within a reasonable number of expansion scenarios, with the understanding that no planning process is perfect and that a series of screening and scenario creation steps will be necessary to create a reasonable number of alternatives that can be fully evaluated. These realities are familiar to all planners operating in the industry today.

With respect to economic and technical assumptions, the SPE should again solicit input on the proper data to use in its planning exercise and render a reasonable judgment. If the SPE is administering an open, transparent process, its assumptions will be visible to all and easily commented on. Finally, the range of transmission-related benefits considered in the planning process should be flexible and include both readily-quantifiable benefits (such as dispatch-related production cost savings) as well as potentially important but difficult-to-quantify

⁹ For example, if an RTO tariff or process now provides for a right of first refusal by a TO within its footprint that right should be honored and included in the planning process. However, if these existing tariffs and other applicable rules are inadequate, SPEs, RTOs, and other entities would always be able to coordinate to implement changes to the existing framework.

operational, competitive, investment cost, environmental, insurance, economic development, and other relevant benefits.

We propose that the objective function of the plan be a combination of a reasonable expectation of highest net benefits and/or lowest cost. We are certainly mindful of the fact that the process of estimating the regional cost or benefit of transmission investments involves substantial uncertainties at every stage. A requirement that the SPE produce a plan that has the lowest *possible* demonstrated cost would be an invitation to dispute planning assumptions and argue about something that cannot be definitely proven. Instead, the obligation of the SPE should be simply to demonstrate that its plan, which meets its many policy and process objectives, is reasonably expected to result in higher net benefits or in lower costs for the planning region than alternatives, factoring in the range of uncertainties and risks. Plans that may not be expected to offer lower costs in achieving stated policy objectives would still be desirable if they are expected to offer higher overall net benefits.

One of the most important elements included in the SPE plans we envision is that states commit to a proposed allocation of costs for all transmission facilities expected to enter service during the planning cycle, *i.e.* approximately the next three to five years. This would mean that representatives of the states in the SPE would need to be in agreement with and be able to commit to the proposed allocation and recovery of expansion costs. If such a commitment is not achieved, the SPE could employ the Commission to mediate a cost allocation agreement.

We do not recommend that the Commission mandate a particular binding framework for the allocation and recovery of these costs but rather accept an SPE's proposed allocations if the SPE and representatives of the affected TOs and states have used their best efforts to arrive at the

proposed allocation. Moreover, if specific planned expansions are already subject to a pre-existing cost allocation protocol we do not propose changing it. While the Commission serves as the ultimate arbiter of cost allocation, it is our hope that a Commission decision need never have to replace a voluntarily-reached SPE agreement.

Finally, the Commission will have to allow significant latitude to the SPE to amend and update its plan. Everyone familiar with electric industry resource planning understands that circumstances evolve over time and very few electric facilities enter service without changes to their scope, schedule and/or cost. We suggest that an appropriate planning cycle would be three to five years, with amendments allowed whenever needed.

IV. ADDITIONAL OBSERVATIONS ON COST ALLOCATION

To facilitate regional planning and cost allocation commitments by SPEs, the Commission may specify a framework that would be applied if SPEs were unable to resolve cost allocation. We recommend that such a framework be relatively simple. To the extent the Commission was inclined to include some form of “beneficiary pays” principles, these should not be formulaic nor be based on narrow definitions of readily-quantified benefits. The experience to date shows that such formulaic approaches can become unworkable because definitions of readily-quantifiable benefits can be so narrow that the quantified overall benefits can no longer support the proposed transmission project for which cost allocation is sought.

While proper cost allocations should always be based on a reasonable link between allocated costs and total benefits received, one needs to recognize that the benefits of many transmission projects are broad in scope (*i.e.*, ranging from dispatch cost savings, to regional

reliability benefits, to economic development benefits of renewable power investments), widespread geographically (*i.e.*, multiple TOs and states), diverse in their effects on market participants (*i.e.*, individual market participants may capture one set of benefits but not others), and occur over a long period of time (*i.e.*, several decades). Attempts to quantify how some of these benefits are captured within any one specific area or state often can be sufficiently uncertain so as to be of little practical value for allocating costs.

Because of the broad, diverse, and long-lasting nature of transmission-related benefits, some forms of regional or subregional postage stamp tariffs may offer workable “second-best” solutions to resolve the regional cost allocation challenge. Examples of such solutions include the postage stamp tariff structures used in both ERCOT and by CAISO, the postage stamp allocation for reliability and economic projects in PJM and ISO New England, the highway/byway approach under development in SPP, and the injection-withdrawal tariff currently being explored by OMS.

Commenter's Certification

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.



Peter Fox-Penner
The Brattle Group
1850 M Street, NW, Suite 1200
Washington, DC 20036
202.955.5050



Johannes Pfeifenberger
The Brattle Group
44 Brattle Street
Cambridge, MA 02136
617.864.7900



Delphine Hou
The Brattle Group
1850 M Street, NW, Suite 1200
Washington, DC 20036
202.955.5050

ATTACHMENT A:
Transmission Investment Needs and Cost Allocation:
New Challenges and Models

The Brattle Group

Transmission Investment Needs and Cost Allocation: New Challenges and Models

Presented to:
Federal Energy Regulatory Commission Staff

Presented by:
Johannes Pfeifenberger, Peter Fox-Penner, Delphine Hou
The Brattle Group

December 1, 2009

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Antitrust/Competition Commercial Damages Environmental Litigation and Regulation Forensic Economics Intellectual Property International Arbitration
International Trade Product Liability Regulatory Finance and Accounting Risk Management Securities Tax Utility Regulatory Policy and Ratemaking
Valuation Electric Power Financial Institutions Natural Gas Petroleum Pharmaceuticals, Medical Devices, and Biotechnology Telecommunications and
Media Transportation

Presentation Overview

I. Investment Trends and Transmission Needs

II. Cost Allocation and Cost Recovery

- ◆ The New Barrier to Investments
- ◆ Existing and Promising New Approaches

III. Case Studies

Appendix: “Difficult-to-Quantify” Transmission Benefits

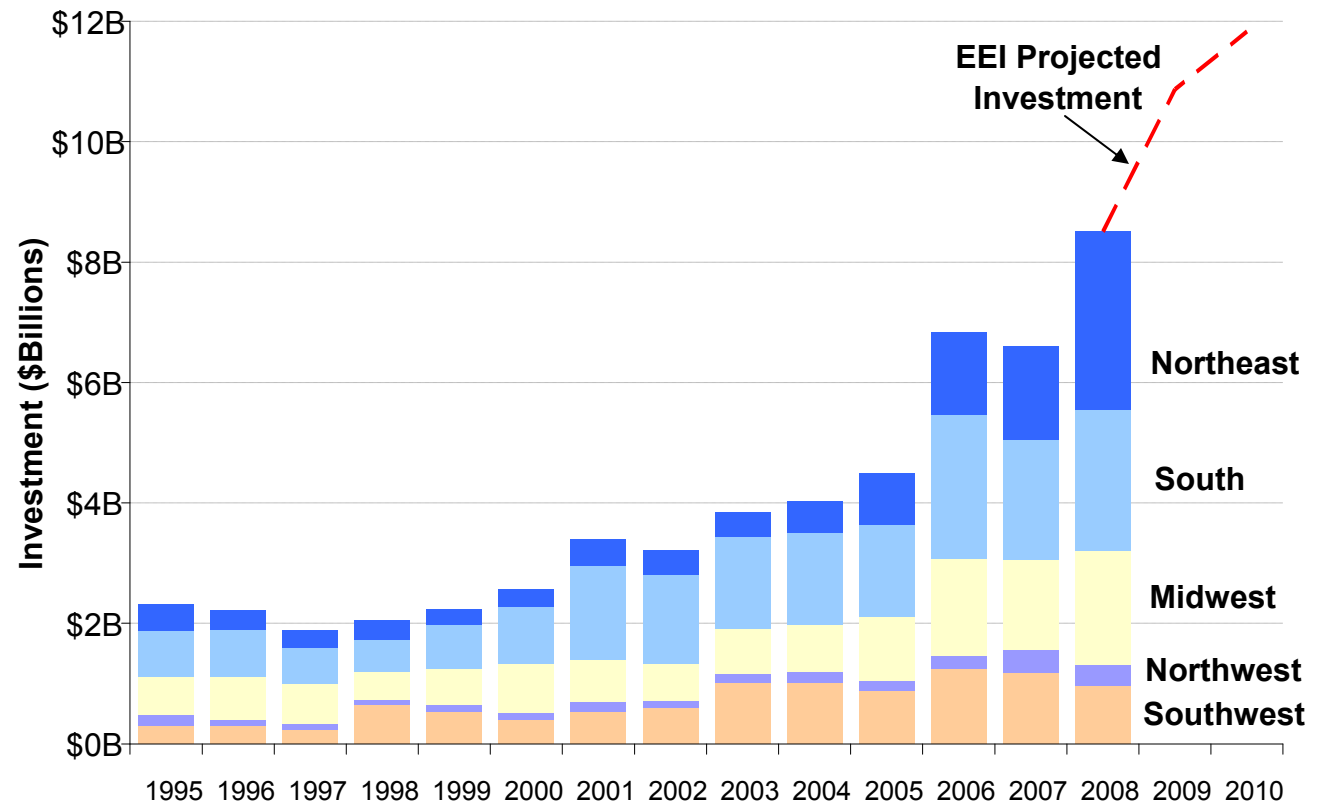
Transmission Investments are on a Strong Upward Trend

Transmission investment in 2008 is quadruple average 1990s level

Likely investment of \$10+ billion annually going forward

NERC projects transmission additions to triple from about 1,000 miles/yr in 2000-08 to 3,100 miles/yr in 2009-18

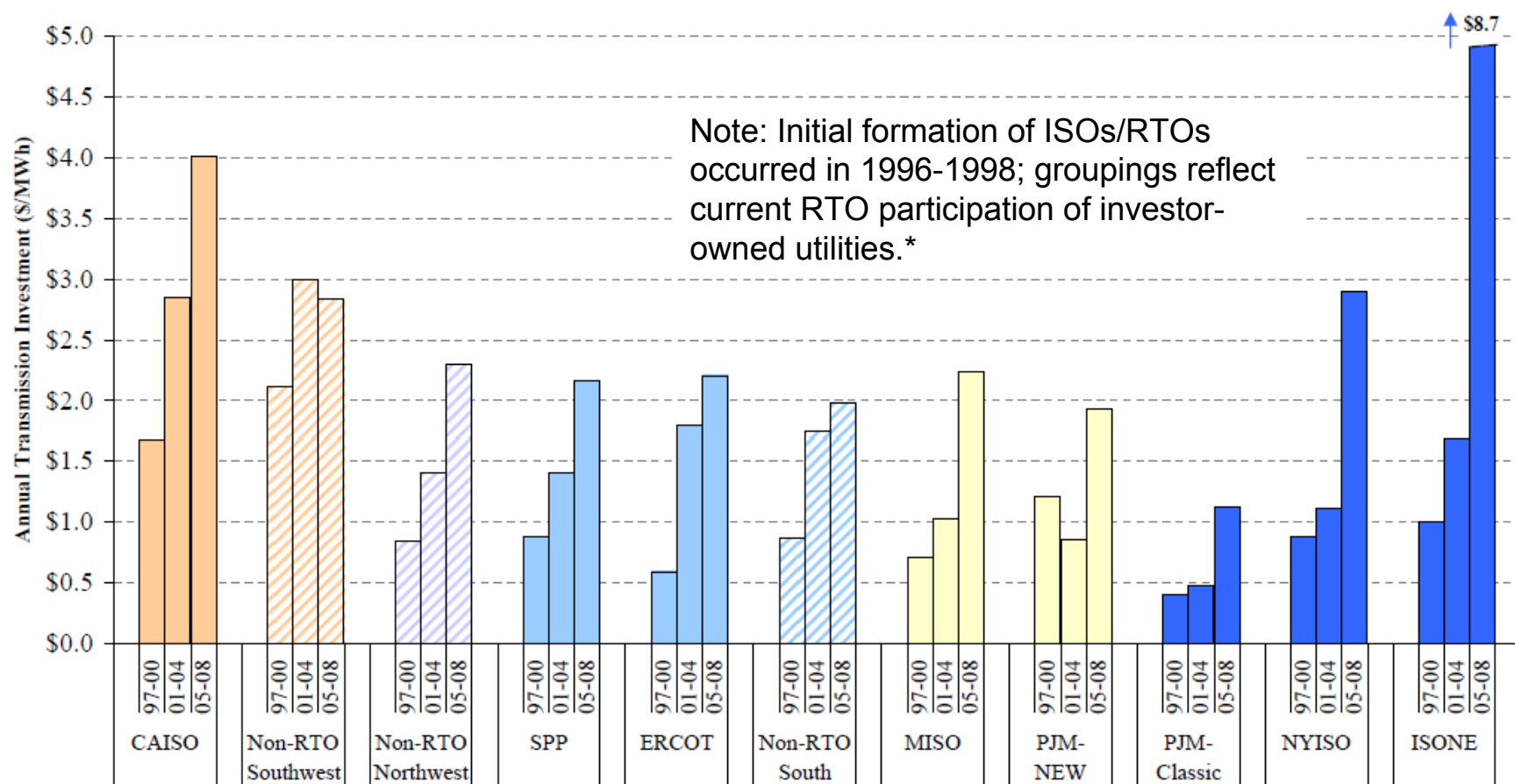
**Actual Transmission Net Plant Additions
By Investor-Owned Utilities**



Source: The Brattle Group based on EEI survey and FERC Form 1 data compiled by Global Energy Decisions, Inc., The Velocity Suite. Investment in miles per year from NERC ES&D database and NERC 2008 Long-Term Assessment.

Transmission Investment Trends Vary by Region

Transmission Plant Additions Per MWh of Regional Load by Investor-Owned Utilities



Source: The Brattle Group based on FERC Form 1 and EIA Form 861 data compiled by Global Energy Decisions, Inc., The Velocity Suite.

*Transmission investment of investor-owned utilities; expressed as total investment dollars per MWh of retail sales.

PJM-New includes Commonwealth Edison, AEP, Dayton, Duquesne, and Dominion. PJM-Classic includes all other PJM members.

Drivers of Future Transmission Additions

- ◆ Near term load growth will be modest to flat if proposed efficiency and demand-side initiatives are implemented – minor driver in most cases
- ◆ Renewable mandates will add up to 130 GW by 2020 and be the major driver of transmission additions
- ◆ Reliability, cyber security, and old facility replacement are lesser but significant drivers
- ◆ Federal climate legislation will boost renewables but reduce demand and probably increase nuclear/CCS coal
- ◆ Better technology to increase voltage, reconductor, or add smart controls – but may ultimately lower the number of new circuit-miles
- ◆ Distributed generation – slow but steady increase
- ◆ Overall, drivers are positive

\$120 billion of New Conceptual and Planned Projects

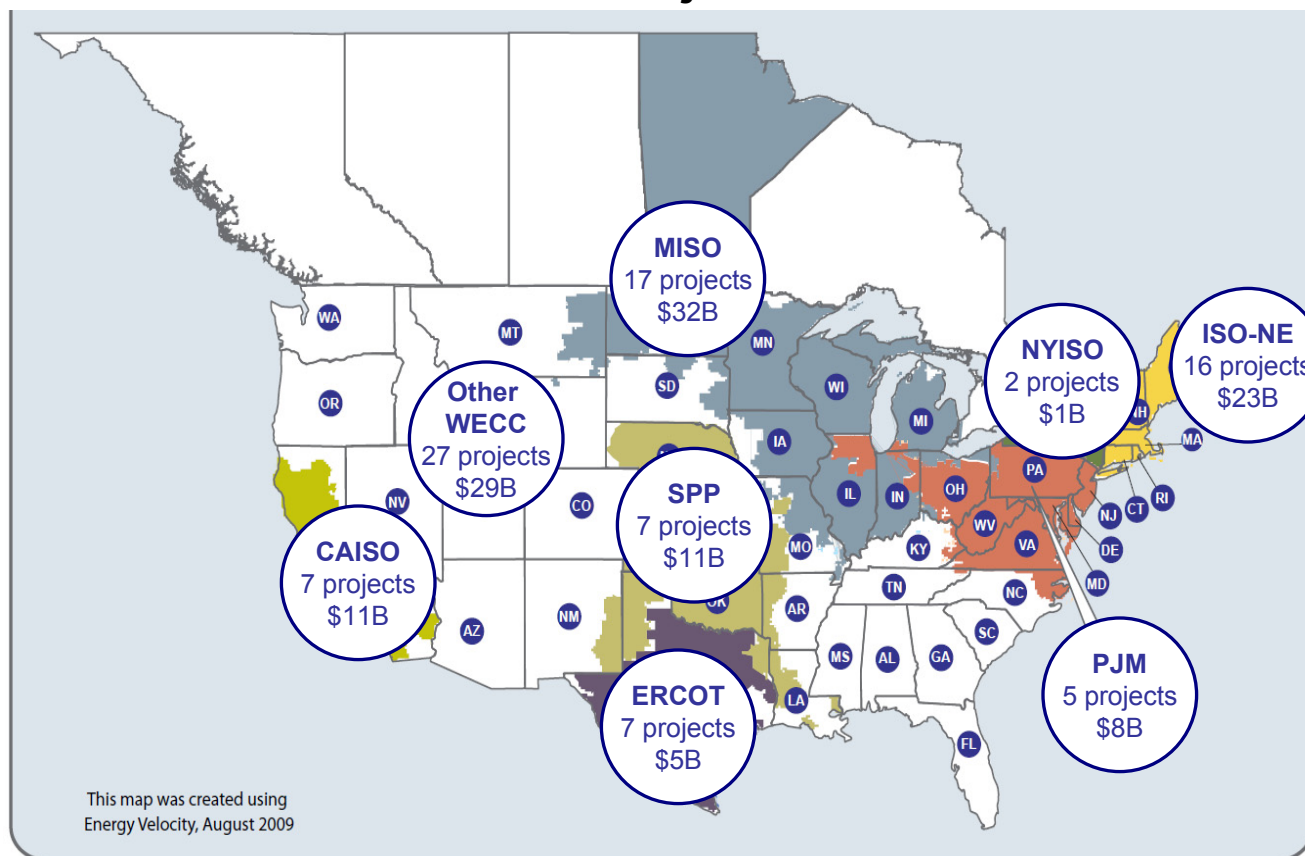
We identified approx. 90 (often overlapping) conceptual and planned projects larger than \$100 million for a total of at least \$120 billion.

Most projects will be built by incumbents.

Some opportunities for participation of transmission companies outside their traditional service areas.

Many of the projects unlikely to get built as proposed.

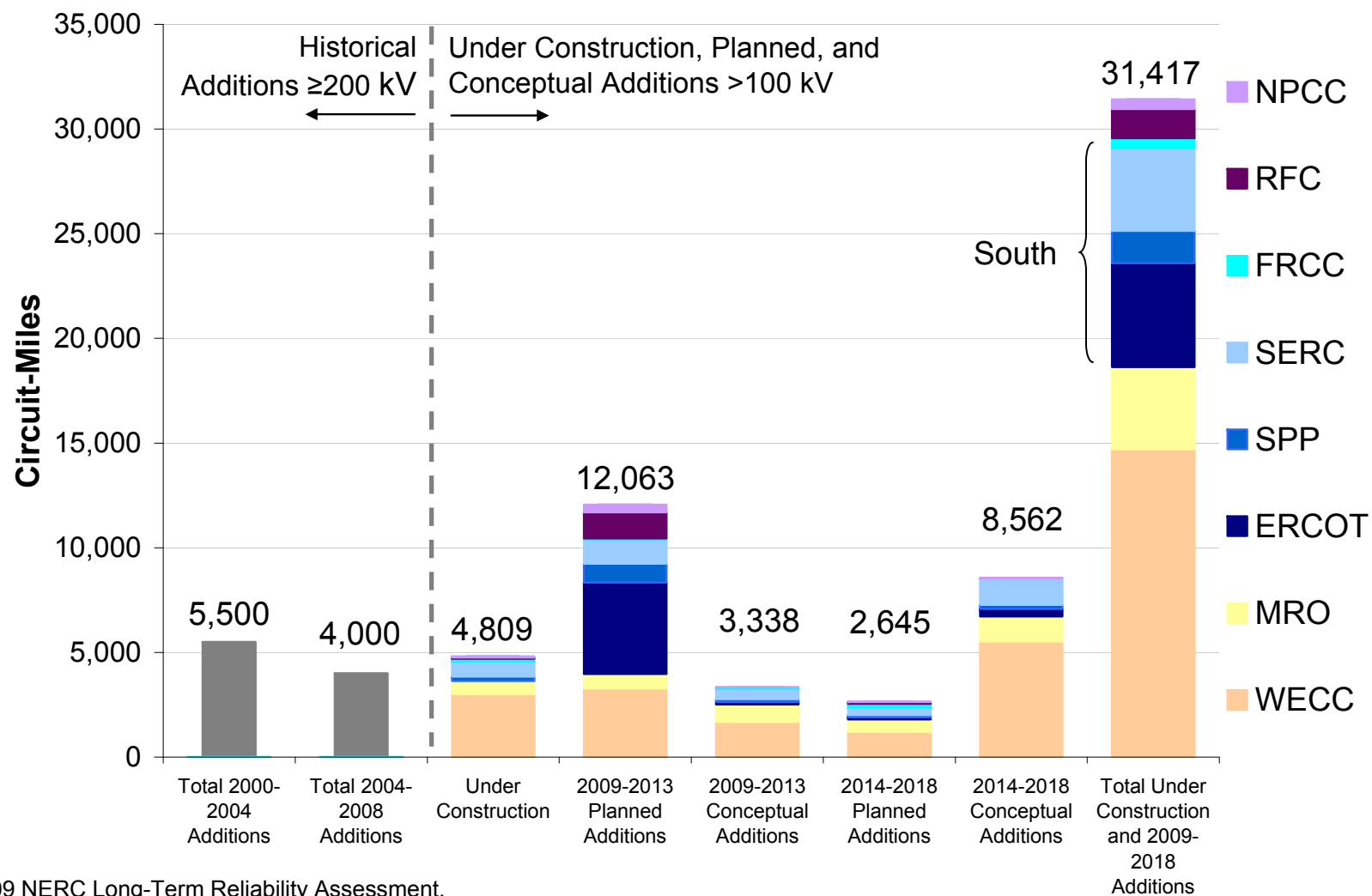
\$120 Billion in Conceptual and Planned Transmission Projects as of 9/09



Source: Map from FERC. Project data collected by *The Brattle Group* from multiple sources and aggregated to the regional level.

NERC: 31,000 Circuit-Miles of New Transmission by 2018

Historical and Additional Transmission Circuit-Miles by NERC Reliability Region



Source: 2009 NERC Long-Term Reliability Assessment.

How Much Transmission is Actually Needed?

The table compares various renewable overlay studies with the 2009 NERC Long-Term Reliability Assessment estimates for miles of transmission >100kV under construction, planned, and proposed from 2009-2018

Study	Description	Miles of Transmission According to Study	Miles of Transmission Projected by NERC	Transmission Cost (\$/kW wind) ³
DOE 20% by 2030	National buildout after 10% of existing transmission used to integrate 293 GW wind by 2030	12,650	31,418	\$207 [\$61bn total cost]
AEP 765kV Overlay	National 765kV Overlay to integrate 200-400 GW of wind	19,000	31,418	\$150 - \$200 [\$60bn total cost]
ISO New England	Integrate 2-15 GW of wind from New England and parts of Canada	1,015 to 5,000	438	\$1,109 - \$3,575 [\$5-\$29bn total cost]
JCSP	≥345kV overlay in parts of Eastern Interconnect to integrate 60 GW / 229 GW of wind by 2024	9,979 / 14,480	10,799	\$837 / \$349 [\$49/\$80bn total cost]
RGOS ¹	Integrate 25 GW wind in Upper Midwest	4,929 to 7,451	3,924	\$833 - \$1,000 [\$17-\$23bn total cost]
SPP EHV Overlay	765/500kV overlay to integrate ~21 GW wind in SPP by 2027	3,400 ²	1,531	\$329 [\$7bn total cost]
ERCOT CREZ	345kV overlay to integrate ~12 GW wind in ERCOT by 2013	2,376	4,970	\$427 [\$5bn total cost]

¹As of September 17, 2009. ²Estimated. ³Addition of non-wind capacity in \$/kW cost calculation will decrease the estimates for some studies.

Takeaways

Transmission construction and plans for construction are at 4x 1990s pace; expected to continue for a decade or more.

While efficiency policies are likely to constrain load growth, possibly to the point of flat sales, transmission builds will still be needed

- ◆ To integrate renewables due to state RPS and climate goals
- ◆ For reliability, cyber-security, and old facility replacement

Federal climate legislation with a RES will boost renewable and transmission needs, particularly in the Midwest and Southeast.

An unprecedented amount of new transmission is on the drawing boards, mainly point-to-point and incremental builds.

The issues are total need and execution.

I. Investment Trends and Transmission Needs

II. Cost Allocation and Cost Recovery

- ◆ The New Barrier to Investments
- ◆ Existing and Promising New Approaches

III. Case Studies

Appendix: “Difficult-to-Quantify” Transmission Benefits

The 4 “Ps” of Transmission Investments

Planning (utility, state, RTO, inter-RTO or region)

Permitting (state siting boards, state commissions, federal agencies)

- Environmental permits
- Determination of “need” (reliability, economics, ...)

Paying (tariff- and non-tariff-based cost allocation and recovery)

Proprietorship (ownership models)

- Right of first refusal by incumbent transmission owners
- Joint ownership models
- Third-party ownership
- Competitive bidding processes

**This section of the presentation focuses on “paying” issues:
Cost allocation and cost recovery**

Cost Allocation: What Works and What Doesn't

Existing cost allocation processes have varying degrees of effectiveness.

- ◆ Works well: cost recovery for traditional single-utility, single-state projects built to satisfy reliability needs
- ◆ Mostly works: cost allocation and recovery at the RTO level for reliability-driven regional projects and *conventional* generator interconnection requests
 - Some unintended consequences of existing RTO cost allocation framework
 - MISO's assignment of wind integration costs illustrates difficulties
- ◆ Still mostly unresolved: Cost allocation and recovery for all other types of regional projects, including “economic” projects, *renewable integration* projects, EHV overlay projects, and any multi-purpose projects
 - Only two single-state ISOs (ERCOT and CAISO) have been able to resolve cost allocation for multi-utility, multi-purpose, and renewable integration projects
 - SPP closer to resolving this issue
 - MISO and other RTOs and regions have only started to address this issue
 - Court remand of PJM postage stamp tariff creates additional uncertainty

How Cost Allocation Creates a Barrier for Regional Projects

Planning, permitting, and cost allocation process is “easier” (and more sequential) for single-state projects:

- ◆ Planning determines need (e.g., overall benefits in excess of total project costs)
- ◆ State permitting/regulatory process confirms need and approves project
- ◆ Approved projects receive cost recovery from customers within state
- ◆ Still, some challenges for in-state projects with regional benefits (e.g., Brookings line in MN)

Interaction between cost allocation and permitting creates barrier for many multi-TO, multi-state projects:

- ◆ Permitting processes primarily focused on costs and benefits to each individual state: share of benefit in excess of allocated share of costs
- ◆ “Beneficiary pays” framework creates incentives to dismiss benefits to achieve lower cost allocation
- ◆ Result: projects that are beneficial to region often do not appear to be beneficial to individual states based on their shares of costs and benefits

How Cost Allocation Creates a Barrier for Regional Projects

Eastern RTOs' economic study frameworks contribute to the problem:

- ◆ Narrow focus on “production cost” simulation models that quantify short-term dispatch cost savings but cannot capture a wide range of transmission-related benefits:

“The real societal benefit from adding transmission capacity comes in the form of enhanced reliability, reduced market power, decreases in system capital and variable operating costs and changes in total demand. The benefits associated with reliability, capital costs, market power and demand are not included in this [type of] analysis.”

(SSGWI Transmission Report for WECC, Oct 2003; emphasis added)

- ◆ Narrow or unrealistic modeling assumptions and simplistic benefit metrics fail to capture full impact of transmission buildout
- ◆ Process fails to capture important (but hard to quantify) benefits of regional transmission projects

Not a single sizable “economic” project approved in MISO, PJM, NYISO, ISO-NE

Important Transmission Benefits are Often Ignored

Eastern RTO planning processes based on “production cost” studies generally do not assess important benefits:

- | | | |
|---|---|---------------------------------------|
| ◆ Enhanced market competitiveness | } | Additional market benefits |
| ◆ Enhanced market liquidity | | |
| ◆ Economic value of reliability benefits | } | Reliability/operational benefits |
| ◆ Added operational and A/S benefits | | |
| ◆ Insurance and risk mitigation benefits | | |
| ◆ Capacity benefits | } | Investment and resource cost benefits |
| ◆ Long-term resource cost advantage | | |
| ◆ Synergies with other transmission projects | | |
| ◆ Impacts on fuel markets | } | External benefits |
| ◆ Environmental and renewable access benefits | | |
| ◆ Economic benefits from construction and taxes | | |

These omitted transmission-related economic benefits, often doubling benefits from production cost studies (see Appendix), make formulaic beneficiary-pays cost allocation approaches unworkable

Cost Allocation and Recovery Approaches

Five widely-used methodologies to allocate and recover costs from transmission customers

- 1) License plate (LP): each utility recovers the costs of its own transmission investments (usually located within its footprint).
- 2) Beneficiary pays: various formulas that allocate costs of transmission investments to individual TOs that benefit from a project, even if the project is not owned by the beneficiaries. TOs then recover allocated costs in their LP tariffs from own customers.
- 3) Postage stamp (PS): transmission costs are recovered uniformly from all loads in a defined market area (e.g., RTO-wide in ERCOT and CAISO).
 - In some cases (e.g., SPP, MISO, PJM) cost of certain project types are allocated uniformly to TOs, who then recover these allocated costs in their LP tariffs.
- 4) Direct assignment: transmission costs associated with generation interconnection or other transmission service requests are fully or partially assigned to requesting entity.
- 5) Merchant cost recovery (M): the project sponsors recover the cost of the investment outside regulated tariffs (e.g., via negotiated rates with specific customers); largely applies to DC lines where transmission use can be controlled.

So far, only TX and CA's broad application of postage stamp rates have mostly resolved cost allocation barrier to economic and multi-purpose project development

Current Cost Allocation is Complex and Incomplete

LP = License Plate Tariffs; PS = Postage Stamp Tariffs or Postage Stamp Allocation; M = Merchant Lines; GI = Generation Interconnection Tariffs;
✓ = workable approach; n/a = workable approach not yet available

RTO/ Region	General Tariff Methodology	Reliability	“Economic” Projects	Renewables	Regional/Overlay Projects
CAISO	PS 100% ≥200kV; otherwise LP or M	✓	✓	✓ GI and specific location-constrained resource tariff (Tehachapi)	✓ Not specifically discussed, but 100% PS of all network facilities
ERCOT	PS or M	✓	✓	✓ CREZ (100% PS)	✓ Not specifically discussed, but 100% PS of all network facilities
SPP	PS 33% ≥60kV reliability projects; PS allocation for balanced portfolio; otherwise LP or M	✓	✓ “Balanced Portfolio” allocation	GI; developing EHV overlay and PS (H/B CARD) treatment	Developing EHV overlay and postage stamp treatment (H/B CARD to be approved)
ISO-NE	PS 100% ≥115kV; otherwise LP or M	✓	too narrowly defined	n/a (GI only)	n/a
PJM	PS sharing 100% ≥500kV; otherwise LP allocation (beneficiary pays) or M	✓	too narrowly defined	n/a (GI only)	n/a
MISO	PS sharing 20% ≥345kV; rest LP allocation (beneficiary pays) or M	✓	too narrowly defined	n/a (GI only)	n/a – under study via CARP
PJM-MISO	Sharing of reliability project based on net flows/beneficiaries	✓	too narrowly defined	n/a	n/a
NYISO	LP allocation (based on beneficiary pays) or M	✓	too narrowly defined	n/a (GI only)	n/a
WECC (non-CA)	LP; often with cost allocation based on co-ownership	✓	✓ (differs across WEC subregions)	✓ GI (e.g., BPA open season); under discussion in WREZ	n/a – under discussion in WREZ

Promising New Tariff-Based Cost Recovery Approaches

Some attractive approaches (and some hopeful efforts) for allocating costs of renewable power projects within RTO tariffs:

- ◆ CAISO:
 - Postage stamp for all network upgrades $\geq 200\text{kV}$
 - *Tehachapi LCRI* approach: up-front postage stamp funding of project, later charged back to interconnecting generators, thereby solving chicken-egg problem (see [project summary](#))
- ◆ ERCOT:
 - Postage stamp for all *CREZ* transmission being built to integrate 18,000 MW of new wind; build-out awarded to a diverse set of 7 transmission companies (see [project summary](#))
- ◆ WECC:
 - WECC utilities often use co-ownership of lines (within and out of footprint) based on contractual allocations of point-to-point capability to resolve cost allocation issue
 - BPA open season approach for $>5,500$ MW renewable generator interconnections
 - Northern Tier's multi-state cost allocation committee
- ◆ SPP:
 - Developing EHV overlay and postage stamp recovery
- ◆ MISO's CARP:
 - 13-state (OMS) effort to design "injection-withdrawal tariff" -- regional postage stamp, subregional postage stamp, and local license plate rates charged to both load and generators
 - Decision late this year or early 2010

Non-Tariff-Based Cost Recovery Options

A number of transmission developments have successfully bypassed the RTO's tariff-based RTO cost recovery options:

- ◆ Long-term merchant PPAs:
 - HVDC cable from PJM to LIPA financed with long-term PPA for capacity
 - Example: Neptune (independent transmission LLC)
- ◆ Merchant anchor tenant with open season:
 - Anchor tenant signs up for large portion of capacity, open season for rest
 - Standard model used for new pipelines
 - Example: Zephyr and Chinook HVDC lines (TransCanada; see project summary)
- ◆ Regulated PPA with ISO operational control:
 - Utilities own transmission, sold bilaterally to generator at state regulated rates, buy bundled long-term PPA
 - Project under RTO operational control but bypasses RTO cost recovery
 - Example: NU-NSTAR-HQ HVDC link (see project summary)
- ◆ Mostly used for HVDC lines because (by being “controllable” like pipelines) they allow owners/customers to capture more of the system benefits than AC projects.

Takeaways: Cost Allocation – The Status Quo

- ◆ Resolved only for reliability projects, conventional generation interconnections, in-state economic projects
- ◆ Despite years of effort, cost allocation remains number one barrier for multi-state, multi-utility transmission projects
 - Complicated, unworkable for most new projects
 - Slows transmission development needed for large-scale renewable integration (in particular out-of-footprint and regional overlay projects)
- ◆ TX and CA have mostly resolved issue (but much easier in single states)
- ◆ Promising efforts underway elsewhere but uncertain success
 - Outcome and timing remains uncertain (e.g., MISO CARP)
 - SPP more promising
- ◆ Some options are available to bypass of RTO cost recovery through merchant or regulated bilateral contracts

Takeaways: Options and Recommendations

- ◆ Simplify!
 - Formulaic “beneficiary pays” concepts (we’re economists) unworkable due to broad range and wide-spread nature of transmission-related benefits
 - Some forms of regional and sub-regional postage stamp tariffs (including injection-withdrawal approaches) offer hope for workable “second-best” solutions
 - CA and TX (!) arrived at similar postage stamp solutions
- ◆ Strong support from (or direct involvement by) state governors needed to achieve regional solutions
 - RTOs, transmission owners, and market unlikely to move beyond least-common denominator approaches
 - State commissions lack “political authority” to consider broader policy objectives and negotiate regional solutions
 - Even state-level solutions by CAISO and ERCOT achieved only through legislative mandates
- ◆ Threat of federal cost-allocation backstop seems necessary to achieving timely multi-state allocation agreements

Takeaways: Finding A Siting and Cost Allocation Compromise

- ◆ States are resisting a stronger federal role in mandating transmission lines or siting approval.
- ◆ Conversely, without the threat of federal action it is difficult for states to make multi-state allocation deals.
- ◆ Suggested compromise:
 - ◆ Federal government sets common regional planning process rules and region-specific policy goals
 - ◆ States must form regional planning groups (smaller than interconnection)
 - ◆ Regional plans must meet all reliability rules, renewable targets, carbon targets, and any other legislated goals at the lowest expected costs and states must site all proposed lines in plan
 - ◆ Regional plans should have proposed cost allocations for all EHV lines
 - ◆ If regions fail to provide a plan meeting the requirements, DOE or FERC can develop a plan
 - ◆ Backstop authority attaches to any lines in a federal plan
- ◆ In other words,
 - ◆ Require regional planning that meets standards and has deadlines
 - ◆ Require states to site lines in the plan and the FERC to approve cost allocation
 - ◆ Federal backstop authority expands *only* if the regions do not provide and approve a plan - - and applies to the plan, not the line

I. Investment Trends and Transmission Needs

II. Cost Allocation and Cost Recovery

- ◆ The New Barrier to Investments
- ◆ Existing and Promising New Approaches

III. Case Studies

Appendix: “Difficult-to-Quantify” Transmission Benefits

Transmission Projects: Case Studies

Significant projects are being planned across the US.

- ◆ 90 projects of over \$100 million (total \$120 billion) on the drawing boards
- ◆ Many projects are conceptual and duplicative and may be reconfigured, including owner or developer changes

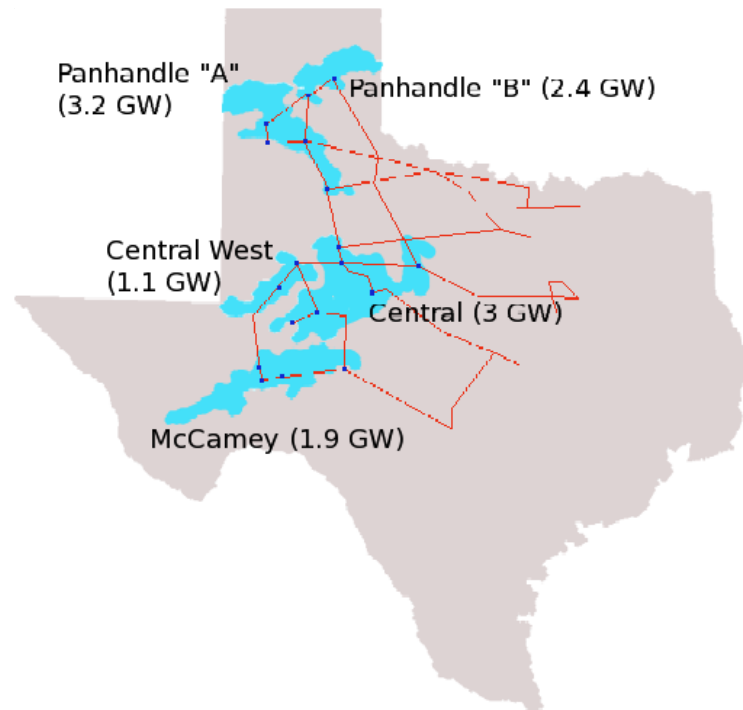
Projects mostly developed and owned by incumbents, but some opportunities for third-party investments

- ◆ HVDC lines
- ◆ Texas CREZ projects openly bid
- ◆ Other regions considering opening to non-incumbents (SPP, Alberta)

Projects and regional efforts with promising cost allocation models:

- ◆ Cost recovery in ERCOT, CAISO, and potentially SPP
- ◆ “Anchor tenant” HVDC lines and similar merchant models
- ◆ CAISO Tehachapi approach – build now, recover from generators later

ERCOT Competitive Renewable Energy Zones (CREZ)



Overview of Projects

- ◆ \$4.93B in total transmission investment, 345 kV lines
- ◆ Need: 7,100 MW of wind in ERCOT today; CREZ integrates up to 18,000MW of total wind resources to be connected to the grid
- ◆ Status: development underway; completion expected 2013-2014

Source: ERCOT and NREL

Relevance: only example of comprehensive renewable overlay open to outside bidders and close to start of construction

Establishment of CREZ spanned multiple agencies:

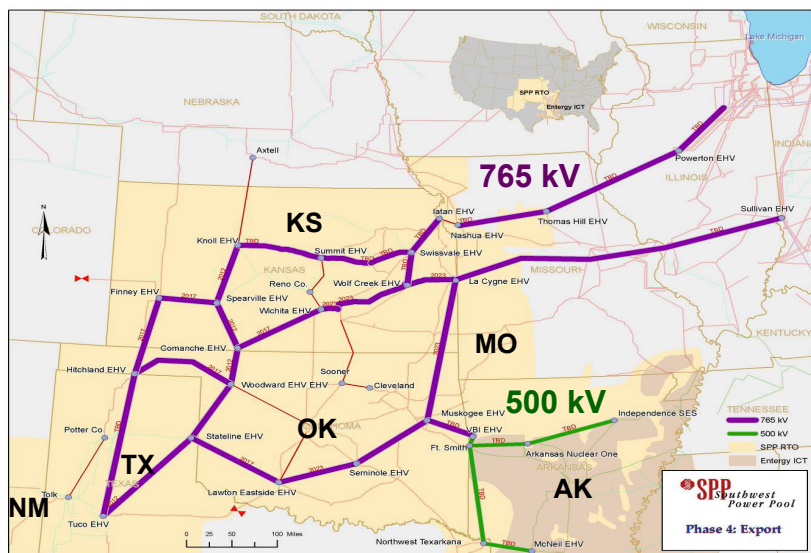
- ◆ Legislation raised RPS, mandated CREZ process to help meet the RPS, and required postage stamp cost allocation
- ◆ ERCOT identified high-potential areas for wind and potential transmission solutions
- ◆ Public Utilities Commission of Texas selected transmission options and established competitive bidding process for transmission to serve these areas

Positive results for new entrants:

- ◆ 14 companies awarded projects, including non-incumbents LS Power subsidiary, AEP-MidAmerican JV, Lower Colorado River Authority, NextEra subsidiary, Wind Energy Transmission Texas
- ◆ Postage-stamp allocation for all CREZ projects

Recent legislation passed restricting new entrants

SPP Conceptual EHV Overlay



Source: 2008 SPP Transmission Expansion Plan, p. 70

Initial EHV overlay plan:

- ◆ Ongoing system modeling and costs-benefit analysis of 2,250 miles of 500 and 765 kV overlay at cost of approx. \$8 billion
- ◆ Overlay project for 20 GW of wind in four phases through 2027

Plans scaled back to \$1.3 billion of priority projects by 2014 and integrate 7-14 GW of wind over 10 years.

Relevance: Hopeful example of multi-state planning and cost allocation

New cost allocation proposal to be developed for filing with FERC:

- ◆ Regional State Committee and SPP Board of Directors tentatively approved a “Highway / Byway” cost allocation rate design (H/B CARD):
 - “Highway projects” or transmission ≥ 300 kV, costs are shared on postage-stamp basis
 - “Byway projects” between 100 to < 300 kV have 1/3 of costs shared on postage stamp basis; 2/3 allocated to local zones
 - “Byway projects” < 100 kV costs fully allocated to local zones
- ◆ Would apply to \$1.3 billion in priority projects, some of which already face significant SPP-internal opposition over scale and cost allocation

CAISO “Tehachapi” LCRI solution



Southern California Edison Project:

- ◆ \$1.8 billion in total costs, 300 miles, 230-500kV in 3 segments
- ◆ Purpose: connect existing and potential wind resources to load centers in Southern California
- ◆ Status: multi-stage project; 1st segments online before end of 2009, final stages online in 2013

Relevance: new tariff-based cost recovery model

- ◆ Project need: over 4,000 MW of potential wind (and some solar) require new transmission
 - Segments 1 and 2 are *network* facilities to which existing postage stamp recovery applies
 - Segment 3 is location-constrained generation interconnection line for which new solution was needed
- ◆ Solution: creation of the FERC-approved Location Constrained Resources Interconnection tariff (LCRI) for Segment 3
- ◆ LCRI recovery for Segment 3: transmission owners pay upfront costs (postage stamp), but as generation comes online, generators pay pro-rata share of costs.
- ◆ Key LCRI conditions: high-voltage transmission facility, must support at least two location constrained resources, cap on total costs eligible, generators must have “demonstrated their interest” in at least 60% of the line

Project is an example of a tariff-based solution to renewable interconnection in advance of (all) generation build.

Other Promising Tariff-Based Approaches in WECC

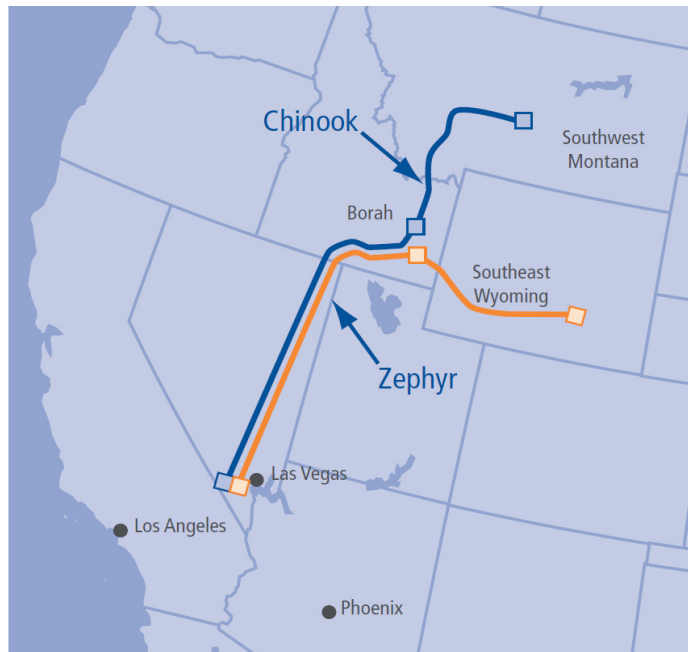
Cost Allocation Committee (CAC) Process of Northern Tier Transmission Group (NTTG)

- NTTG is group of transmission providers and customers in Northwest and Mountain states; coordinates transmission systems operations, services, and planning.
- CAC consists of representatives from commissions, consumer advocates and public power in ID, MT, OR, UT and WY.
- Developed cost allocation principles.
- Reviews proposed regional projects and makes non-binding cost allocation recommendations based on detailed data, analyses, C-B studies, and cost allocation/ recovery proposals provided by project developers, sponsors and interested stakeholders.
- Evaluated and made recommendations for 16 projects (many “multi-use”) with cost of approx. \$10 billion.
- Mostly license plate cost recovery based on allocation of project ownership and service/reliability obligations.

BPA Network Open Season

- BPA is allowing generation interconnection customers to sign a binding agreement to take transmission service, if available, at embedded cost rates before each network open season deadline.
- BPA guarantees to provide the transmission service as long as it can do so with existing capacity or at costs no greater than its embedded rate.
- Compared to first-come, first-serve approach to clearing interconnection queue, this is hoped to better align new resource development with new transmission development, especially for wind resources.
- The first network open season began April 2008 and will be held at least annually. As of September 2009, approx. 5,500 MW of generation interconnection request (mostly wind) from 2008 network open season process.
- As a result, BPA will invest in 5 transmission projects providing 3,700 MW of new service.

Proposed Chinook and Zephyr Lines



Project proposed by TransCanada:

- ◆ Two 500kV DC lines, 3,000 MW each, \$3 billion each
- ◆ Purpose - to bring wind from Montana and Wyoming into the Southwest, help meet state RPS requirements
- ◆ Construction to begin 2012

Source: http://www.transcanada.com/company/zephyr_chinook.html.

Relevance: merchant cost recovery model based on anchor tenant and open season

- ◆ FERC granted the projects negotiated rate authority
- ◆ Project marks the first time FERC allowed an anchor tenant model for transmission rather than require a pre-construction open season
- ◆ The anchor tenants on both of the proposed lines have committed to approximately 50% of the facility capacity.
- ◆ Developers will enter into a bilateral agreement with an anchor customer for 1500 MW for 25 years and then hold an open season to subscribe the remaining 1500 MW

FERC is allowing the approach in consideration of the unique challenges facing location-constrained resources, and will consider using it for future projects on a case-by-case basis

Proposed Quebec-New Hampshire Line (NU, NSTAR, HQ)



Sponsored by Northeast Utilities (NU), NSTAR, and US subsidiary of Hydro Quebec (HQUS)

- ◆ 1,200 MW HVDC line from Quebec to New Hampshire
- ◆ Will allow for export of power from new hydro resources being developed in Quebec
- ◆ Submission for ISO technical approval expected 2011, completion in 2014

Relevance: new non-tariff, cost-based cost recovery model

FERC-approved concept:

- ◆ NU and NSTAR to charge HQUS negotiated rates capped at the cost-based rate with no open season
- ◆ In return, HQUS will receive firm transmission rights for the 1,200MW capacity of the project and sell generation into the ISO New England market via a minimum 20 year power purchase agreement.
- ◆ When completed, ISO New England will have operational control of the facility but the cost of line will not be included in the ISO tariff

Project is an example of a bilateral transmission agreement designed to avoid ISO tariffs.

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Contact Johannes Pfeifenberger, Peter Fox-Penner and Delphine Hou at
johannes.pfeifenberger@brattle.com, peter.fox-penner@brattle.com, delphine.hou@brattle.com
44 Brattle Street, Cambridge, MA 02138 1850 M Street NW, Washington, DC 20036
617-864-7900 202-955-5050



Appendix: “Difficult-to-Quantify” Transmission Benefits

(Discussion of “Other Benefits” Listed on Slide 14)

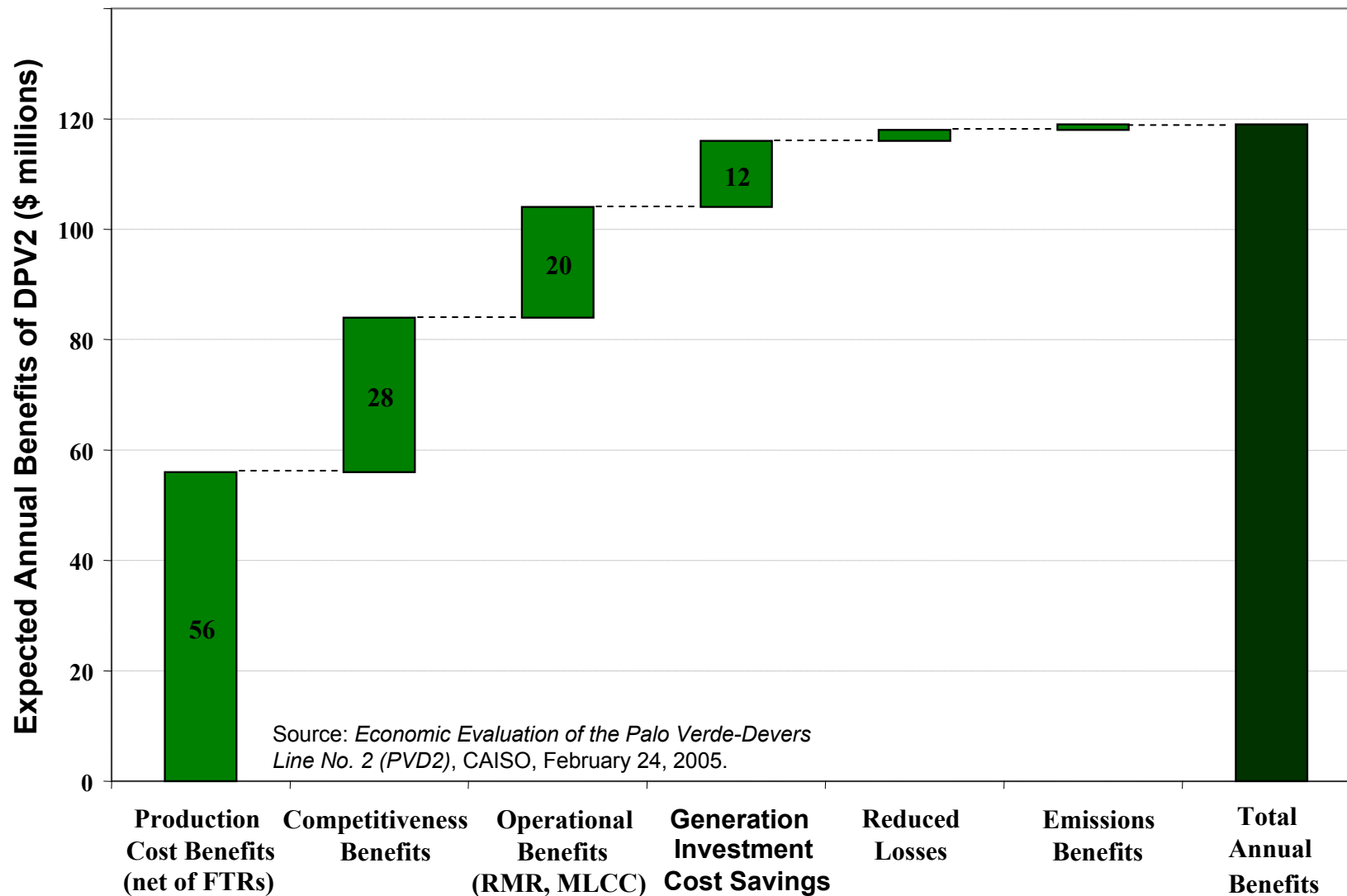
Important Transmission Benefits Often Ignored

Eastern RTO planning processes based on “production cost” studies generally do not assess important benefits:

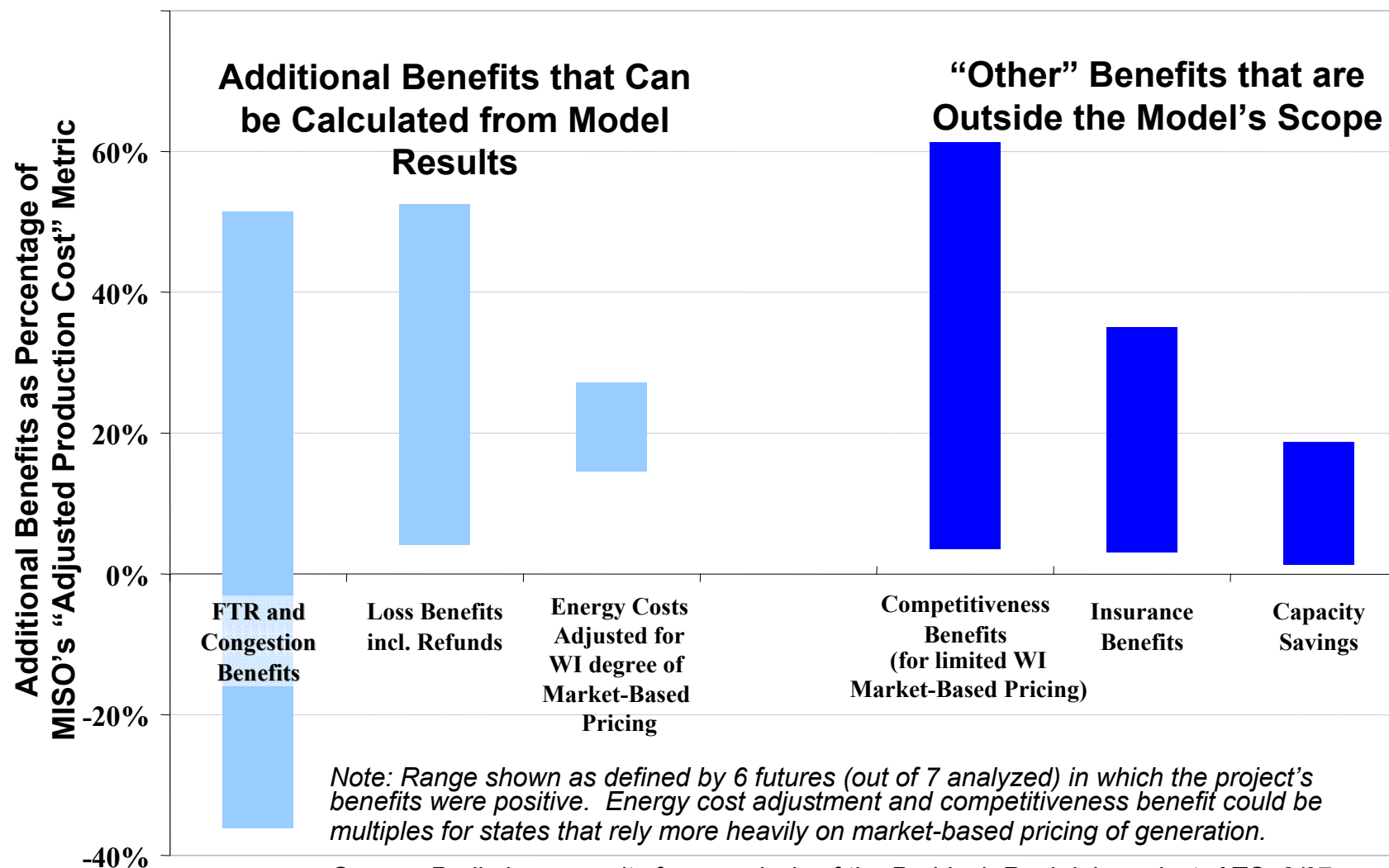
- | | | |
|---|---|---------------------------------------|
| ◆ Enhanced market competitiveness | } | Additional market benefits |
| ◆ Enhanced market liquidity | | |
| ◆ Economic value of reliability benefits | } | Reliability/operational benefits |
| ◆ Added operational and A/S benefits | | |
| ◆ Insurance and risk mitigation benefits | | |
| ◆ Capacity benefits | } | Investment and resource cost benefits |
| ◆ Long-term resource cost advantage | | |
| ◆ Synergies with other transmission projects | | |
| ◆ Impacts on fuel markets | } | External benefits |
| ◆ Environmental and renewable access benefits | | |
| ◆ Economic benefits from construction and taxes | | |

These often omitted transmission-related economic benefits can double benefits quantified in production cost studies. (Potential overlaps create risk of omissions as well as double counting.)

CAISO Example: Total Benefits of DPV2 Were More Than Double its Production Cost Benefits



Example: Adders to Production Cost Savings in Transmission Cost-Benefit Study by *Brattle* and ATC



Source: Preliminary results from analysis of the Paddock-Rockdale project, ATC, 3/07.

Market Competitiveness Benefits

- ◆ **New transmission enhances competition (especially in load pockets) by broadening set of suppliers**
 - Impacts structural measures of market concentration (HHI, PSI)
 - Various approaches are available to translate improvements in these structural measures into potential changes in market prices
 - Size of impact differs in restructured and non-restructured markets
- ◆ **Can substantially reduce market prices during tight market conditions**
 - We found competitiveness benefits can range from very small to multiples of the production cost savings, depending on
 1. fraction of load served by cost-of-service generation
 2. the generation mix and load obligations of market-based suppliers
 - CAISO estimated competitiveness benefits can average 50% to 100% of energy cost benefits (for DPV2 and Path 26 Upgrade), with very wide range (5% to 500%) depending on future market conditions

Market Liquidity Benefits

- ◆ **Limited power market liquidity is costly to participants in both restructured and non-restructured markets**
- ◆ **Added transmission can increase liquidity of trading hubs or allow access to more liquid trading hubs**
 - Lower bid-ask spreads
 - Increased pricing transparency, reduced risk of overpaying
 - Improved risk management
 - Improved long-term planning, contracting, and investment decisions
- ◆ **Quantification is challenging but benefit can be sizeable**
 - Bid-ask spreads for bilateral contracts at less liquid hubs are 50 cents to \$1.50 per MWh higher than at more liquid hubs
 - At transaction volumes of 10 to 100 million MWh per quarter at each of 30+ trading hubs, even a 10 cent reduction of bid-ask spreads saves \$4 to \$40 million per year and trading hub

Reliability Benefits

◆ Reliability has economic value

- Average value of lost load easily exceed \$5,000 to \$10,000 per MWh

Reliability cost = (expected unserved energy) x (value of lost load)

- About 24 outages per year with curtailments in 100-1,000 MW range, 5 in 1,000-10,000 MW range, and 0.25 in 10,000+ MW range

◆ Even “economic” projects tend to improve reliability

- Increases options for recovering from supply disruptions and transmission outages
- For example, DPV2 would reduce load drop requirements of certain extreme contingencies by 2300 MW (i.e., \$10-\$100 million benefit for each avoided event)

◆ Models tend to understate unserved energy

- EUE/LOLP models often consider only generation reliability, not probability of transmission outages
- Dispatch models do not cover full range of possible outcomes; generally also ignore transmission outages and voltage constraints

Added Operational Benefits

- ◆ **New transmission projects can reduce certain reliability-related operating costs**
 - Examples are out-of-merit dispatch costs, reliability-must-run costs, unit commitment costs (RMR, MLCC, RSG, etc.), which can be a multiple of total congestion charges
 - Added transmission can also reduce costs by increasing flexibility for maintenance outages, switching, and protection arrangements
 - Ancillary service benefits
- ◆ **Dispatch models do not generally capture these costs**
 - RMR costs not explicitly considered
 - Ancillary services modeled only incompletely
 - Transmission outages (planned or forced) not generally modeled
- ◆ **CAISO estimated operational benefit of DPV2 would add 35% to energy cost savings**

Insurance and Risk Mitigation Benefits

◆ Even if a range of “scenarios” is simulated in economic analysis, new transmission can offer additional “insurance” benefits

- Helps avoid high cost of infrequent but extreme contingencies (generation or transmission) not considered in scenarios
- Incur premium to diversify resource mix to address risk aversion of customers and regulators

◆ Insurance and risk mitigation value can be quantified:

- Calculate probability-weighted market price and production cost benefits through dispatch simulation of extreme events
- Additional reliability value (EUE x VOLL)
- Potential additional risk mitigation value if project diversifies resource mix and reduces the cost variances across scenarios

In recent case, value of insurance against high energy costs during extreme events (even ignoring reliability and risk premium) added as much as 25% to production cost savings

Capacity Benefits

◆ New transmission can reduce installed capacity and reserve requirements

1. *Reduced system losses during peak load* reduces installed capacity requirement

- On a recently-evaluated transmission project, loss related capacity benefits on average added 5% to 10% to production cost savings.

2. *Added import capability* may improve LOLE and, as a consequence, allow to reduce local reserve margin requirements or satisfy requirement by improving deliverability of resources

- Reduced reserve margin or resource adequacy requirements often difficult to attribute to individual transmission projects
- Still, benefits can be large if a project were to trigger such a reduction (e.g., \$8 million annually if Wisconsin reserve margin requirements could be reduced from 18% to 17%)

Long-term Resource Cost Advantage

- ◆ **Impact of transmission on total resource costs (capital and operating) may not be captured in simulation**
 - Simulations with and without the transmission project, but generally for fixed generation system
 - Dispatch models do not generally capture capital costs of resources nor the facilitation of unique low-cost generating options
- ◆ **New transmission can lower total resource costs**
 - Make feasible physical delivery from generation in remote locations that may offer a variety of cost advantages:
 - lower fuel costs (e.g., mine mouth coal plants)
 - better capacity factors (e.g., renewables from wind-rich areas)
 - lower land, construction, and labor costs
 - access to valuable unique resources (e.g., pumped storage)
 - lower environmental costs (e.g., carbon sequestration options)

Risk: double counting of capacity and congestion cost benefits
- ◆ **Advantage of lower-cost remote resource can exceed higher transmission-related costs (incl. congestion and losses)**

Synergies with Other Transmission Projects

◆ Individual transmission projects can provide significant benefits through synergies with other transmission investments

- For example, construction of DPV2 improves the economics and feasibility of TransWest Express and Project Zia
 - If failure to site DPV2 delays TransWest Express, each year of delay may forego \$200-300 million in low-cost imports to AZ
 - Transmission to access renewables in New Mexico (Project Zia) also may be uneconomic if California markets cannot be reached
- Construction of the Tehachapi transmission project (to access 4,500 MW of wind resources) allows low-cost upgrade of Path 26 and provides additional options for future transmission expansions

◆ Economically justified transmission projects may avoid or delay the need for (or reduce the cost of) future reliability projects

Impacts on Fuel Markets

◆ **Transmission can reduce fuel demand and prices**

- Through dispatch of more efficient plants
- Through integration of resources that don't use the particular fuel.

For example, Western transmission projects (Tehachapi, Frontier, TransWest Express) each have the potential to reduce Southwestern natural gas demand by several percent through additional renewable or clean coal generation

◆ **As a substitute to transporting fuel, transmission projects can benefit fuel transportation markets**

- “Coal by wire” can help reduce railroad rates (e.g., in the West)
- Accessing generation on the unconstrained side of pipelines

◆ **These fuel market benefits can be wide-spread**

- Additional reductions in generation costs and power prices if fuel is on the margin (e.g., natural gas in the Southwest and East Coast)
- All fuel users outside the electric power industry benefit as well

Environmental and Renewable Access Benefits

- ◆ **New transmission can reduce emissions by avoiding dispatch of high-cost, inefficient generation**
 - Can reduce SO₂, NO_x, particulates, mercury, and CO₂ emissions by allowing dispatch of more efficient or renewable generation
 - DPV2 estimated to reduce WECC-wide NO_x emissions from power plants by 390 tons and natural gas use by 6 million MMBtu or 360,000 tons CO₂ per year (worth \$1-10 million/yr)
 - Tehachapi transmission project to access 4,500 MW of renewable (wind) generation
 - Can also be environmentally neutral or even result in displacement of cleaner but more expensive generation (e.g., gas-fired)
- ◆ **Local-only or regional/national benefits?**
 - Reduction in local emissions may be valuable (e.g., reduced ozone and particles in heavily populated areas) irrespective of regional/national impact
 - May not reduce regional/national emissions due to cap and trade but may reduce the cost of allowances and renewable energy credits
- ◆ **Additional Economic benefits of facilitating renewables development (see next slide)**

Economic Benefits from Construction and Taxes

- ◆ **Comprehensive impact analyses may warrant quantification of direct and indirect economic benefits (jobs and taxes):**

- Economic value of construction activities and plant operations
- Increased property taxes for counties
- State taxes on generator profits and natural gas use
- Economic value of facilitating renewables development

Can amount to tens of millions of dollars

- ◆ **These benefits can be important if entities along transmission path do not receive certain other economic benefits of transmission expansion**

- Constructing 1000 MW of wind generation is estimated to create direct employment of 600 FTE jobs with additional 3,000 indirect and induced FTE jobs. (55 direct and 150 indirect and induced jobs during operating years.)