Transmission Cost Allocation:
Principles, Methodologies, and Recommendations

PRESENTED BY
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PREPARED FOR
OMS Cost Allocation
Principles Committee Meeting

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THE Brattle GROUP
Johannes Pfeifenberger, a Principal at The Brattle Group, is an economist with a background in electrical engineering and over twenty-five years of experience in wholesale power market design, renewable energy, electricity storage, and transmission. He also is a Senior Fellow at Boston University’s Institute of Sustainable Energy (BU-ISE), a Visiting Scholar at MIT’s Center for Energy and Environmental Policy Research (CEEPR), and serves as an advisor to research initiatives by the Lawrence Berkeley National Laboratory’s (LBNL’s) Energy Analysis and Environmental Impacts Division and the US Department of Energy’s (DOE’s) Grid Modernization Lab Consortium.

Hannes has analyzed transmission needs, transmission benefits and costs, transmission cost allocations, and transmission-related renewable generation challenges for independent system operators, transmission companies, generation developers, public power companies, and regulatory agencies across North America. He has worked with SPP and its RSC on regional transmission cost allocation reviews and with MISO and OMS on the evaluating cost-allocation alternatives for multi-value transmission projects.

Hannes received an M.A. in Economics and Finance from Brandeis University’s International Business School and an M.S. and B.S. (“Diplom Ingenieur”) in Power Engineering and Energy Economics from the University of Technology in Vienna, Austria.
Introduction and background

The importance of separating two distinct tasks:
- Benefit-cost analysis for approving individual (or synergistic groups of) projects
- Cost allocation for approved portfolios of transmission projects

Experience with quantifying transmission-related benefits

Considerations for cost allocation

Summary and recommendations

Additional reading
Transmission Planning Processes Need Urgent Improvements to be “Future Ready”

Efforts to improve planning processes are urgently needed to fully realize the potential future savings for at least three reasons:

- Transmission projects require at least 5–10 years to plan, develop, and construct; as a result, planning has to start early to more cost-effectively meet the challenges of changing market fundamentals and the nation’s public policy goals in the 2020–2030 timeframe.
- A continued reliance on traditional transmission planning that is primarily focused on reliability and local needs leads to piecemeal solutions instead of developing integrated and flexible transmission solutions that enable the system to meet public policy goals will be more costly in the long run.
- U.S. is in the midst of an investment cycle to replace aging existing transmission infrastructure, mostly constructed in the 1960s and 70s; this provides unique opportunities to create a more modern and robust electricity grid at lower incremental costs and with more efficient use of existing rights-of-way for transmission.

Substantial recent transmission investments focused too narrowly on reliability and local needs have resulted in missed opportunities.

Disagreements over cost allocation have derailed many planning efforts and created barriers to the development of valuable transmission projects.
Key Challenges in U.S. Transmission Planning

Current planning processes do not yield the most valuable transmission infrastructure. Key barriers to doing so are:

1. Most projects are build solely to address **reliability and local needs**; the substantial recent investments in these types of projects now make it more difficult to justify valuable new transmission that could cost-effectively address economic and public policy needs.

2. Planners and policy makers **do not consider the full range of benefits** that transmission investments can provide, understating the expected value of such projects and how these values change over time.

3. Planners and policy makers do not sufficiently account for the **risk-mitigation and option value of transmission** infrastructure that can avoid the potentially high future costs of an insufficiently-robust and insufficiently-flexible transmission grid.

4. Regional **cost allocation** is overly divisive, particularly when applied on a project-by-project (rather than portfolio- or grid-wide) basis.

5. Ineffective **interregional planning processes** are generally unable to identify valuable transmission investments that would benefit two or more regions.
Basic Cost Allocation and Recovery Mechanisms

1) **License plate**: 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 Transmission Owners (TOs) that benefit from a project, even if the project is not owned by the beneficiaries. TOs then recover allocated costs in their License Plate tariffs from own customers.

3) **Postage stamp**: 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 License Plate tariffs.*

4) **Direct assignment**: transmission costs associated with generation interconnection or other transmission service requests are fully or partially assigned to requesting entity.
   *Innovative variance: Tehachapi LCRI (up-front shared funding, later charged back to generators)*

5) **Merchant cost recovery**: 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.

6) **Co-ownership**: benefitting transmission owners co-own the facility (each recovering costs through rate base treatment); one operator; shared transmission rights (often used in WECC)
Disagreements on Cost-Allocation Creates Challenges Even for Clearly-Beneficial Projects

**Easiest:** develop “needed” local and regional transmission projects that do not involve cost allocation (now majority in many regions)

**Harder:** share costs of reliability-driven transmission projects “needed” to meet regional reliability standards

- Most TOs strongly prefer recovering costs associated with their own ratebase
- Policy makers reluctant to pay for transmission that benefit other states

**Hardest:** allocate costs of economic and public policy projects that provide broad regional or interregional benefits (but are “optional” as they are not needed to maintain reliability)

- Fundamentally different future views of the world
  - Planners and policy makers may disagree on the outlook of natural gas costs but they agree the cost exists; not so with carbon or other policy-related benefits, which are often ignored
- Large regional and inter-regional projects for environmental policies pit states that have the policies (often major population centers) against states that don’t (often more remote areas)
- Reluctance to pay for transmission that facilitates out-of-state generation investments with few direct local jobs
Challenges and Solutions: Addressed in Reports on Transmission Planning, Benefit-Cost Analyses, and Cost Allocations

Well-Planned Electric Transmission Saves Customer Costs:
Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future

Toward More Effective Transmission Planning:
Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

Benefits for the 2013 Regional Cost Allocation Review

July 2013

Judy W. Chang
Johannes P. Pfeifenberger
J. Michael Hagger

Link: https://bit.ly/2GU4h7w
Link: https://bit.ly/3jS0PsB
Link: https://bit.ly/3eYBAD6
Recommend 2-step approach:

1. Determine whether projects are beneficial overall, quantifying a broad set of benefits
   - Without quantifying most benefits, many desirable projects will be rejected
   - Benefits that can be allocated precisely may only be a subset of total benefits
   - Avoid temptation to understate benefits in effort to reduce cost allocation to individual study participants

2. Evaluate how the cost of a portfolio of beneficial projects should be allocated based on distribution of benefits
   - Reduces conflict: a broad set of benefits quantified for a portfolio of projects tends to be more stable over time and be distributed more uniformly

Legend:
- **Total Project Benefits**
- **Cost Estimation**
- **Benefit Analysis**
- **Benefit Allocation**
- **Quantified Benefits**
- **Difficult-to-Quantify Benefits**
- **Readily Quantifiable Benefits**

Recommendation: Clearly Separate Benefit-Cost Analysis of Projects from Cost-Allocation of Approved Portfolios
The wide-spread nature of transmission benefits creates challenges in estimating benefits and how they accrue to different users

| ▪ **Broad in scope, providing many different types of benefits** | • Increased reliability and operational flexibility  
• Reduced congestion, dispatch costs, and losses  
• Lower capacity needs and generation costs  
• Increased competition and market liquidity  
• Renewables integration and environmental benefits  
• Insurance and risk mitigation benefits  
• Diversification benefits (e.g., reduced uncertainty and variability)  
• Economic development from G&T investments |
| ▪ **Wide-spread geographically** | • Multiple transmissions service areas  
• **Multiple states** or regions |
| ▪ **Diverse in their effects on market participants** | • **Customers, generators, transmission owners** in regulated and/or deregulated markets  
• Individual market participants may capture one set of benefits but not others |
| ▪ **Occur and change over long periods of time** | • Several decades (50+ years), typically increasing over time  
• Changing with system conditions and future generation and transmission additions  
• Individual market participants may capture different types of benefits at different times |

**Step 1**: Quantify Transmission-Related Benefits for individual Projects (or Synergistic Groups of Projects)
Production Cost Savings, the Most Common Metric, Misses Many Important Transmission-related Benefits

Adjusted Production Costs (APC) is the most widely-used benefit metric for production-cost simulations (e.g., with PROMOD). Standard model output, meant to capture the cost of generating power within an area net of purchases and sales (imports and exports):

\[
\text{Adjusted Production Costs (APC)} = \\
+ \text{Production costs} \text{ (fuel, variable O&M, startup, emission costs of generation within area)} \\
+ \text{Cost of hourly net purchases} \text{ (valued at the area-internal load LMP)} \\
- \text{Revenues from hourly net sales} \text{ (valued at the area-internal generation LMP)}
\]

Limitations:

♦ Assumes no losses, no unhedged congestion costs for delivering generation to load within each area
♦ Does not capture “gains of trade” – the extent that a utility can buy or sell at a better “outside” price
  • Assumes import-related congestion cannot at all be hedged with allocated FTRs
  • Assumes there here are no marginal loss refunds with imports or exports
♦ For simplicity, APC are typically only quantified for “normal” base-case conditions with perfect foresight
  • No transmission outages (every transmission element is assumed 100% available all the time)
  • Only “normal” conditions (weather-normalized loads, only “normal” generation outages)
  • No consideration of renewable generation uncertainty, change in A/S needs, reduction in transmission losses, fixed O&M cost of increased generation cycling, etc.
♦ Does not capture any investment-related (capacity cost) and risk-mitigation (insurance value) benefits
Good News: We have a Decade of Experience with Identifying and Quantifying a Broad Range of Transmission-related Benefits

SPP 2016 RCAR, 2013 MTF

Quantified
1. production cost savings*
   - value of reduced emissions
   - reduced ancillary service costs
2. avoided transmission project costs
3. reduced transmission losses*
   - capacity benefit
   - energy cost benefit
4. lower transmission outage costs
5. value of reliability projects
6. value of mtg public policy goals
7. Increased wheeling revenues

Not quantified
8. reduced cost of extreme events
9. reduced reserve margin
10. reduced loss of load probability
11. increased competition/liquidity
12. improved congestion hedging
13. mitigation of uncertainty
14. reduced plant cycling costs
15. societal economic benefits

(MISO MVP Analysis)

Quantified
1. production cost savings*
2. reduced operating reserves
3. reduced planning reserves
4. reduced transmission losses*
5. reduced renewable generation investment costs
6. reduced future transmission investment costs

Not quantified
7. enhanced generation policy flexibility
8. increased system robustness
9. decreased natural gas price risk
10. decreased CO₂ emissions output
11. decreased wind generation volatility
12. increased local investment and job creation

(CAISO TEAM Analysis)

Quantified
1. production cost savings*
   - value of reduced emissions
   - reduced ancillary service costs
2. mitigating market power
3. insurance value for high-impact low-probability events
4. capacity benefits due to reduced generation investment costs
5. operational benefits (RMR)
6. reduced transmission losses*
7. emissions benefit

Not quantified
8. facilitation of the retirement of aging power plants
9. encouraging fuel diversity
10. improved reserve sharing
11. increased voltage support

(NYISO PPTN Analysis)

Quantified
1. production cost savings*
   - value of reduced emissions
   - reduced ancillary service costs
2. mitigating market power
3. insurance value for high-impact low-probability events
4. capacity benefits due to reduced generation investment costs
5. operational benefits (RMR)
6. reduced transmission losses*
7. emissions benefit

Not quantified
5. protection against extreme market conditions
6. increased competition and liquidity
7. storm hardening and resilience
8. expandability benefits

* Fairly consistent across RTOs

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

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<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>Transmission Benefit</th>
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</thead>
<tbody>
<tr>
<td>Traditional Production Cost Savings</td>
<td>Production cost savings as currently estimated in most planning processes</td>
</tr>
<tr>
<td>1. Additional Production Cost Savings</td>
<td>a. Impact of generation outages and A/S unit designations</td>
</tr>
<tr>
<td></td>
<td>b. Reduced transmission energy losses</td>
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<tr>
<td></td>
<td>c. Reduced congestion due to transmission outages</td>
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<td></td>
<td>d. Mitigation of extreme events and system contingencies</td>
</tr>
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<td></td>
<td>e. Mitigation of weather and load uncertainty</td>
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<td></td>
<td>f. Reduced cost due to imperfect foresight of real-time system conditions</td>
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<td></td>
<td>g. Reduced cost of cycling power plants</td>
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<td></td>
<td>h. Reduced amounts and costs of operating reserves and other ancillary services</td>
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<tr>
<td></td>
<td>i. Mitigation of reliability-must-run (RMR) conditions</td>
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<td></td>
<td>j. More realistic “Day 1” market representation</td>
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<tr>
<td>2. Reliability and Resource Adequacy</td>
<td>a. Avoided/deferred reliability projects</td>
</tr>
<tr>
<td>Benefits</td>
<td>b. Reduced loss of load probability or c. reduced planning reserve margin</td>
</tr>
<tr>
<td>3. Generation Capacity Cost Savings</td>
<td>a. Capacity cost benefits from reduced peak energy losses</td>
</tr>
<tr>
<td></td>
<td>b. Deferred generation capacity investments</td>
</tr>
<tr>
<td></td>
<td>d. Access to lower-cost generation resources</td>
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<tr>
<td>4. Market Benefits</td>
<td>a. Increased competition</td>
</tr>
<tr>
<td></td>
<td>b. Increased market liquidity</td>
</tr>
<tr>
<td>5. Environmental Benefits</td>
<td>a. Reduced emissions of air pollutants</td>
</tr>
<tr>
<td></td>
<td>b. Improved utilization of transmission corridors</td>
</tr>
<tr>
<td>6. Public Policy Benefits</td>
<td>Reduced cost of meeting public policy goals</td>
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<tr>
<td>7. Employment and Economic</td>
<td>Increased employment and economic activity;</td>
</tr>
<tr>
<td>Stimulus Benefits</td>
<td>Increased tax revenues</td>
</tr>
<tr>
<td></td>
<td>Examples: storm hardening, fuel diversity, flexibility, reducing the cost of future</td>
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<tr>
<td></td>
<td>transmission needs, wheeling revenues, HVDC operational benefits</td>
</tr>
<tr>
<td>8. Other Project-Specific Benefits</td>
<td>Examples: storm hardening, fuel diversity, flexibility, reducing the cost of future</td>
</tr>
<tr>
<td></td>
<td>transmission needs, wheeling revenues, HVDC operational benefits</td>
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</tbody>
</table>
Example: Transmission Benefits and Costs in Wisconsin

ATC’s Paddock-Rockdale Project study: Total benefits significantly exceed production cost savings

Total benefits of CAISO’s DPV2 project exceeded project costs by more than 50%, but only if multiple benefits are quantified.

Example: New York’s (Multi-Value) “Public Policy” Transmission Planning Process

New York DPS recently modified its “public policy” transmission planning process by mandating that a full set of benefits be considered. Resulted in approval and competitive solicitation of two major upgrades to the New York transmission infrastructure.

Summary of Quantified Benefits and Costs
(additional benefits considered qualitatively)

Step 2: Portfolio-Based Cost Allocations offer Substantial Advantages over Project-by-Project Allocations

Order 1000 does not require that the cost of each project is allocated based on its benefits ... as long as the cost allocation for a portfolio of projects is roughly commensurate with overall benefits. Even postage stamp (load-ratio share) allocation is appropriate and acceptable if:

- All customers tend to benefit from class or group of facilities
- Distribution of benefits likely to vary over long life of facilities

Portfolio-based cost allocations are less controversial and easier to implement

- Portfolio-wide benefits tend to be more even distributed and more stable over time
- One cost allocation analysis for portfolio vs. many analyses for many projects

Examples of portfolio-based cost allocations:

- SPP Highway-Byway (designed by RSC): Periodic review if benefits of all approved projects is roughly commensurate with costs of all projects
- MISO MVPs (with OMS input): Benefits of entire portfolio compared with allocated costs
SPP’s “RCAR” Experience: More Uniform Total Benefits for Large Portfolio Evaluated with Multiple Benefits Metrics

SPP’s Regional Cost Allocation Reviews show (1) B-C Ratios of SPP’s ITP Portfolio has grown over time and (2) provides members with total benefits that exceeds their allocated costs in most cases

- Done every few years for all ITP projects approved to date
- Evaluation of entire ITP portfolio makes quantification of multiple benefits metrics possible

MISO’s MVP Analyses: Benefits of the Portfolio (as a Whole) Significantly Exceed Postage-Stamp-Allocated Costs in all Regions

MISO’s MVP Portfolio provides benefits across the MISO footprint that are roughly equivalent to (postage-stamp) allocated costs

- MISO quantified 6 types of economic benefits (plus reliability and public policy benefits)

- MTEP17 analysis shows $22 to $75 billion in total benefits to MISO North and Central

- Total costs increased from $5.6 to $6.7 billion, but benefits grew even more

- B-C ratios exceed 1.5 to 2.6 in every zone

Cost Allocation Alternatives Developed in 2010 by MISO and OMS for $29 billion RGOS Transmission Overlay

Brattle supported MISO and OMS in analyzing various cost allocation proposals for the $29 billion RGOS portfolio. Final proposal used injection-withdrawal approach:

- Costs allocated to injections and withdrawals based on local and regional usage
- Ultimately replaced with MVP postage stamp (due to TO and generator preference)

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<thead>
<tr>
<th>Layer</th>
<th>Local</th>
<th>Regional</th>
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</thead>
<tbody>
<tr>
<td>Central below 345 kV</td>
<td>55%</td>
<td>45%</td>
</tr>
<tr>
<td>Central 345 kV</td>
<td>48%</td>
<td>52%</td>
</tr>
<tr>
<td>Eastern below 345 kV</td>
<td>64%</td>
<td>36%</td>
</tr>
<tr>
<td>Eastern 345 kV</td>
<td>59%</td>
<td>41%</td>
</tr>
<tr>
<td>Western below 345 kV</td>
<td>43%</td>
<td>57%</td>
</tr>
<tr>
<td>Western 345 kV</td>
<td>27%</td>
<td>73%</td>
</tr>
<tr>
<td>MISO-wide above 345 kV*</td>
<td>6%</td>
<td>94%</td>
</tr>
</tbody>
</table>

*For facilities above 345 kV, usage percentages determined for overall footprint.

- MISO engineering study determined how much of the grid is used for local (within zone) and regional (MISO-wide) transmission
- **Local charges** on $/MW shared between loads and generators within pricing zone
- **Regional charges** on $/MWh basis to all loads and exports
- Generation Interconnection Projects pay the higher of (a) the local portion of network upgrade costs and (b) the local access rate

Summary and Recommendations

Benefit-cost analyses and cost allocations can be improved to offer more cost-effective and less controversial outcomes:

- More fully consider broad range of reliability, economic, and public-policy benefits, including experience gained through:
  - SPP value of transmission and RCAR benefits metrics
  - NYISO broad set of benefits quantified for public policy projects
  - MISO MVP benefits; CAISO economic and public policy projects

- Reduce divisiveness of cost allocation through broad set of portfolio-based benefits
  - Recognize broad range of benefits → more likely to be evenly distributed and exceed costs
  - Focus on larger portfolios of transmission projects → more uniform distribution of benefits
  - Broad range of benefits for a portfolio will also be more stable over time

In addition: Focus less on addressing near-term reliability and local needs, but more on infrastructure that provides greater flexibility and higher long-term value at lower system-wide cost
  - Recognize that every transmission project offers multiple values
  - Lowest-cost transmission is not “least cost” from an overall customer-cost perspective
Additional Reading


Our Practices and Industries

ENERGY & UTILITIES
- Competition & Market Manipulation
- Distributed Energy Resources
- Electric Transmission
- Electricity Market Modeling & Resource Planning
- Electrification & Growth Opportunities
- Energy Litigation
- Energy Storage
- Environmental Policy, Planning and Compliance
- Finance and Ratemaking
- Gas/Electric Coordination
- Market Design
- Natural Gas & Petroleum
- Nuclear
- Renewable & Alternative Energy

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- Bankruptcy & Restructuring
- Big Data & Document Analytics
- Commercial Damages
- Environmental Litigation & Regulation
- Intellectual Property
- International Arbitration
- International Trade
- Labor & Employment
- Mergers & Acquisitions
- Product Liability
- Securities & Finance
- Tax Controversy & Transfer Pricing
- Valuation
- White Collar Investigations & Litigation

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