MISO South Tranche 3 Transmission Planning and Cost Allocation

PRESENTED BY

Michael Hagerty

John Tsoukalis

PREPARED FOR

Entergy Regional State Committee (ERSC)

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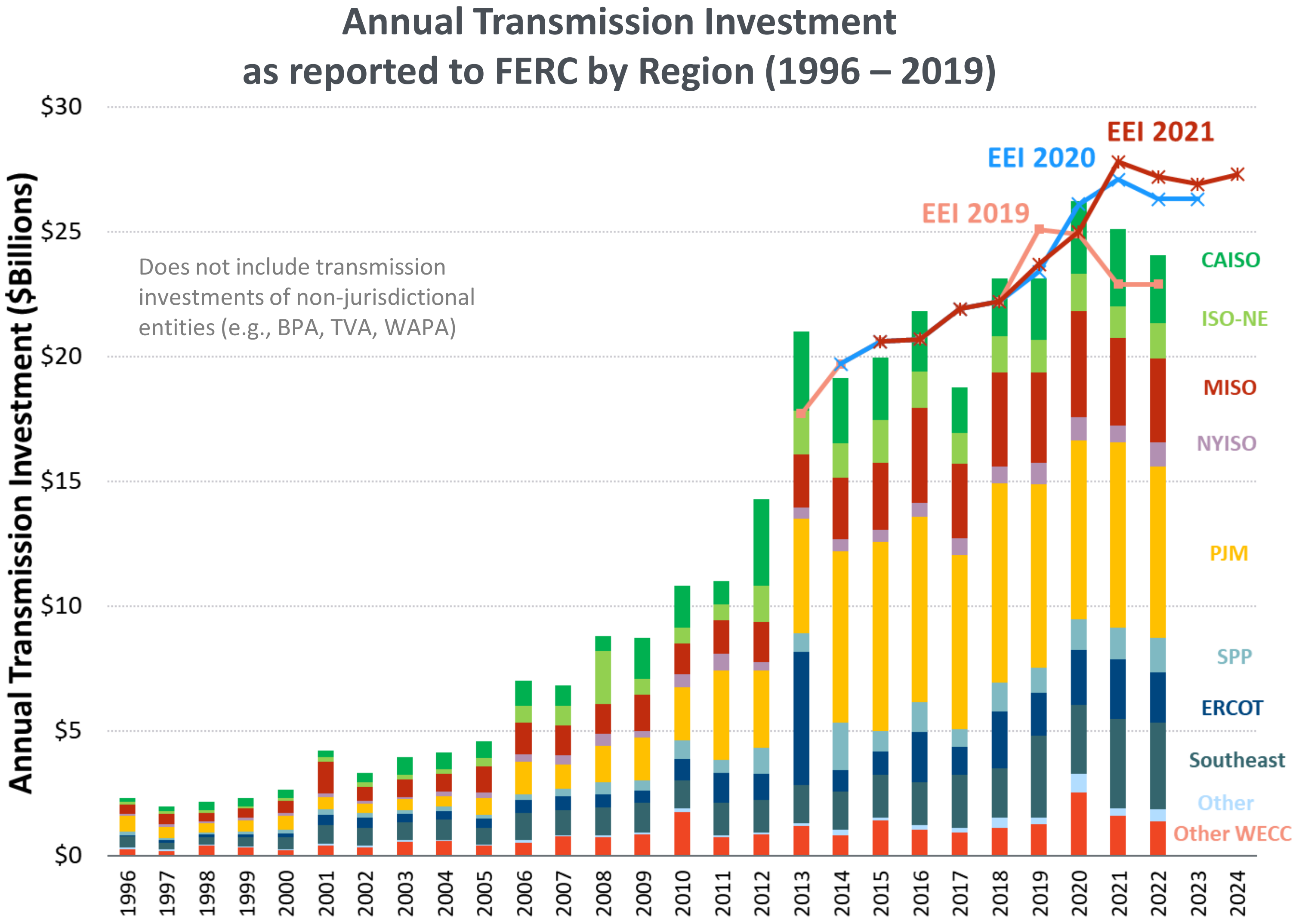
Brattle

Contents

1. Identifying the Need for Improved Transmission Planning

Transmission Investment is at Historically High Levels



Sources: The Brattle Group analysis of FERC Form 1 Data; EEI "Historical and Projected Transmission Investment" most recent accessed here: https://www.eei.org/resourcesandmedia/Documents/Historical%20and%20Projected%20Transmission%20Investment.pdf

$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 U.S. Transmission Planning = Higher Total Costs

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

Key Issues for E-RSC to Address for LRTP

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

See Brattle & Grid Strategies Report: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

2. Quantifying Transmission Cost Savings and Other Benefits

Understanding Transmission Cost Savings and Other Benefits

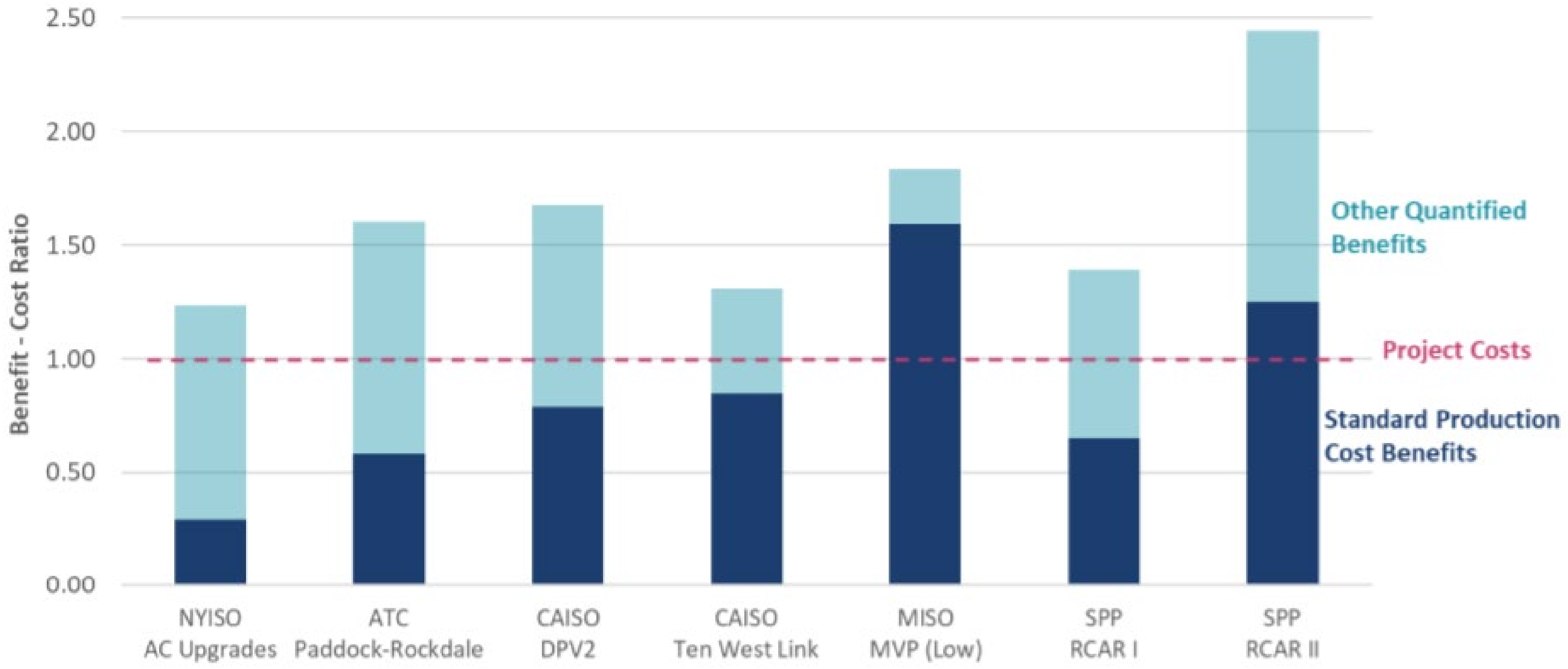
The wide-spread nature of transmission impacts creates challenges in estimating cost savings and how they accrue to different users, which also complicates cost allocation

Broad in scope, providing many <u>different types</u> 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
<u>Wide-spread</u> geographically	• Multiple transmissions service areas • Multiple states or regions
<u>Diverse</u> 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 <u>change</u> 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 <u>Adjusted Production Cost</u> (APC) Savings in economic planning studies results in the rejection of cost-effective projects and higher overall ratepayer costs

FIGURE 5. BENEFIT-COST RATIOS OF TRANSMISSION PROJECTS WITH AND WITHOUT A BROAD SCOPE OF BENEFITS



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

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

(SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.)

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 CO_2 emissions output
11. decreased wind generation volatility
12. increased local investment and job creation

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

CAISO TEAM Analysis

(DPV2 example)

Quantified

1. **production cost savings*** and reduced energy prices from both a societal and customer perspective
2. mitigation of 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

(CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity)

NYISO PPTN Analysis

(AC Upgrades)

Quantified

1. **production cost savings*** (includes savings not captured by normalized simulations)
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

(Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015)

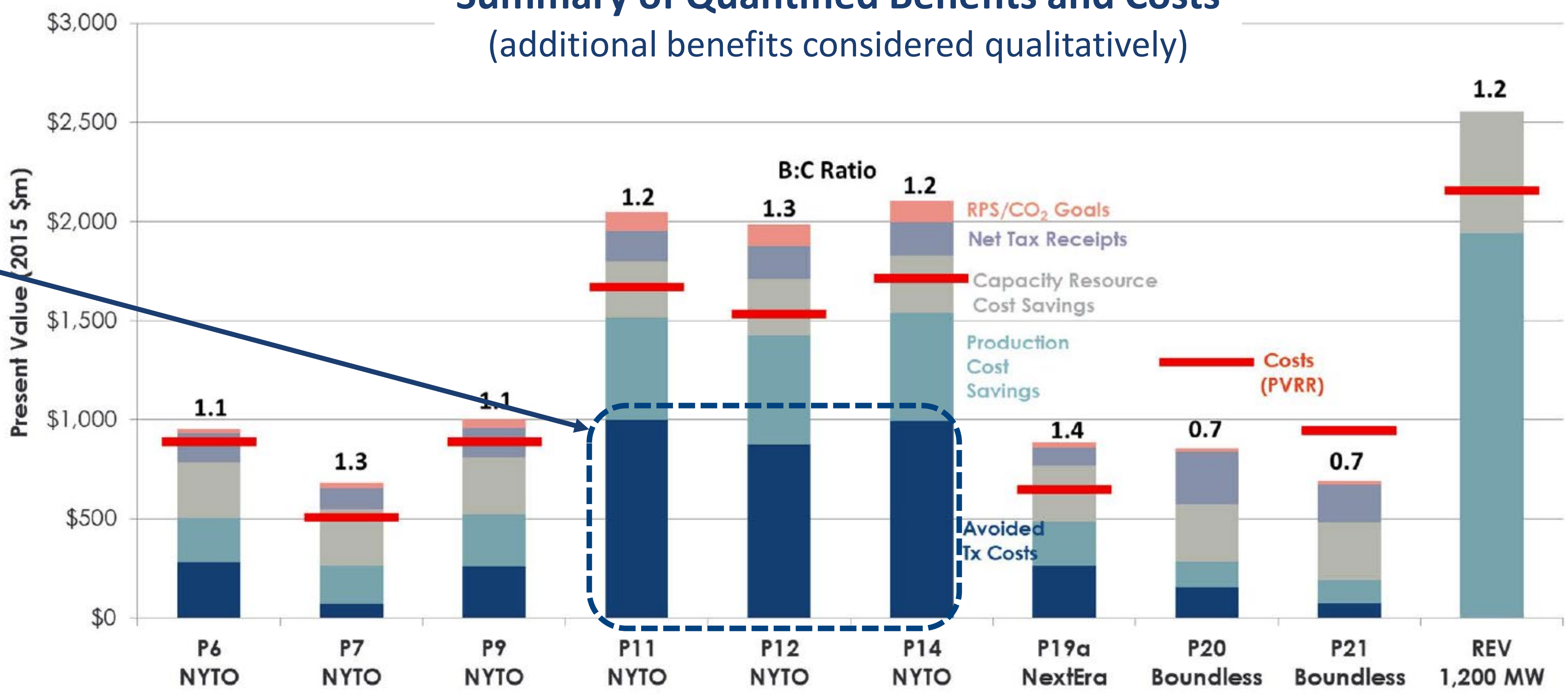
* Fairly consistent across RTOs

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

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



Source: "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," September 15, 2015

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

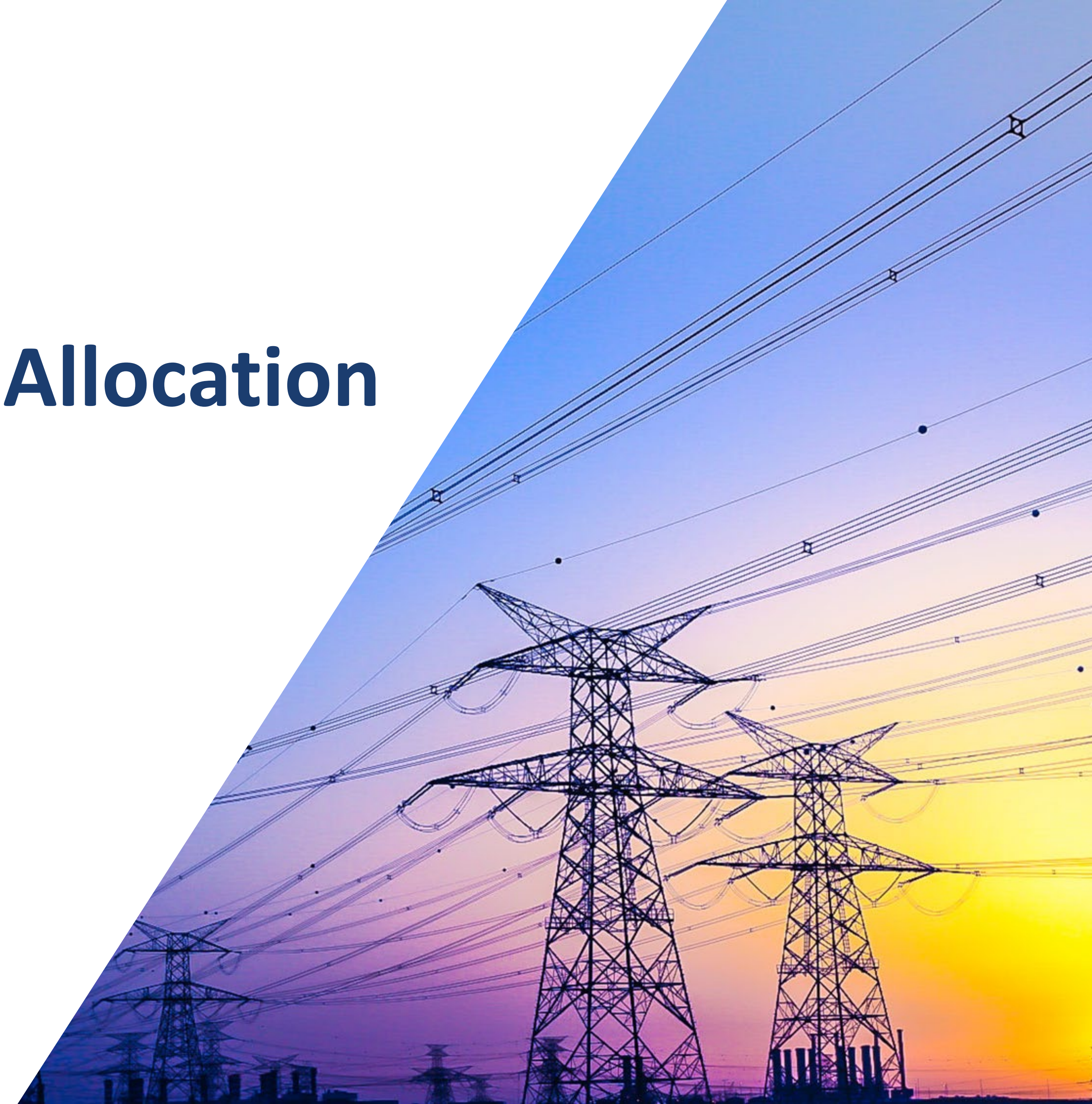
Most transmission planning efforts do not adequately account for short- and long-term risks and uncertainties affecting power markets

- **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)

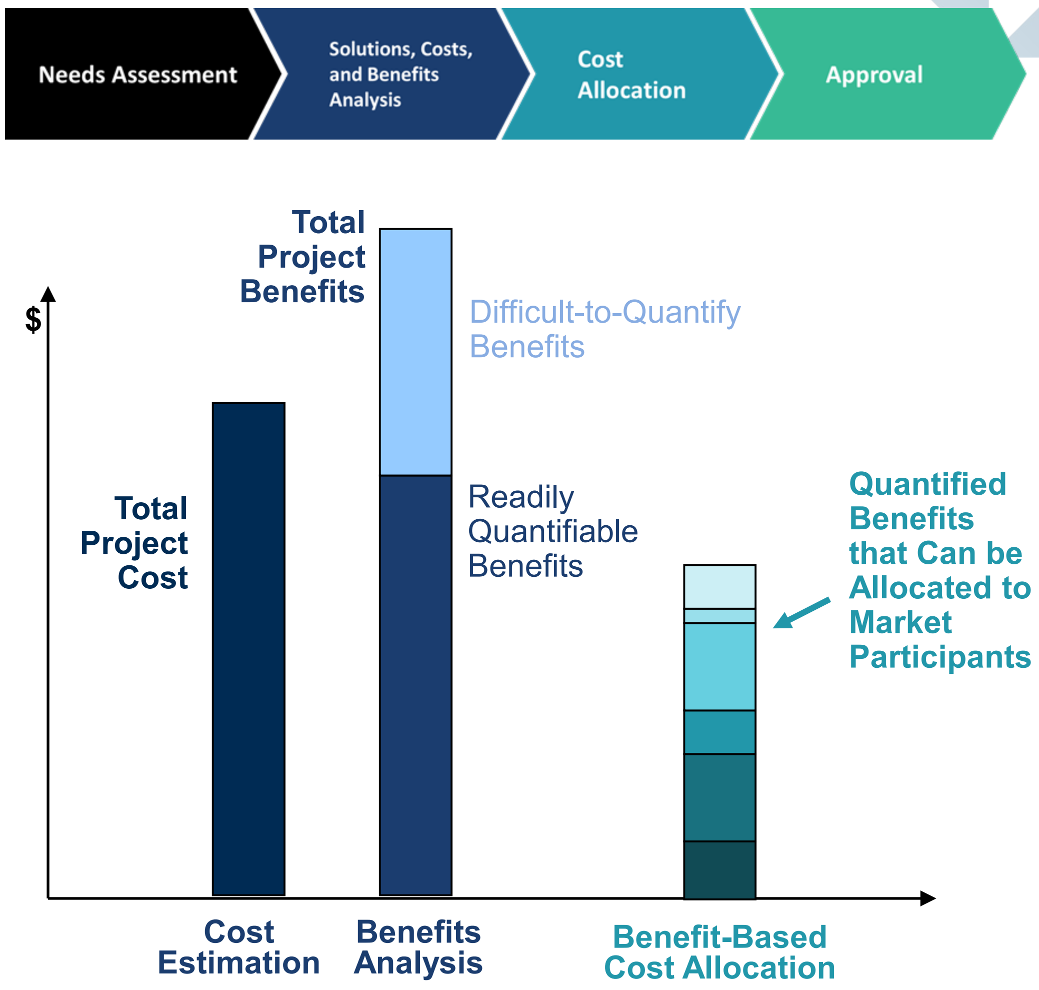
5) **Merchant Cost Recovery:** the project sponsors recover the cost of the investment outside regulated tariffs (e.g., via negotiated rates with specific customers); more common with HVDC lines

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)

Clearly Separate Benefit-Cost Analysis of Potential Projects from Cost Allocation of Approved Portfolios

Recommend 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**

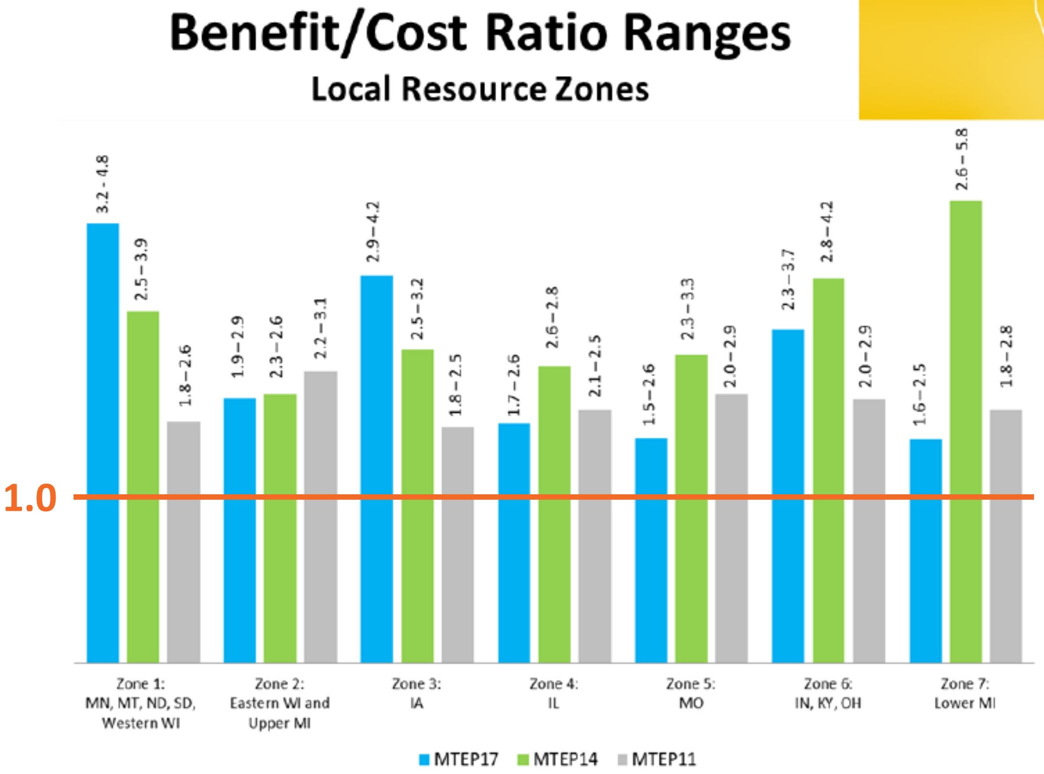
Examples of portfolio-based cost allocations:

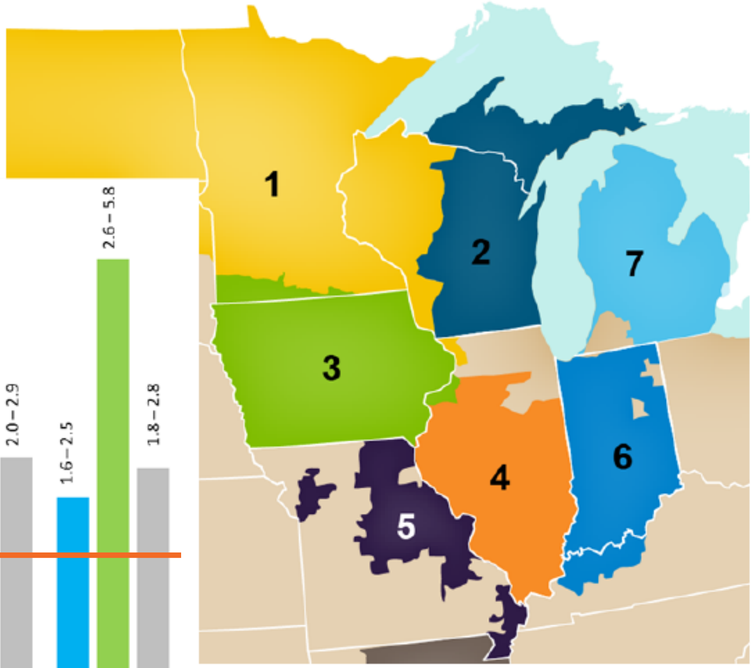
- SPP Highway-Byway (designed by RSC): Periodic review if benefits of all approved projects is roughly commensurate with costs of all projects
- MISO MVPs (with OMS input): Benefits of entire portfolio compared with allocated costs

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

Source: https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

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

Metric	RCAR I (2013$m)	RCAR II (2016$m)
APC Savings	$3,020	$8,974
Assumed Benefit of Mandated Reliability Projects	$2,475	$5,759
Mitigation of Transmission Outage Costs	$340	$1,014
Capacity Savings from Reduced On-Peak Losses	$155	$743
Increased Wheeling Through and Out Revenues	Not Monetized	$641
Marginal Energy Losses Benefits	Not Monetized	$427
Avoided or Delayed Reliability Projects	$97	$41
Benefit from Meeting Public Policy Goals	$296	$0
Reduced Cost of Extreme Events	Not Monetized	Not Monetized
Reduced Loss of Load Probability	Not Monetized	Not Monetized
Capital Savings from Reduced Minimum Required Margin	Not Monetized	Not Monetized
Total Benefits (PV of 40-yr Benefits for 2015-2054)	**$6,383**	**$17,599**
Total Portfolio Cost (PV of 40-yr ATRR)	**$4,581**	**$7,180**

Estimated 40-year Present Value of Benefit Metrics and Costs (2016 $million)

	Present Value of 40-yr Benefits for the 2015-2054 Period (2016 $million)												PV of 40-yr ATRRs (2016 $million)			
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-Peak Losses	Mitigation of Trans-mission Outage Costs	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Reduced Cost of Extreme Events	Reduced Loss of Load Probability	Capital Savings from Reduced Minimum Required Margin	Total Benefits	Before PtP and MISO Revenue Offset	PtP and MISO Revenue Offset	After PtP and MISO Revenue Offset	Benefit/Cost Ratio
AEP	$1,216	$20	$87	$207	$965	$0	$133	$59				$2,686	$1,654	$121	$1,533	1.75
CUS	-$33	$0	$0	$14	$53	$0	$5	$2				$42	$76	$5	$71	0.59
EDE	-$25	$0	$0	$24	$83	$0	$12	$0				$95	$126	$9	$117	0.81
GMO	$174	$1	$3	$38	$180	$0	$19	-$2				$412	$207	$15	$192	2.15
GRDA	$82	$0	$1	$19	$70	$0	$13	-$6				$179	$114	$8	$106	1.68
KCPL	$642	$1	$6	$76	$308	$0	$37	$51				$1,122	$407	$29	$378	2.97
LES	$115	$0	$1	$19	$64	$0	$8	$15				$223	$106	$8	$98	2.27
MIDW	$76	$0	$11	$8	$93	$0	$5	-$3				$190	$71	$5	$66	2.89
MKEC	$60	$0	$17	$13	$171	$0	$14	$30		Not Monetized		$306	$259	$20	$239	1.28
NPPD	$158	$1	$53	$58	$275	$0	$38	-$9				$574	$404	$29	$375	1.53
OGE	$1,428	$2	$65	$131	$635	$0	$66	-$64				$2,262	$838	$60	$777	2.91
OPPD	$24	$1	$3	$48	$150	$0	$23	$9				$257	$320	$23	$297	0.87
SEPC	$83	$0	$12	$9	$159	$0	$8	$11				$283	$82	$6	$76	3.73
SPS	$3,537	$12	$357	$115	$1,024	$0	$90	-$13				$5,122	$1,402	$102	$1,301	3.94
UMZ	$281	$1	$47	$96	$595	$0	$55	$191				$1,266	$397	$45	$352	3.60
WFEC	$159	$0	$77	$34	$222	$0	$20	$56				$568	$295	$21	$274	2.08
WR	$996	$1	$5	$105	$710	$0	$94	$100				$2,011	$1,002	$73	$930	2.16
TOTAL	$8,974	$41	$743	$1,014	$5,759	$0	$641	$427				$17,599	$7,760	$579	$7,180	2.45

Source: https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf

5. Summary and Recommendations

Perspective on E-RSC Principles based on Industry Experience

E-RSC Principle	Experience from other Jurisdictions
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 DFAX)
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

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

Presented By

Michael Hagerty

PRINCIPAL
WASHINGTON DC

Michael.Hagerty@brattle.com

+1.202.955.5050

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.

Presented By

John Tsoukalis

PRINCIPAL
WASHINGTON DC

John.Tsoukalis@brattle.com

+1.202.955.5050

John Tsoukalis, 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.

Additional Reading on Transmission

Pfeifenberger, Spokas, Hagerty, Tsoukalis, A Roadmap to Improved Interregional Transmission Planning, November 30, 2021.

Pfeifenberger, Transmission–The Great Enabler: Recognizing Multiple Benefits in Transmission Planning, ESIG, October 28, 2021.

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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

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