MISO South Tranche 3 Transmission Planning and Cost Allocation

PRESENTED BY
Michael Hagerty
John Tsoukalis

PREPARED FOR
Entergy Regional State Committee (ERSC)

September 2023
Contents

1. Need for Improved Transmission Planning
2. Quantifying Cost Savings and Other Benefits of Transmission
3. Transmission Cost Allocation
4. Perspective on E-RSC Principles

Appendix: Additional Resources
1. Identifying the Need for Improved Transmission Planning
Transmission Investment is at Historically High Levels

$20-25 billion in annual U.S. transmission investment, but:

- More than 90% justified solely for reliability needs
  - About 50% based on “local” utility criteria (without going through regional planning processes)
  - The rest justified by regional reliability and generation interconnection needs
- Very few projects justified based on economics and overall cost savings, despite significant experience with transmission benefit-cost analyses

Current planning processes do not yield the most valuable and cost effective transmission infrastructure and result in **higher overall ratepayer costs**:

- **Reactive, reliability-driven planning** results in piecemeal, higher-cost transmission solutions
  - For example: PJM generation interconnection studies for 15.5 GW of individual offshore wind plants identified $6.4 billion in onshore transmission upgrades
  - In contrast: A recent PJM study that proactive evaluated onshore upgrade needs for 17 GW of offshore wind (along with 14.5 GW of onshore wind and 45.6 GW of solar) identified only $3.2 billion in onshore upgrades
  - Result: **at least 50% lower costs** if renewable interconnection is planned proactively for the entire region’s public policy needs (rather than one project at the time through the generation interconnection process)

- **Failure to evaluate multiple benefits** of transmission projects does not result in the selection of the highest-value projects that reduce system-wide costs

- **Failure to evaluate full range of plausible futures** that explicitly account for long-term uncertainties results in higher-cost outcomes when the future deviates from base case planning assumptions

- **Failure to consider interregional transmission solutions** result in higher-cost regional and local transmission investments
Barriers to Regional and Interregional Transmission Planning

We identified the following barriers to cost effective planning based on interviews with policy makers, regulators, transmission planners & developers, industry groups, environmental groups, and large customers:

### A. Leadership, Alignment and Understanding
1. Insufficient leadership from RTOs and policy makers to prioritize planning
2. Limited trust amongst states, RTOs, utilities, & customers
3. Limited understanding of transmission issues, benefits & proposed solutions
4. Misaligned interests of RTOs, TOs, generators & policymakers
5. States prioritize local interests, such as development of in-state renewables

### B. Planning Process and Analytics
6. Benefit analyses are too narrow, and often not consistent between regions
7. Lack of proactive planning for a full range of future scenarios
8. Sequencing of local, regional, and interregional planning
9. **Cost allocation (too contentious or overly formulaic)**

### C. Regulatory Constraints
10. Overly-prescriptive tariffs and joint operating agreements
11. State need certification, permitting, and siting

Source: Appendix A of *A Roadmap to Improved Interregional Transmission Planning*, November 30, 2021.
Transmission Planning for the 21st Century

Available industry experience already points to proven transmission planning practices that reduce total system costs and risks:

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix and load levels and shapes over the lifespan of the transmission investment.

2. **Account for the full range of transmission projects’ cost savings** and **use multi-value planning** to comprehensively identify investments that cost-effectively address all categories of needs and benefits.

3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that accounts for a broad range of plausible long-term futures as well as real-world system conditions.

4. **Use comprehensive transmission network portfolios** to address system needs and **cost allocation** more efficiently and less contentiously than a project-by-project approach.

5. **Jointly plan inter-regionally across neighboring systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

2. Quantifying Transmission Cost Savings and Other Benefits
Understanding Transmission Cost Savings and Other Benefits

The wide-spread nature of transmission impacts creates challenges in estimating cost savings and how they accrue to different users, which also complicates cost allocation.

| **Broad in scope, providing many different types of cost savings and other benefits** | • Increased reliability and operational flexibility  
• **Reduced congestion, dispatch costs, and losses** *(primary metric in MEP studies)*  
• 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 |
Quantifying Benefits Beyond “Production Cost” Savings

Relying solely on Adjusted Production Cost (APC) Savings in economic planning studies results in the rejection of cost-effective projects and higher overall ratepayer costs.

Source: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (brattle.com)
Over 10 Years of Industry Experience with Identifying and Quantifying a Broad Range of Transmission Benefits

**MISO MVP Analysis**

**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

**CAISO TEAM Analysis**

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

**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

**NYISO PPTN Analysis**

(AC Upgrades)

**Quantified**
1. **production cost savings**
2. capacity resource cost savings
3. reduced refurbishment costs for aging transmission
4. reduced costs of achieving renewable and climate policy goals

**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*
New York’s Multi-Value Transmission Planning Process

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

Avoided cost of future replacement of aging transmission infrastructure and future reliability projects cover up to half of some of the public policy projects’ costs.

Inadequate Transmission Creates High Risk of Costly Outcomes in Both Short- and Long-term

Most transmission planning efforts do not adequately account for short- and long-term risks and uncertainties affecting power markets

- **Short-Term Risks:** transmission planning generally evaluates only “normal” system conditions
  - Planning process typically ignores the high cost of short-term challenges and extreme market conditions triggered by high-impact-low-probability ("HILP") events due to weather, transmission outages, fuel supply disruption, or unexpected load changes associated with economic booms/busts
  - Can be addressed through modeling assumptions and sensitivities that capture these short-term challenges

- **Long-Term Risks:** Planning does not adequately consider the full range of long-term scenarios
  - Does not capture the extent to which a less robust and flexible transmission infrastructure will help reduce the risk of high-costs incurred under different (long-term) future market fundamentals
  - Can be addressed through improved scenario planning that covers the full range of plausible futures

A more flexible and robust grid provides “insurance value” by reducing the risk of high-cost (short- and long-term) outcomes due to inadequate transmission

- Costs of inadequate infrastructure (typically are not quantified) can be much greater than the costs of the transmission investment
- Project may not quite be cost effective in “base case” future but be highly beneficial in 3 out of 5 futures
3. Transmission Cost Allocation
Disagreements on Cost-Allocation Creates Barriers Even for Clearly-Beneficial Projects

**Easiest**: local and regional *reliability* and generation interconnection transmission projects that do not involve cost sharing (now majority in many regions)

**Harder**: regional reliability projects with regional cost sharing
- Most TOs strongly prefer recovering costs associated with their own ratebase
- Policy makers reluctant to pay for transmission that benefit other states

**Hardest**: regional economic or public-policy projects with shared costs
- Disagreement on which cost savings and other benefits to quantify and how “real” they are
- Parties may have fundamentally different future views of the world
- Reluctance to pay for transmission that facilitates out-of-state generation investments with few direct local jobs

**Almost Impossible**: interregional projects; but mostly hypothetical because no significant interregional projects have been planned in the last decade
Basic Cost Allocation and Recovery Mechanisms

1) License Plate: each utility locally recovers the costs of its transmission investments (usually located within its footprint). Example: used for all MISO “reliability” and all RTOs’ “local” projects.

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: costs recovered uniformly from all loads in a defined market area
   - RTO-wide examples: ERCOT, >200kV in CAISO, >115kV in ISO-NE, MVPs in MISO
   - SPP Highway/Byway: postage stamp for all ITP projects >300 kV (hybrid PS/LP approach for lower voltage)

4) Direct Assignment/Participant Funding: 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); more common with HVDC lines

6) Co-ownership: benefitting transmission owners co-own the facility (each recovering costs through rate base treatment); one operator; shared transmission rights (e.g., CAPX 2020; often used in WECC)
Recommends 2-step approach for addressing transmission system needs:

1. Determine whether projects are beneficial overall based on a broad set of benefits
   - Many cost effective projects will be rejected without quantifying most cost savings and other benefits
   - 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 to allocate the costs of a portfolio of projects based on their joint 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
Portfolio-Based 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 is likely to vary (but “average out”) 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
2011 MVP Projects Provide Sufficient Portfolio-Wide Benefits of that Exceed Postage-Stamp-Allocated Costs in all Regions

MVP Portfolio provides benefits across the MISO North & Central footprints that are roughly equivalent to postage-stamp-allocated costs

- 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

SPP RCAR: 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) total benefits exceed their allocated costs in most cases

- Cost allocation review done every few years for all approved ITP projects
- Evaluation of entire ITP portfolio makes quantification of multiple benefits metrics possible

<table>
<thead>
<tr>
<th>Metric</th>
<th>RCAR I (2013$)</th>
<th>RCAR II (2016$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APC Savings</td>
<td>$3,020</td>
<td>$8,974</td>
</tr>
<tr>
<td>Assumed Benefit of Mandated Reliability Projects</td>
<td>$2,475</td>
<td>$5,759</td>
</tr>
<tr>
<td>Mitigation of Transmission Outage Costs</td>
<td>$340</td>
<td>$1,014</td>
</tr>
<tr>
<td>Capacity Savings from Reduced On-Peak Losses</td>
<td>$155</td>
<td>$7,431</td>
</tr>
<tr>
<td>Increased Wheeling Through and Out Revenues</td>
<td>Not Monetized</td>
<td>$641</td>
</tr>
<tr>
<td>Marginal Energy Losses Benefits</td>
<td>Not Monetized</td>
<td>$427</td>
</tr>
<tr>
<td>Avoided or Delayed Reliability Projects</td>
<td>$97</td>
<td>$41</td>
</tr>
<tr>
<td>Benefit from Meeting Public Policy Goals</td>
<td>$296</td>
<td>$0</td>
</tr>
<tr>
<td>Reduced Cost of Extreme Events</td>
<td>Not Monetized</td>
<td>Not Monetized</td>
</tr>
<tr>
<td>Reduced Loss of Load Probability</td>
<td>Not Monetized</td>
<td>Not Monetized</td>
</tr>
<tr>
<td>Capital Savings from Reduced Minimum Required Margin</td>
<td>Not Monetized</td>
<td>Not Monetized</td>
</tr>
<tr>
<td>Total Benefits (PV of 40-y Benefits for 2015-2054)</td>
<td>$6,383</td>
<td>$17,599</td>
</tr>
<tr>
<td>Total Portfolio Cost (PV of 40-y ATRR)</td>
<td>$4,581</td>
<td>$7,180</td>
</tr>
</tbody>
</table>

5. Summary and Recommendations
### Perspective on E-RSC Principles based on Industry Experience

<table>
<thead>
<tr>
<th>E-RSC Principle</th>
<th>Experience from other Jurisdictions</th>
</tr>
</thead>
</table>
| **No Postage Stamp**          | • Provides a simple and consistent approach to approving cost-effective projects  
                                  • Shown to be roughly commensurate with benefits for higher voltage lines in SPP and MISO North/Central  
                                  • May risk over-allocation to regions with low benefits, which can be mitigated by evaluating region-specific BCAs and putting a mechanism in place to adjust cost allocation as needed |
| **Granular and Accurate Allocation** | • Requires a broader view of cost savings and other benefits than MEP to accurately capture impacts  
                                  • Formulaic approaches are heavily assumption-based, not stable to evolving conditions, and easily contested  
                                  • Tends to result in under-investment in cost-effective projects and contentious litigation (e.g., PJM’s DFX)                                                                 |
| **Cost Causation and Beneficiary Pays** | • Multiple cost allocation approaches can be consistent with “roughly commensurate” standard  
                                  • Need to weigh accuracy with risk of underinvestment                                                                                                                                 |
| **Equitable**                 | • Necessary to build trust in the cost allocation process                                                                                                                                                                           |
| **Interconnecting Resources Pay** | • Can be successfully deployed for lines specifically design to access low-cost resources (see Tehachapi)  
                                  • May be difficult to accurately quantify interconnection cost savings of some network upgrades                                                                                                               |
| **Accurate and Replicable Metrics** | • Significant industry experience in quantifying a broad set of cost savings and other benefits  
                                  • Address uncertainties and high-stress grid conditions explicitly through scenario-based planning  
                                  • Can be tuned to the highest value set of metrics based on specific market conditions in MISO South  
                                  • Local specification of benefit metrics can help foster trust in the final cost allocation outcomes                                                                 |
| **Defined by E-RSC**          |                                                                                                                                                                                                                                     |
| **Non-Portfolio**             | • Portfolio approach can produce larger benefits and help reduce disputes related to cost allocation                                                                                                                                 |

**brattle.com | 21**
Summary and Recommendations

Broadly apply proven planning practices that reduce total system costs and risks:

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.

2. **Account for the full range of transmission projects’ benefits** and use **multi-value planning** to comprehensively identify investments that cost-effectively address all categories of needs and benefits.

3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.

4. **Use comprehensive transmission network portfolios** to address system needs and **cost allocation** more efficiently and less contentiously than a project-by-project approach.

5. **Jointly plan inter-regionally across neighboring systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.
Michael Hagerty specializes in planning and regulatory matters related to the electric power system in an increasingly decarbonized future. His expertise includes long-term generation and storage resource planning, transmission planning and development, and electrification of transportation and heating. Mr. Hagerty has experience working on matters related to electric vehicle adoption and system impact analysis; renewable resource, generation, and storage asset valuation; decarbonization policies; and transmission benefit-cost analysis.

He has assisted a wide range of stakeholders – including electric utilities, generation and transmission developers, state agencies and commissions, automakers, and regional transmission organizations (RTOs) – in understanding and evaluating strategic questions related to the clean energy transition. This has included planning the buildout of the transmission network, assessing the future generation resource mix, and analyzing the pace and impact of electric vehicle (EV) and heating electrification adoption. He has also forecasted scenarios for the deployment of EV charging infrastructure necessary to meet increasing demand and customer adoption of greenhouse gas-reducing technologies, such as electric heat pumps, energy efficiency, and rooftop solar.

Mr. Hagerty has submitted testimony to state and federal commissions related to generation resource additions to achieve decarbonization goals, electric vehicle infrastructure needs, transmission planning processes and benefits analysis, and electricity market design. For the US Department of Energy, he has reviewed and outlined major issues facing the country’s electric power infrastructure.

The views expressed in this presentation are strictly those of the presenter(s) and do not necessarily state or reflect the views of The Brattle Group or its clients.
John Tsoukalas, is a Principal at The Brattle Group specializing in electric power sector economics, modeling, and regulation. John has worked with Independent System Operators (ISO), Regional Transmission Organizations (RTO), cooperatives, public power authorities, and investor-owned utilities on a wide range of issues related to wholesale power markets. His expertise includes analyzing and designing alternative transmission rate designs, assessing the effectiveness of transmission planning processes and designing improvements to planning processes, conducting benefit-cost analysis of generation and transmission infrastructure, assessing the value of transmission rights, analyzing the effectiveness of transmission cost allocation processes, and helping transmission developers to analyze investment opportunities in the US and Canada.

John’s experience extends to conducting nodal production cost and power flow simulations of wholesale markets and regional power systems. His work in this area has been used to assess the benefits of transmission infrastructure, participation in wholesale power markets, joint regional unit commitment and/or dispatch, a joint regional transmission tariff, and consolidated balancing area operations. He has conducted production cost simulation models to value regional transmission infrastructure and trading rights, assess the operation of regional transmission systems, analyze the operation and value of generation assets in bilateral and organized regional power markets, and for the assessment of potential market manipulation and market power abuse in wholesale power markets. John has extensive experience helping ISOs/RTOs and utility clients analyze and design market rules to increase the efficiency of existing wholesale market operations, including the design of transmission charges, operating reserve products, and market power mitigation rules and procedures.

The views expressed in this presentation are strictly those of the presenter(s) and do not necessarily state or reflect the views of The Brattle Group or its clients.
Additional Reading on Transmission

Brattle Group 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

**LITIGATION**
- Accounting
- Analysis of Market Manipulation
- Antitrust/Competition
- Bankruptcy & Restructuring
- Big Data & Document Analytics
- Commercial Damages
- Environmental Litigation & Regulation
- Intellectual Property
- International Arbitration
- International Trade
- Labor & Employment
- Mergers & Acquisitions Litigation
- Product Liability
- Securities & Finance
- Tax Controversy & Transfer Pricing
- Valuation
- White Collar Investigations & Litigation

**INDUSTRIES**
- Electric Power
- Financial Institutions
- Infrastructure
- Natural Gas & Petroleum
- Pharmaceuticals & Medical Devices
- Telecommunications, Internet, and Media
- Transportation
- Water
Our Offices

BOSTON

BRUSSELS

CHICAGO

LONDON

MADRID

NEW YORK

ROME

SAN FRANCISCO

SYDNEY

TORONTO

WASHINGTON, DC