21st Century Transmission Planning:
Benefits Quantification and Cost Allocation

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PREPARED FOR

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January 2022

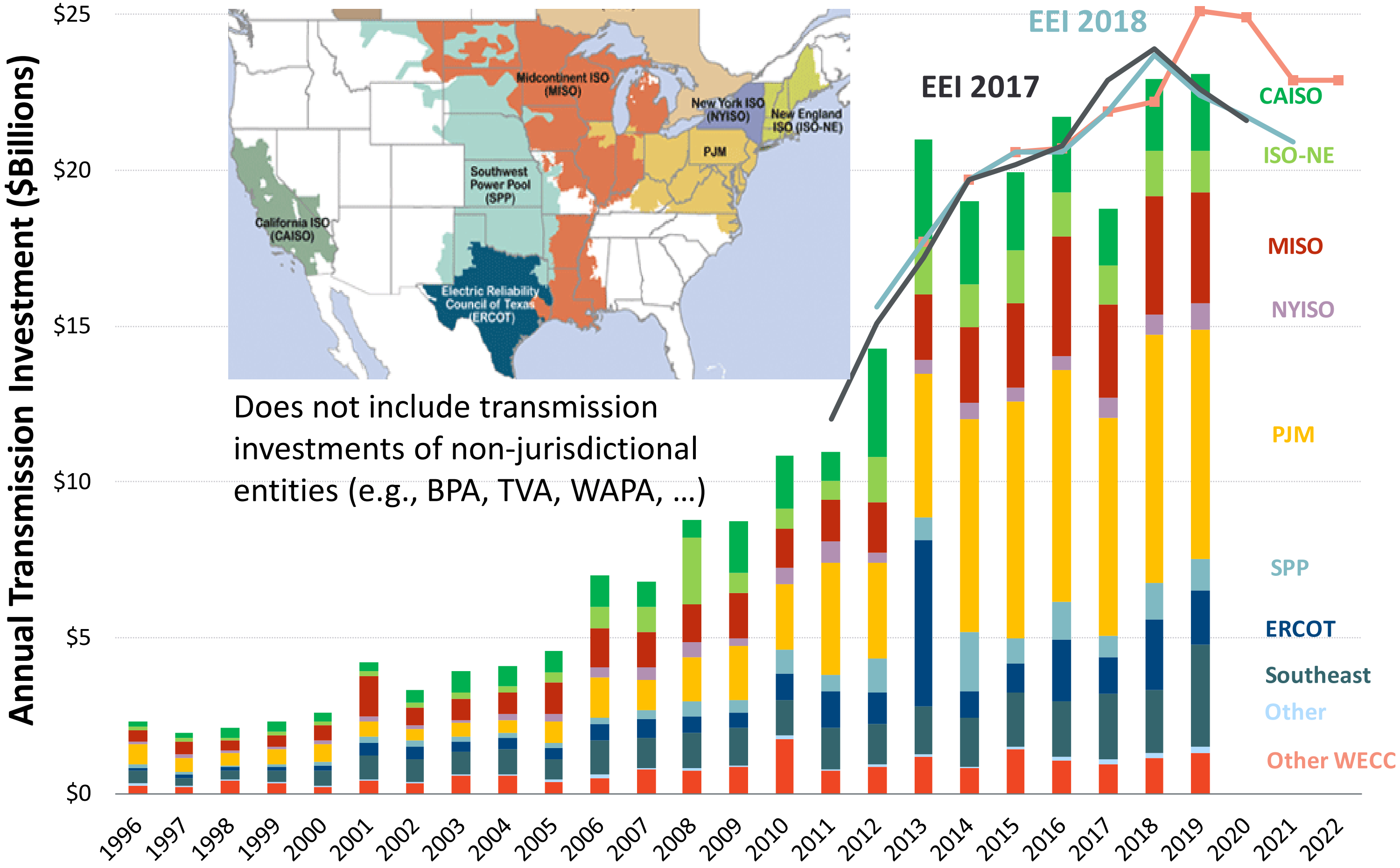
Brattle

Contents

1. The Need for Improved Transmission Planning

Transmission Investment is at Historically High Levels

Annual Transmission Investment
As reported to FERC by Region (1996 – 2019)

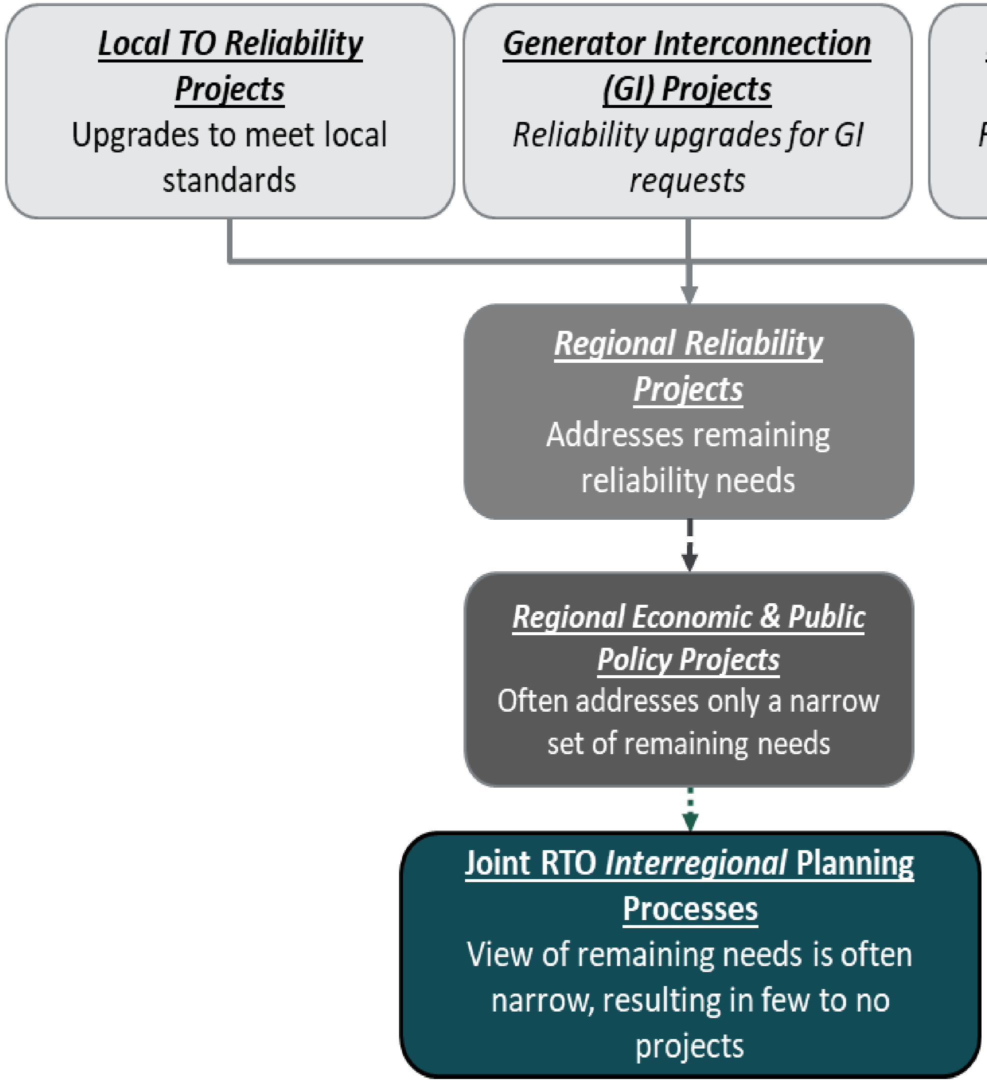


Source: FERC Form 1 Data, EEI "Historical and Projected Transmission Investment" most recent accessed here: https://www.eei.org/resourcesandmedia/Documents/Historical%20and%20Projected%20Transmission%20Investment.pdf

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

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

Current U.S. Transmission Planning Processes for…



These solely reliability-driven processes account for > 90% of all transmission investments

- None involve any assessments of economic benefits (i.e., cost savings offered by the new transmission)
- Which also means these investments are not made with the objective to find the most cost-effective solutions
- Will yield higher system-wide costs and electricity rates

Planning for economic and public-policy projects: less than 10% of all transmission investments

Interregional planning processes are large ineffective

- Essentially no major interregional transmission projects have been planned and built in the last decade

Current U.S. Transmission Planning = Higher Total Costs

Current planning processes do not yield the most valuable transmission infrastructure and result in higher overall 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 the full range of plausible futures (to explicitly account for long-term uncertainties), results in higher-cost outcomes when the future deviates from base case planning assumptions, which usually are based on "business-as-usual" or "current-trends" forecast
- Failure to consider interregional transmission solutions result in higher-cost regional and local transmission investments

The Electricity Industry is Undergoing Fundamental Changes, Which Will Require Improved Planning Processes

As many have articulated, the industry faces fundamental changes along three important dimensions (the “3Ds”), which will fundamentally change grid planning and operations

1. DECARBONIZATION

To meet state, federal, and corporate clean-energy policy objectives, output from “emitting” resources (such as coal plants) is quickly replaced by renewable resources, with rapidly falling capital costs and close-to-zero variable costs. This is fundamentally changing (a) wholesale power prices; (b) grid operations; and (c) grid planning and investments.

2. DECENTRALIZATION

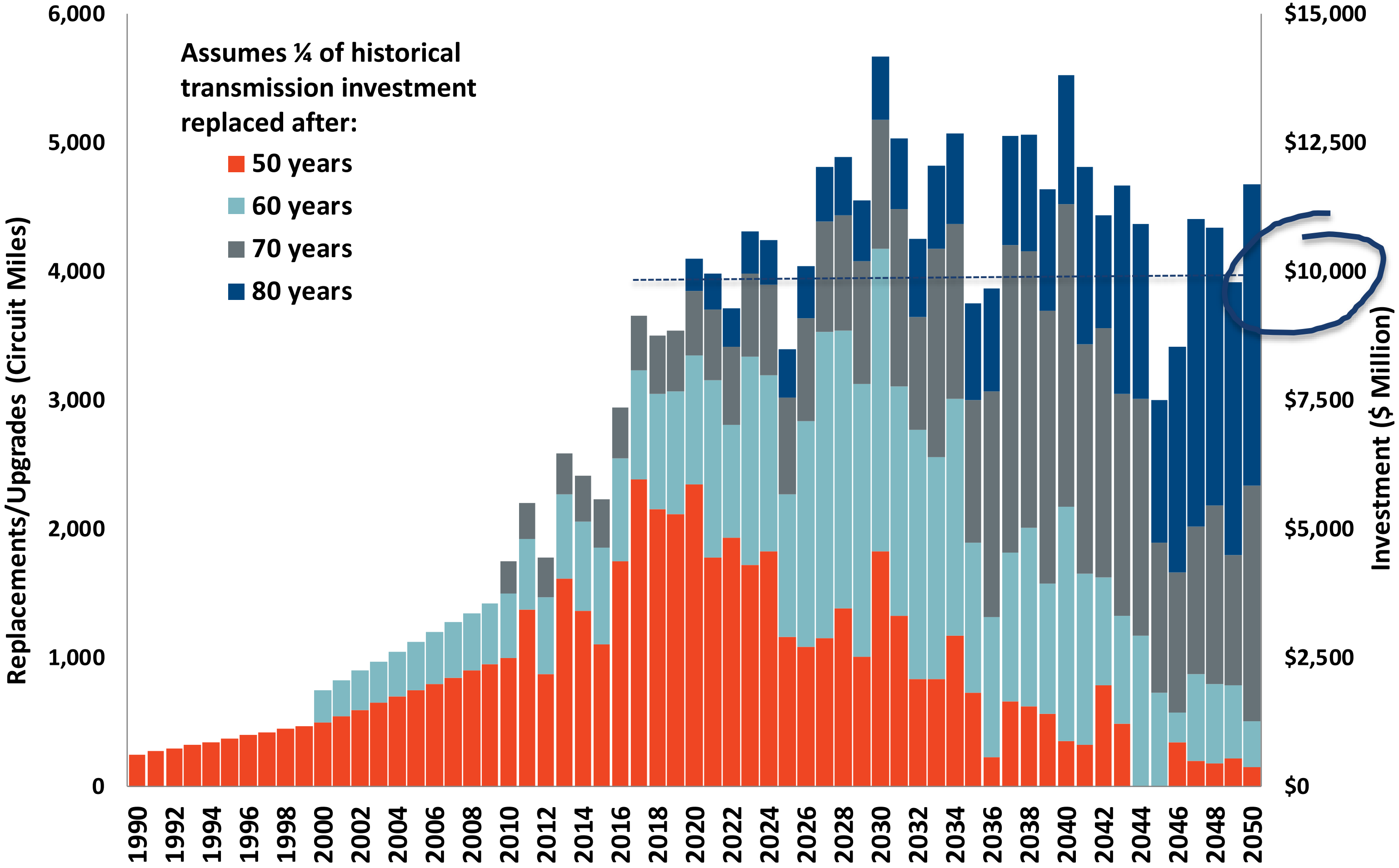
Declining costs of solar generation and batteries causes a shift away from large, central-station power plants to resources that are located on local electricity networks or “behind the meter” at homes and businesses—changing the role (but not decreasing the value) of the transmission grid.

3. DIGITALIZATION

The revolution in information and communication technologies and platforms that will continue to change nearly everything in our economy, including energy services, grid operations, and grid planning.

Challenge and Opportunity: Aging U.S. Transmission Infrastructure

- Much of today's grid was built in the 1960s and 70s
- Facilities that need to be replaced after 50 to 80 years, now likely account for $10 billion in annual transmission investment
- Might have reached 80% of total in some regions, such as PJM
- Some of these replacements are on highly-valuable right of way that could be used to "upsize" new facilities in cost-effective support of public policy goals



Source: Brattle estimate. Assumes circuit mile costs equal to those of new lines

Barriers to Regional and Interregional Transmission Planning

A. Leadership, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policy makers to prioritize interregional 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. Based on interviews with 18 organizations representing state and federal policy makers, state and federal regulators, transmission planners, transmission developers, industry groups, environmental groups, and large customers

No Time to Wait: The Need to Improve Transmission Planning Now

Efforts to improve planning processes are urgently needed 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 and 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 robust electricity grid at lower incremental costs and with more **efficient use of existing rights-of-way** for transmission

Understated benefits and disagreements over cost allocation have derailed many planning efforts and created barriers for valuable transmission projects

Proposal: Transmission Planning for the 21st Century*

Available experience already points to 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

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

Experience with Proactive & Comprehensive Planning Processes

Although still rarely used, significant experience exists with successful proactive, multi-value, scenario- and portfolio-based transmission planning efforts:

	Proactive Planning	Multi-Benefit	Scenario-Based	Portfolio-Based	Interregional Transmission
CAISO TEAM (2004)[146]	✓	✓	✓		
ATC Paddock-Rockdale (2007)[147]	✓	✓	✓		
ERCOT CREZ (2008)[148]	✓			✓	
MISO RGOS (2010)[149]	✓	✓		✓	
EIPC (2010-2013)[150]	✓		✓	✓	✓
PJM renewable integration study (2014)[151]	✓		✓	✓	
NYISO PPTPP (2019)[152]	✓	✓	✓	✓	
ERCOT LTSA (2020)[153]	✓		✓		
SPP ITP Process (2020)[154]		✓		✓	
PJM Offshore Tx Study (2021)[155]	✓		✓	✓	
MISO RIIA (2021)[156]	✓	✓	✓	✓	
Australian Examples:					
- AEMO ISP (2020)[157]	✓	✓	✓	✓	✓
- Transgrid Energy Vision (2021)[158]	✓	✓	✓	✓	✓

Source: Brattle & Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

Actual Planning Processes Used Today

Current planning processes do not (yet) take advantage of experience with proactive, multi-value, scenario- and portfolio-based transmission planning efforts

	Proactive Generation & Load	Multi-Value	Scenario-Based	Portfolio-Based[30]	Joint Interregional Planning
ISO-NE[31]	✗	✗	✗	✓	✗
NYISO[32,33]	✗	✗	✗	✗	✗
– PPTPP only	✓	✓	✓	✓	✗
PJM[34,35]	✗	✗	✗	✗	✗
Florida	✗	✗	✗	✗	✗
Southeastern Regional	✗	✗	✗	✗	✗
South Carolina Regional	✗	✗	✗	✗	✗
MISO (excl. MVP, RIIA)[36]	✗	✗	✗	✗	✗
SPP (ITP)[37,38]	✗	✓	✗	✓	✗
CAISO[39,40]	✓	✗	✓	✗	✓
– TEAM only	✓	✓	✓	✓	✓
WestConnect	✗	✗	✗	✗	✗
NorthernGrid[41]	✗	✗	✗	✗	✗

Source: Brattle & Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

2. Quantifying Transmission Benefits

Understanding Transmission-Related Benefits

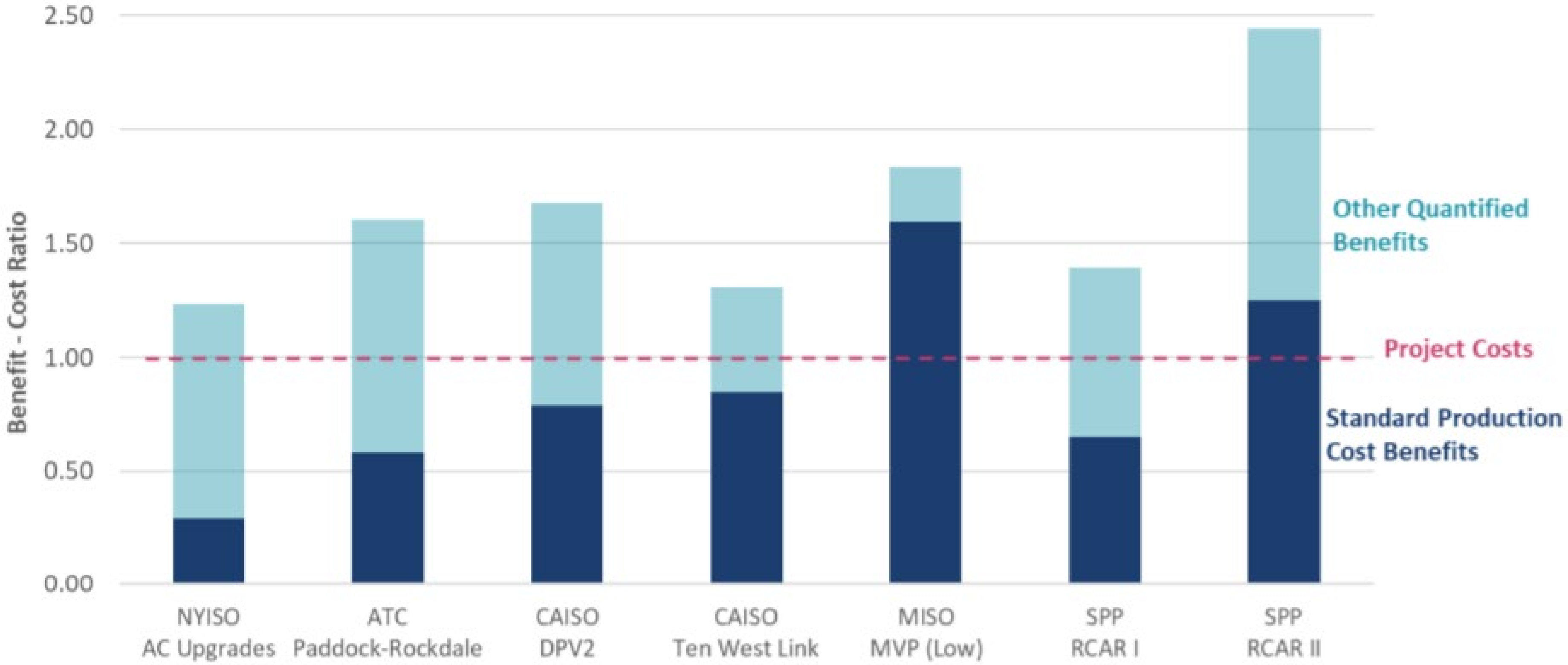
The wide-spread nature of transmission benefits creates challenges in estimating benefits and how they accrue to different users, which also complicates cost allocation

▪ **Broad in scope, providing many <u>different types</u> 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
▪ **<u>Wide-spread</u> geographically**	• Multiple transmissions service areas • **<u>Multiple states</u>** or regions
▪ **<u>Diverse</u> in their effects on market participants**	• **<u>Customers</u>**, **<u>generators</u>**, **<u>transmission owners</u>** 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 on solely on traditionally-quantified <u>Adjusted Production Cost</u> (APC) Savings results in the rejection of beneficial transmission projects:

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)]

We have a Decade of 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

Brattle Group Reports on Transmission Benefit-Cost Analyses Summarize Much of the Available Experience

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

Link: https://bit.ly/3dnKrxe

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

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April 2015

Link: https://bit.ly/2GU4h7w

The Brattle Group

Link: https://bit.ly/3jS0PsB

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

July 2013

Judy W. Chang

Johannes P. Pfeifenberger

J. Michael Hagerty

Link: https://bit.ly/2KaFLAk

BU

Boston University Institute for Sustainable Energy

The Value of Diversifying Uncertain Renewable Generation through the Transmission System

September • 2020

Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

Link: Brattle Grid Strategies

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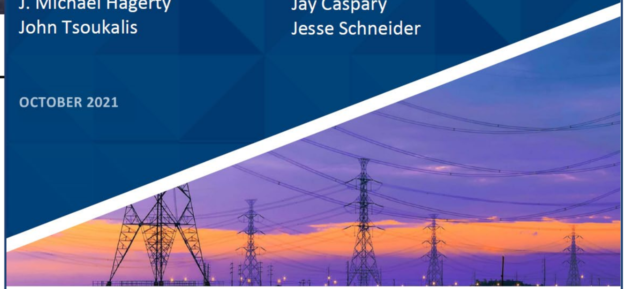

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Summarizes proven approaches to quantifying various benefits

“Checklist” of Transmission Benefits With Proven Practices for Quantifying Them

As we have documented in our recent report (filed with ANOPR comments) available proven practices:

1. Consider for each project (or synergistic portfolio of projects) the full set of benefits transmission can provide (*see* table)
2. Identify the benefits that plausibly exist and may be significant for that particular project or portfolio; then
3. Focus on quantifying those benefits

(See our recent report with Grid Strategies for a summary of quantification practices)

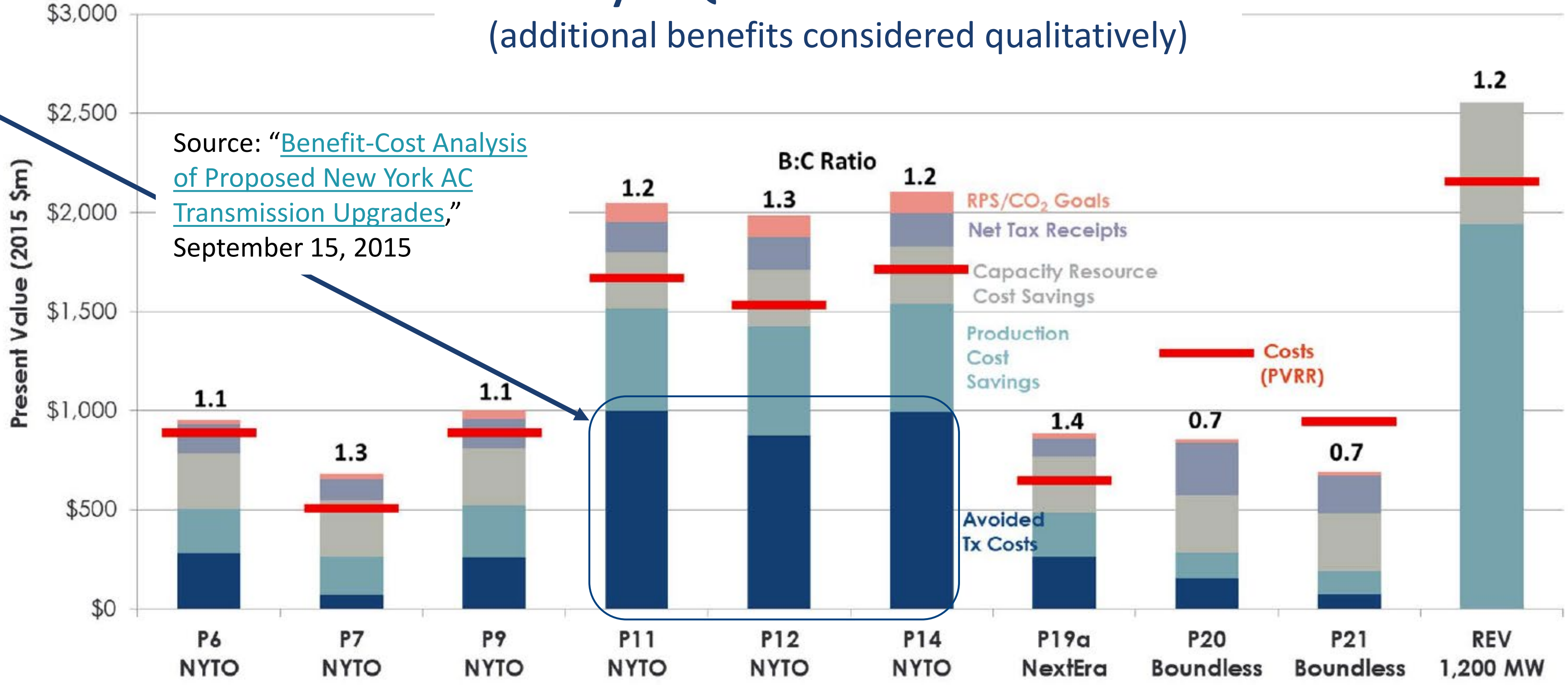
Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic “Day 1” market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

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

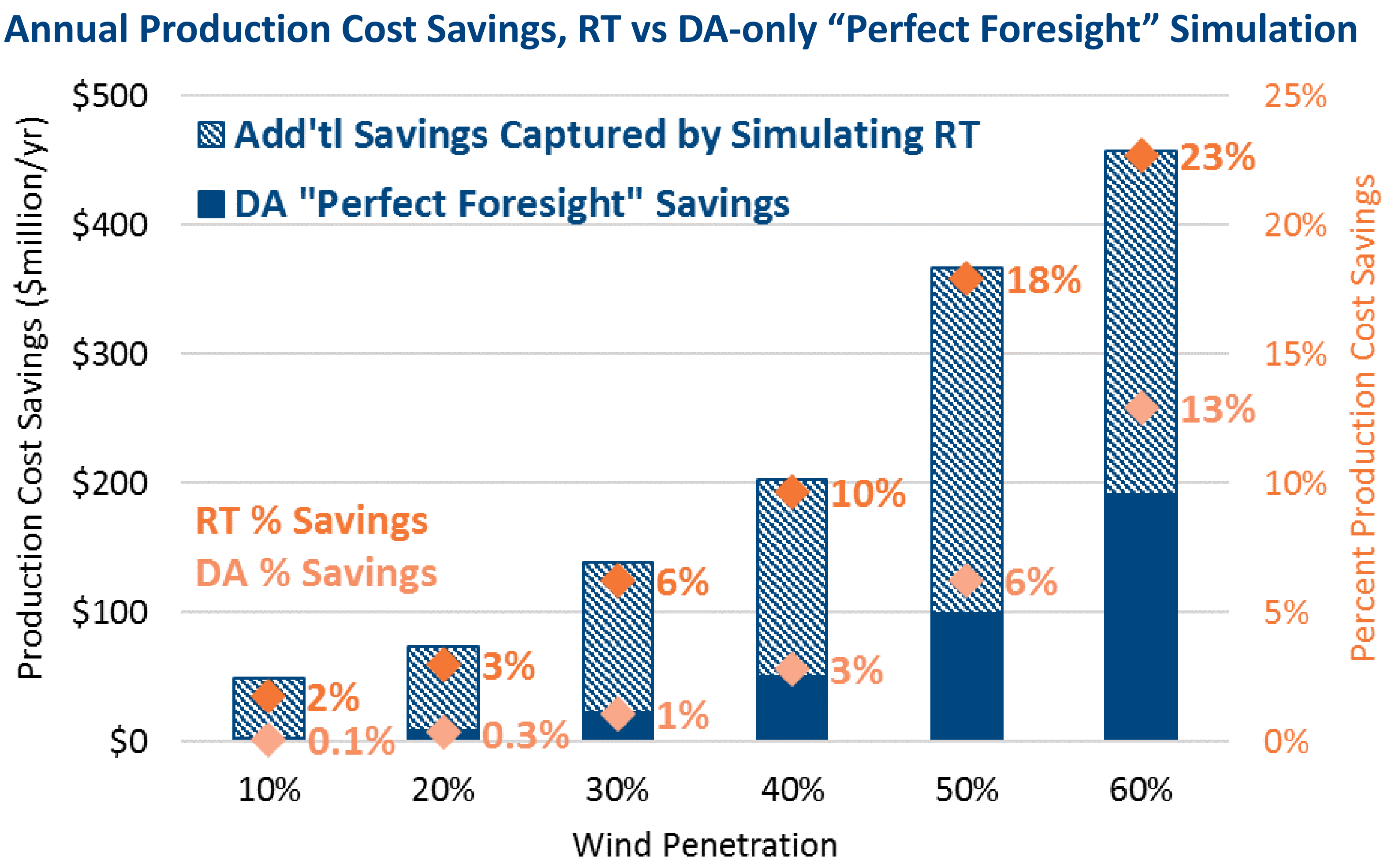
Avoided cost of future replacement of aging transmission infrastructure and future reliability projects cover up to half of some of the public policy projects' costs

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



Source: "[Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades](#)," September 15, 2015

Simulating Uncertainty → Higher, More Accurate Benefits



Key takeaways

- Quantified transmission benefits can be significantly understated using the prevailing “Perfect Foresight” simulation approach:
  - **RT = 10x DA at 20% renewables**
  - **RT = 3x DA at 50% renewables**
- The higher benefit means optimal tradeoff shifts more from building local renewables to building more regional and interregional transmission to cost-effectively meet policy goals

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

Risk Mitigation Through Transmission Investments

Additional considerations regarding the risk mitigation and insurance value of transmission infrastructure:

- Given that it can take a decade to develop new transmission, delaying investment can easily **limit future options** and result in a **higher-cost, higher-risk** overall outcomes
  - “Wait and see” approaches limit options, so can be costly in the long term
  - The industry needs to plan for both short- and long-term uncertainties more proactively – and develop "anticipatory planning" processes
- **“Least regrets” planning** too often only focuses on identifying those projects that are <u>beneficial under most circumstances</u> without considering the risk of not building transmission
  - Need to focus not only on (1) the regret that the cost of the projects may exceed benefits; but also (2) the risk of very high cost outcome if transmission is not built (cost of not having insurance when it is needed)
  - Yet, most current “least regrets” planning efforts do not consider the many potentially “regrettable circumstances” where the failure to expand transmission could result in very high-cost outcomes
- **Probabilistic weighting assumes risk neutrality** and does not distinguish between investment options with very different risk distributions

Scenario Analysis Example: ATC's Paddock-Rockdale Project

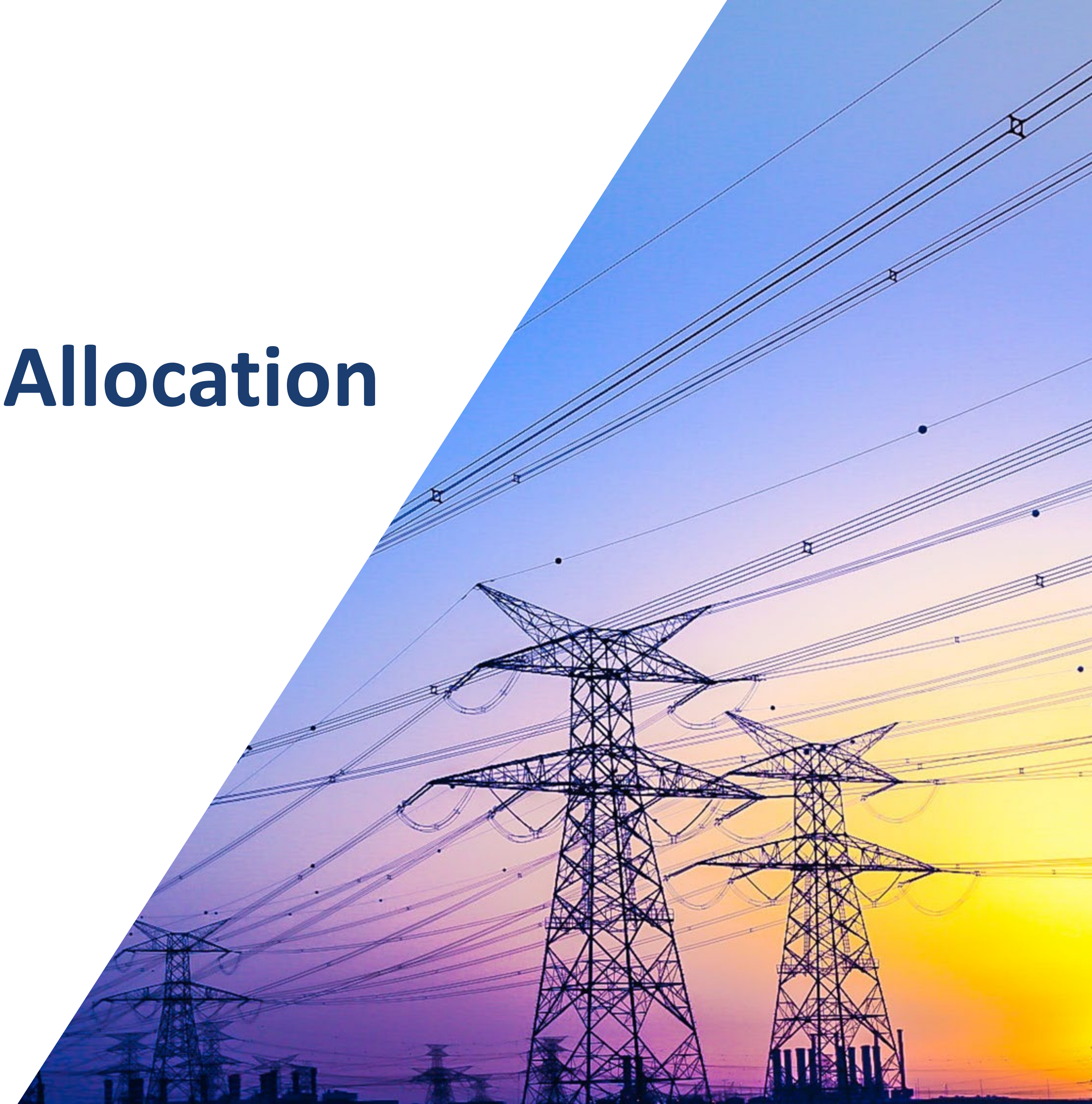
In evaluating the Paddock-Rockdale Project, ATC evaluated seven plausible futures, spanning the range of long-term uncertainties.

- The 40-year PV of customer benefits fell short of the $136 million PV of the project's revenue requirement in the "Slow Growth" future, but exceeded the costs in all other futures
- The net benefits in the other six futures ranged from:
  - $100 million (above cost) under the "High Environmental" future
  - to approx. $400 million under the "Robust Economy" and "High Wisconsin Growth" futures
  - reaching up to approx. $700 million under the "Fuel Supply Disruption" and "High Plant Retirements" futures

The analyses of multiple scenarios of plausible futures show:

- The estimated benefits can range widely across sets of plausible futures
- The project is beneficial in most (but not all) futures
- Not investing in the $136 million project can leave customers up to $700 million worse off in two of seven plausible futures

3. Transmission Cost Allocation



Disagreements on Cost-Allocation Creates Barriers Even for Clearly-Beneficial Projects

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

Harder: regionally share costs of transmission "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: share costs of projects that provide broad regional economic or public-policy benefits:

- 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 create disagreements and are often ignored
- Large regional projects for environmental policies pit states that have them (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

Almost Impossible: cost allocation for interregional projects; but mostly hypothetical because no significant interregional projects have been planned in the last decade

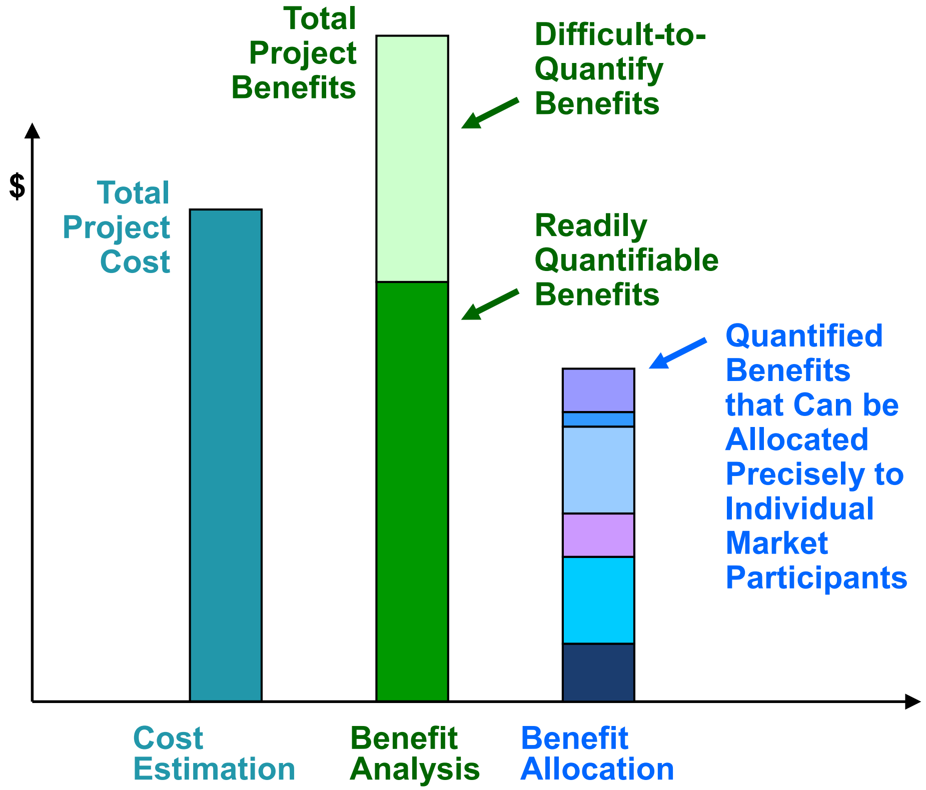
Basic Cost Allocation and Recovery Mechanisms

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:** transmission costs are recovered uniformly from all loads in a defined market area
   - RTO-wide examples: ERCOT, >200kV in CAISO, >115kV in ISO-NE, MVPs in MISO
   - Highway/Byway in SPP: postage stamp for all ITP projects >300 kV; 1/3 postage stamp and 2/3 license plate for projects 100-300 kV; 100% license plate for projects below 100 kV
   - Often implemented by first allocated project costs uniformly to TOs (e.g., on a MW or MWh load ratio share), who then recover these allocated costs in their License Plate tariffs.
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); largely possible only with HVDC 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 (e.g., CAPX 2020; often used in WECC)

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

Recommend 2-step approach:

1. Determine whether projects are beneficial overall, quantifying a broad set of benefits
   - Without quantifying most benefits, many desirable projects (or synergistic portfolios) 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 broad portfolio of beneficial projects should be allocated 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



Cost Allocation: 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 <u>portfolio of projects</u> 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 <u>vs.</u> many analyses for many projects**

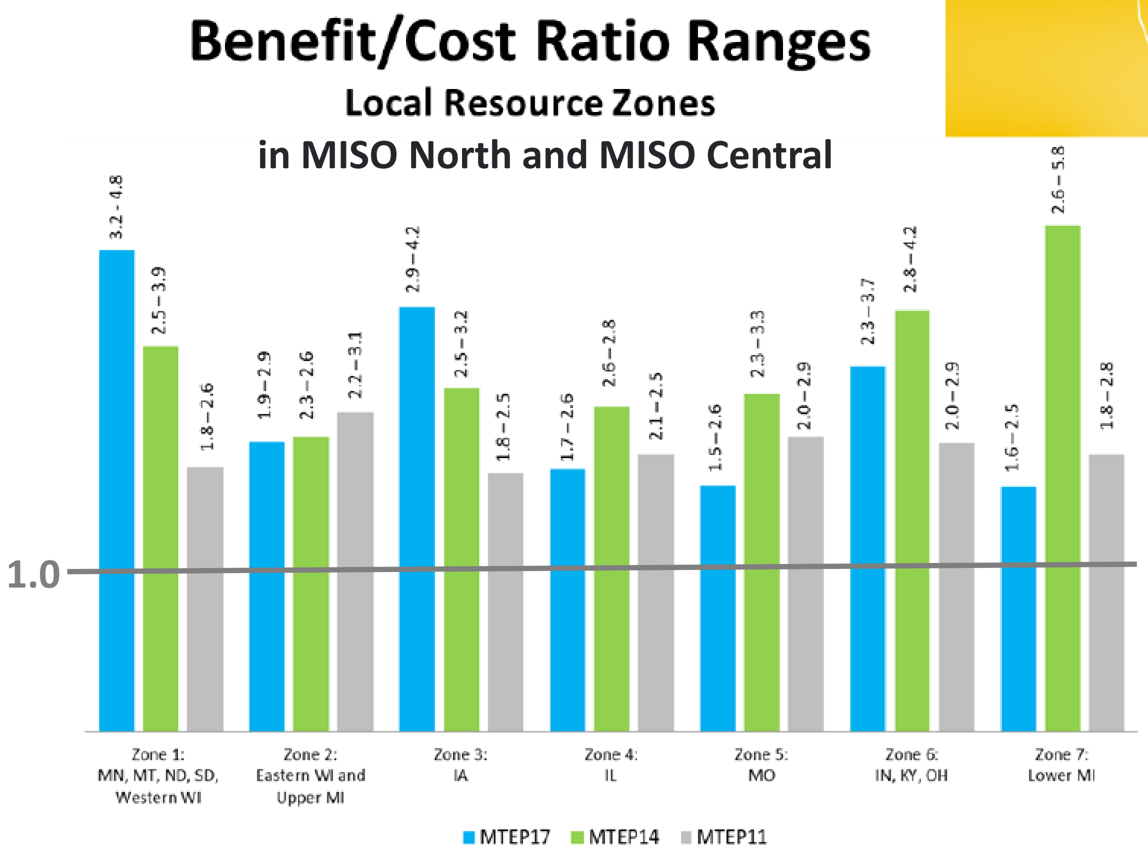
Examples of portfolio-based cost allocations:

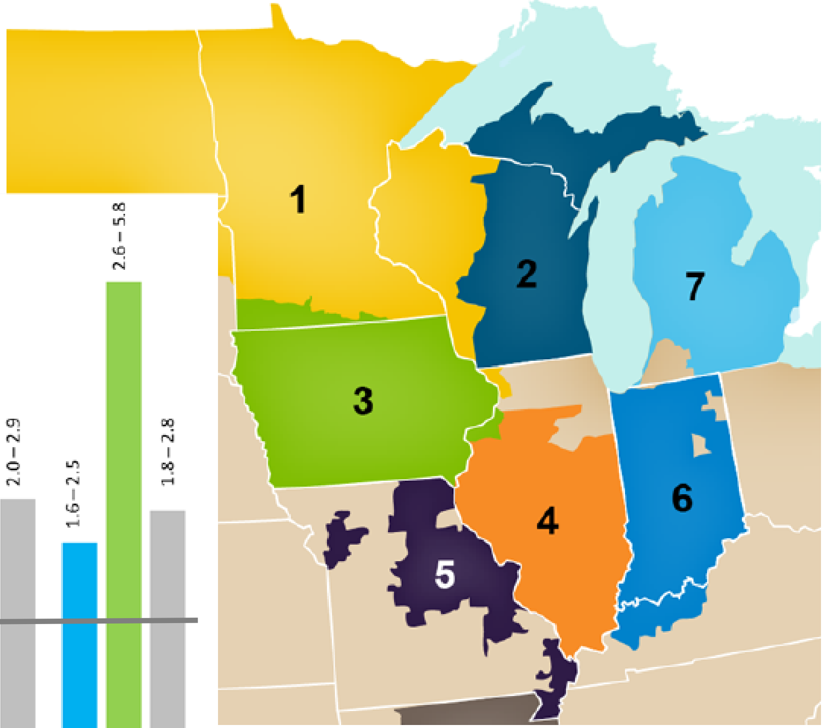
- <u>SPP Highway-Byway</u> (designed by RSC): Periodic review if benefits of all approved projects is roughly commensurate with costs of all projects
- <u>MISO MVPs</u> (with OMS input): Benefits of entire portfolio compared with allocated costs

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

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

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

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

4. Interregional Planning

National Studies Show Large Benefit of Interregional Transmission

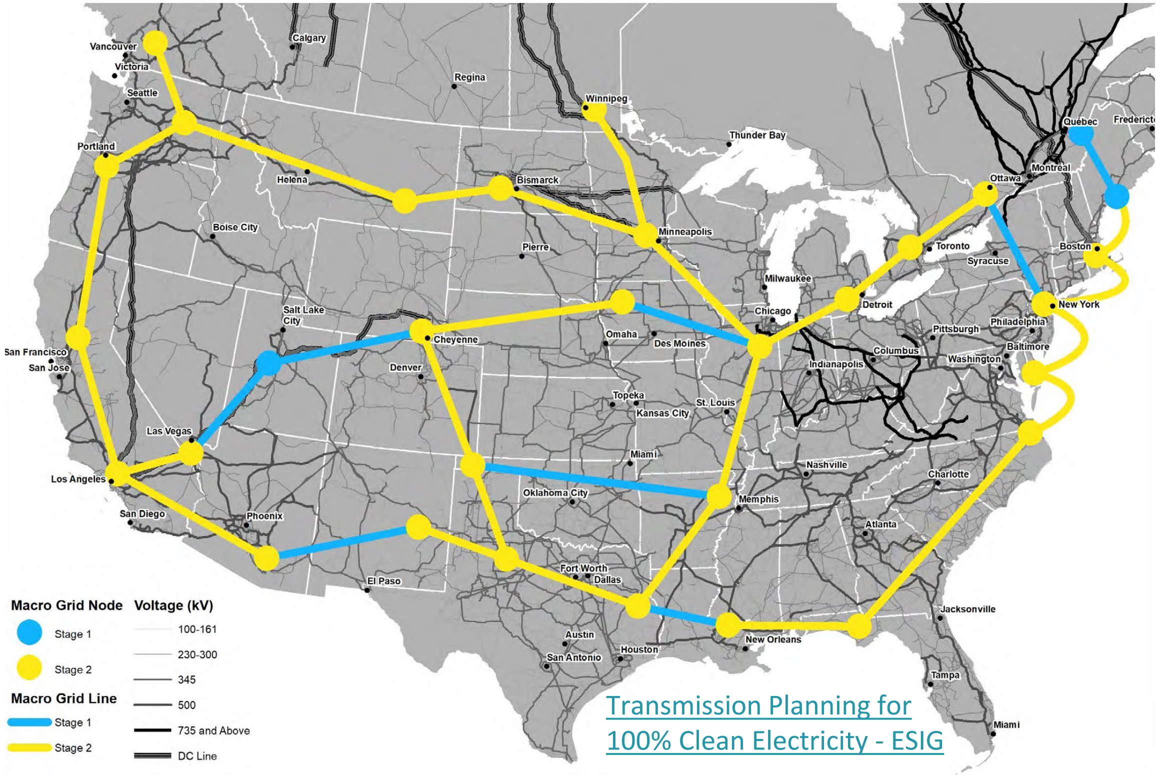
Study	Region	Findings
NREL North American Renewable Integration Study (2021)	U.S., Canada, Mexico	• Increasing trade between countries can provide $10-30 billion in net benefits • **Interregional transmission expansion achieves up to $180 billion in net benefits**
MIT Value of Interregional Coordination (2021)	Nation-Wide	• National coordination of **reduces the cost of decarbonizing by almost 50% compared to no coordination between states** • The lowest-cost scenario builds almost 400 TW-km of transmission; including **roughly 100 TW-km of DC capacity between the interconnections** and over 200 TW-km of interregional AC capacity • **No individual state is better off implementing decarbonization alone** compared to national coordination of generation and transmission investment • Low storage and solar costs still result in significant cost effective interregional transmission
Princeton Net Zero America Study (2021)	Nation-Wide	• Achieving net-zero emissions by 2050 requires **700-1,400 TW-km of new transmission** • Investment in transmission needed ranges **$2-4 trillion dollars by 2050**
U.C. Berkeley 90% by 2035 (2020)	Nation-Wide	• The only national study that suggest relatively little interregional transmission would be needed to achieve 90% clean electricity. However, the study's simulation approach does not utilize more granular and well-established methods to properly value interregional transmission.
Vibrant Clean Energy Interconnection Study (2020)	Eastern Interconnect	• **40 to 90 TW-km of transmission is built by 2050** to meet climate goals • Transmission development can create **1-2 million jobs in the coming decades**, more than wind, storage, or distributed solar development • Transmission **reduces electricity bills by $60-90 per MWh**
Wind Energy Foundation Study (2018)	ERCOT, MISO, PJM, and SPP	• Transmission planners are not incorporating this rising tide of voluntary corporate renewable energy demand into plans to build new transmission
NREL Seams Study (2017)	Eastern and Western Interconnects	• Major new ties between interconnections **saves $4.5-$29 billion** over a 35 year period

Source: A Roadmap to Improved Interregional Transmission Planning, November 30, 2021.

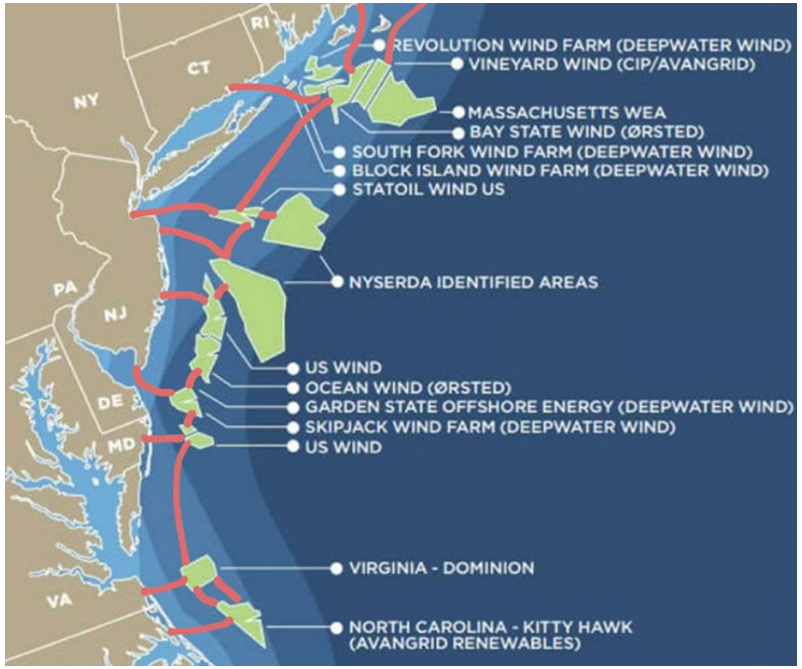
Long-term: Will regions be integrated into a more geographically-diverse national grid?

As state and regional shares of renewable generation (including offshore wind) increase, a robust interregional grid will become more important to ensuring reliability and cost effectiveness

- The geographic scale of the grid needs to (1) **reach well beyond the size of large weather systems**; and (2) integrate a **more diverse mix of resources** (wind, solar, hydro, …)
- Local storage and distributed resources will help, but not eliminate the need for broad geographic diversification of uncertain intermittent generation beyond size of large weather systems

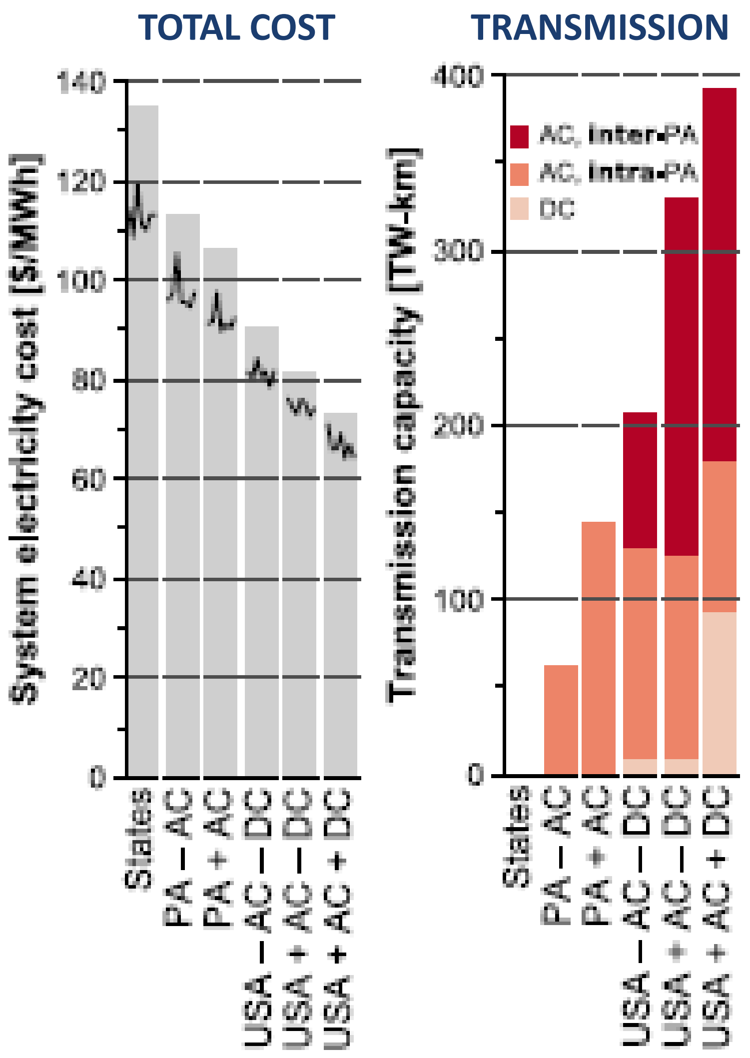


[Transmission Planning for 100% Clean Electricity - ESIG]



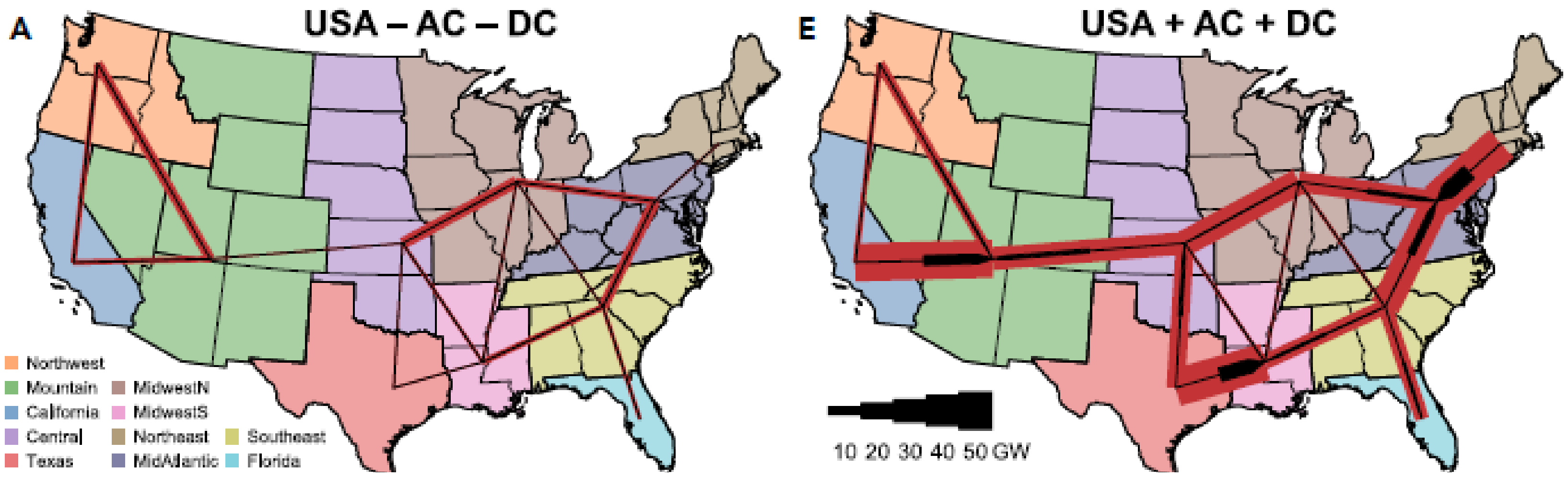
https://rtoinsider.com/rto/grid-planners-renewable-future-199014/

Example: MIT Value of Interregional Coordination (2021)



Key Result: A more robust national grid would reduce the total cost of decarbonizing the grid … but (higher-cost) regional and more local solutions may also be feasible

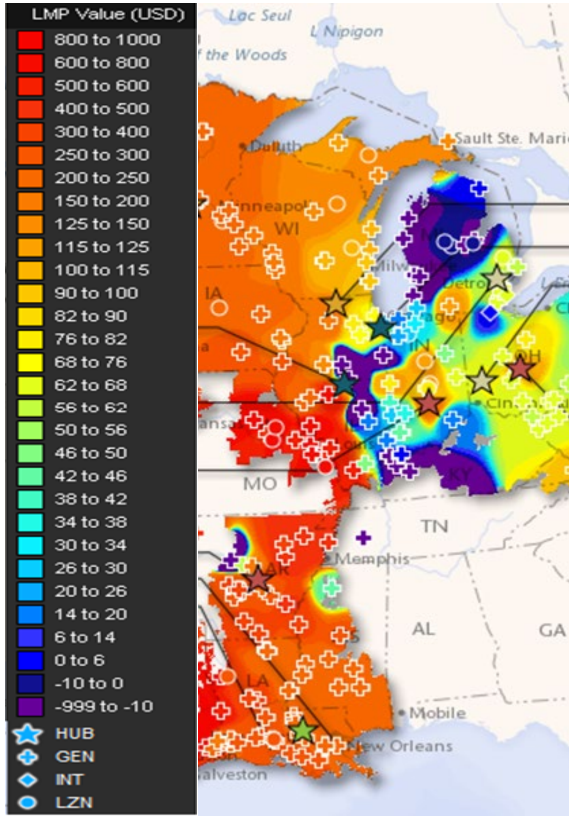
Optimal Transmission Build: With and Without National Transmission Coordination



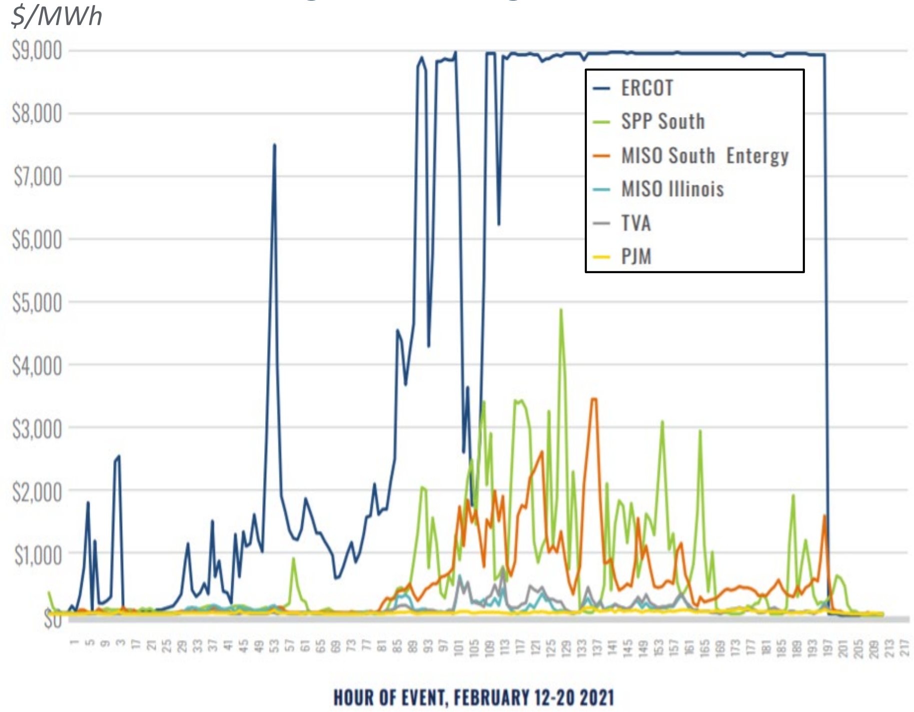
Case Study on Interregional Tx Benefits: Winter Storm Uri

Transmission constraints led to substantial price separations. Anadditional GW of transmission into Texas would have fully paid for itself over the course of the four-day event ([Goggin, 2021]).

LMPs on Feb 15th, 2021 at 7:45-7:55



Electricity Price Differences Between Regions During Uri



Savings per GW of Additional Interregional Transmission Capability
($ millions)

ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82

Limitations of National Studies Showing Interregional Benefits

Although existing studies demonstrate the benefits of interregional transmission, they have not been successful in motivating improved interregional planning or actual transmission project developments. The reasons include:

- Many studies **tend to analyze aspirational clean energy targets (e.g., 90% by 2035 or 100% by 2050)** not the actual policies and mandates applicable for the next 10-15 years
  - By not modeling actual state or federal policies, clean-energy mandates, and renewable technology preferences, the studies cannot demonstrate a compelling "need" to policy makers, regulators, and permitting agencies
- The studies are **not transmission planning studies** that produce specific transmission projects that can be developed to deliver the identified benefits and they do not support a need for specific projects
  - The results of these studies do not connect with RTO planning processes and needs identification,
  - The studies typically do not consider how to recover ("allocate") transmission costs
- Studies **fail to identify how benefits and costs are distributed** across utility service areas, states, or RTO/ISO under different scenarios, as would be necessary to gain support and develop feasible cost recovery options
- There has not been **an analysis of the state-by-state economic impact and job creation** from interregional transmission development, reduced electricity prices, and shifts in the locations of clean-energy investment
- Most studies do not **propose actionable solutions** to address the many barriers to planning processes and to the development of new interregional transmission projects

National Studies are Not a Substitute for Transmission Planning

While national studies indicate the economic benefits of new regional and interregional transmission, they do not analyze the transmission grid in sufficient detail to yield actionable interregional transmission plans (and cannot substitute for interregional transmission planning)

- Various "macro grid" studies show how much transmission capacity might be cost effective between certain regions, but they fail to:
  - Consider existing **transmission planning criteria** (e.g., reliability, stability, size of largest contingencies)
  - Pinpoint **specific locations on the power system** where transmission projects could interconnect to achieve cost reductions (studies typically only indicate which regions would benefit from more transfer capacity)
  - **Identify a list of actionable individual transmission projects (or manageable portfolios of projects)** and quantify project-specific benefits needed by regional planning authorities and transmission developers to obtain approvals for individual projects
  - **"Connect" to RTO/ISO and TO planning processes** that can approve actual projects for development
  - **Consider actual project costs and cost allocations** (including the costs of necessary local upgrades)

Detailed interregional transmission studies that include RTOs/ISOs are needed to identify specific projects that meet all planning criteria and are cost-effective overall and to the individual regions

Challenges Faced in Developing Interregional Transmission

Large inter-regional transmission projects are extremely difficult to plan, as values are poorly understood and no mechanism for cost recovery exists

- Inter-regional planning is a voluntary and ad-hoc process
- Reliability needs (the main driver of regional planning) rarely apply to interregional projects and economic benefits of interregional transmission are not well understood, rarely quantified, or inconsistently analyzed by regions
- Cost recovery (cost allocation) highly contentious and not specified for interregional projects

Unlike transmission planning for vertically-integrated utilities and some regional planning efforts, inter-regional transmission planning is not coordinated with long-term generation planning

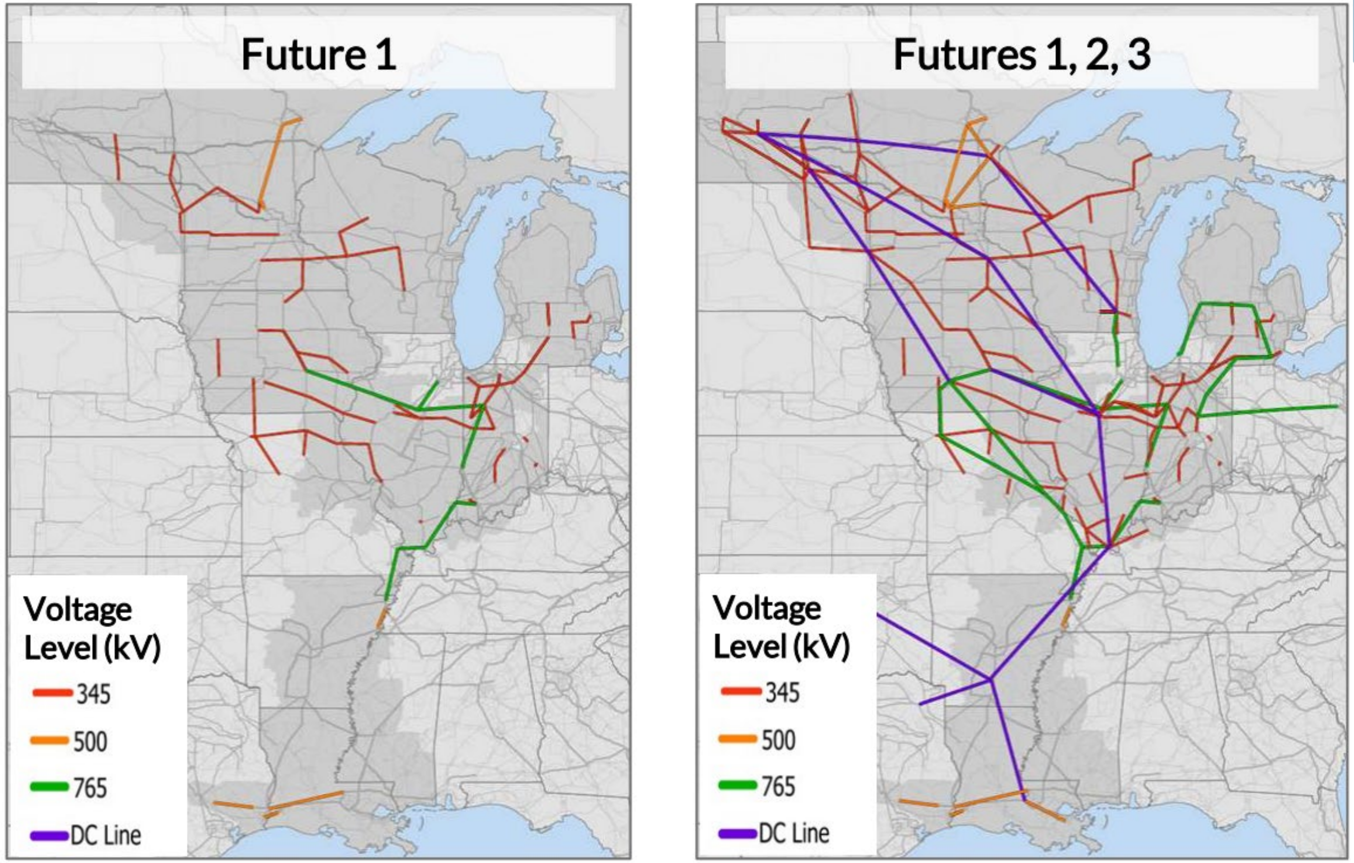
- Long-term transmission and generation planning tend to be disconnected, both in process and in analytical approach
- Many inter-regional renewable integration studies focus on renewable generation investments, but tend to use generic public-policy and transmission assumptions with limited credibility, not reflecting regional and state-level differences

Regional planning will tend to pre-empt more valuable and cost effective interregional solutions

Example: MISO RIIA Study

- MISO's new Renewable Integration Impact Assessment (RIIA) improves on many other planning studies by:
  - Establishing the need to study both <u>policy</u> goals and <u>reliability</u> goals simultaneously
  - Considering diverse future <u>scenarios</u>
- However, the study does not address any interregional opportunities:
  - Despite modeling five regions in addition to MISO, the study mostly did not consider interregional transmission (see figures)
  - Recommends a "least-regret" transmission plan, which is not the "optimal" transmission plan (and does not address possibility of regret from inadequate T)
- Even if "optimal" for MISO, it's likely far from optimal for the broader grid

MISO's projected scope of transmission expansion needs



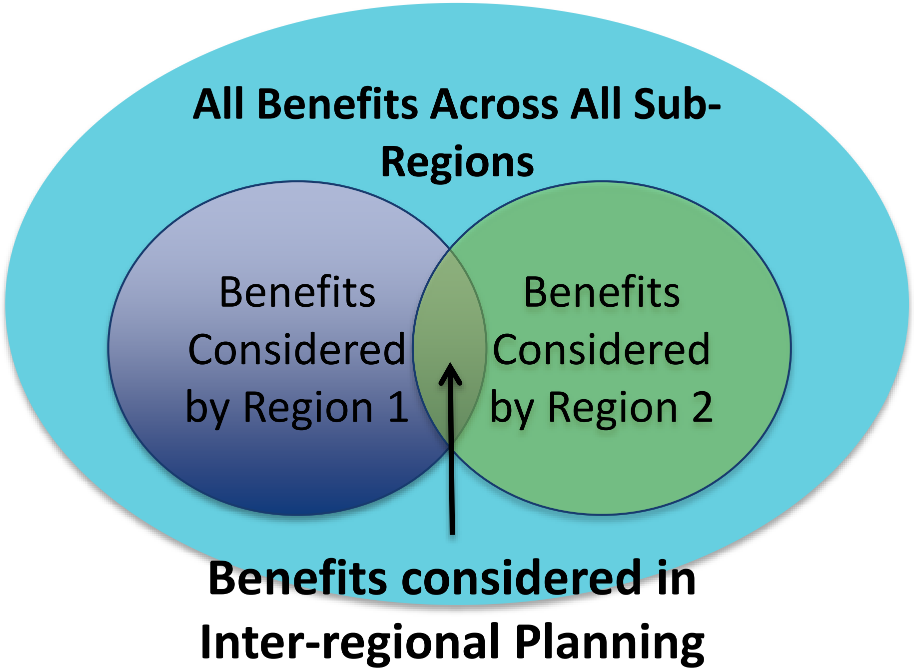
Source: MISO LRTP Roadmap March 2021

How would SPP-MISO-PJM wide planning results differ?

Example of Interregional Planning Barrier: Understated Transmission Benefits

Divergent criteria result in “least-common-denominator” planning approaches create significant barriers for transmission between regions

- Experience in the parts of the U.S. shows that very few (if any) inter-regional projects will be found to be cost effective under this approach
- Multiple threshold tests create additional inter-regional hurdles



Planning processes currently use “least common denominator” approach and do not evaluate interregional projects based on their combined benefits across all regions

Recent proposal to only utilize each region’s benefits framework will be helpful, but insufficient

Example of Interregional Planning Barrier: "Compartmentalized" Benefits

Experience from the Eastern regions shows that most planning processes compartmentalize needs into "reliability," "market efficiency," "public policy," and "multi-value" projects – which in turn fails to identify valuable projects.

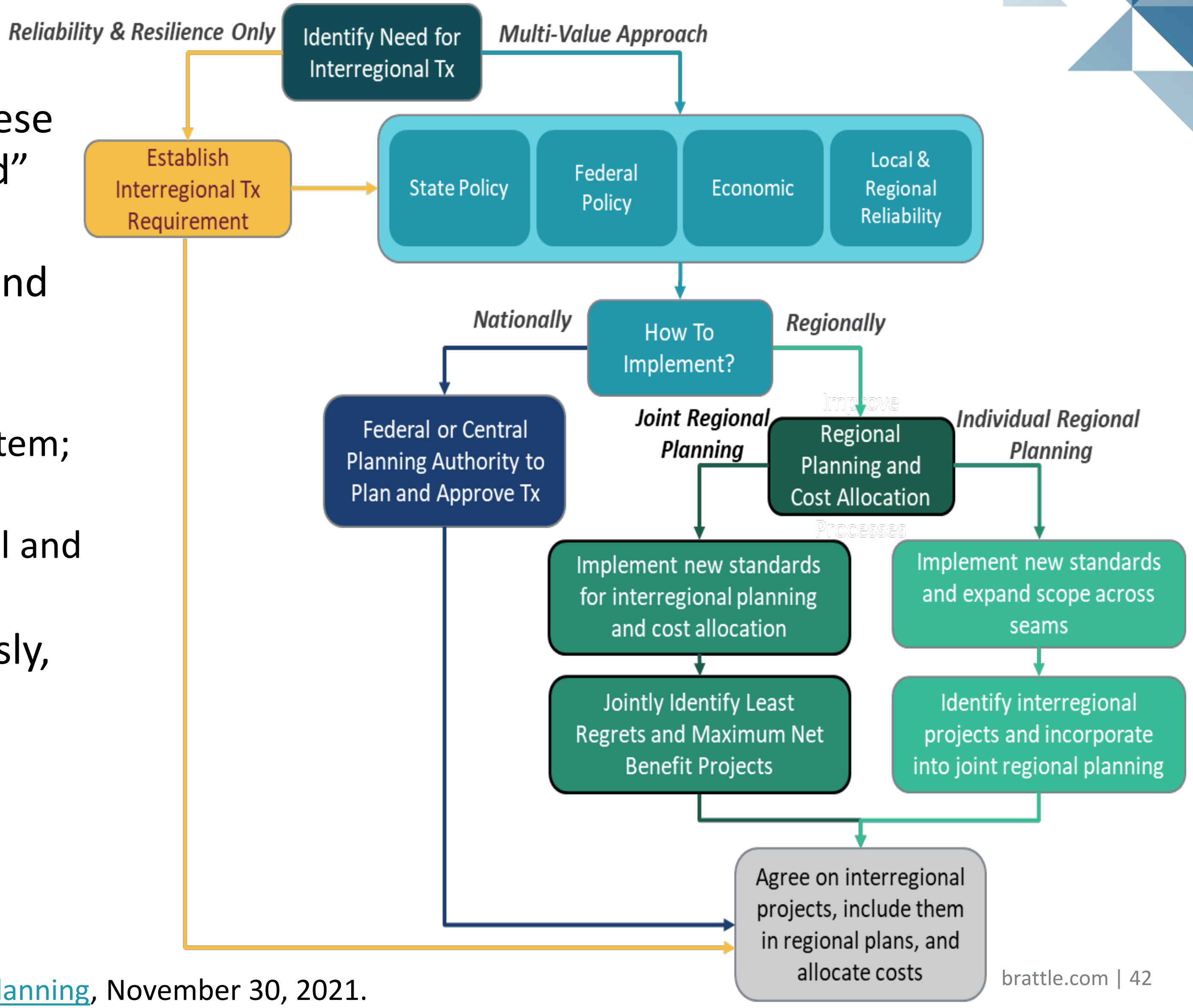
Projects Considered in MISO-PJM Planning:
(as Ordered by FERC)

Project Type in RTO-1 \ Project Type in RTO-2	Reliability	Market Efficiency	Public Policy	Multi-Value
Reliability	Yes	no	no	no
Market Efficiency	no	Yes	no	no
Public Policy	no	no	Yes	no
Multi Value	no	no	no	no

- Compartmentalizing creates additional barriers at the inter-regional level by limiting projects to be of the same type in neighboring regions (see MISO-PJM example).
- It eliminates many projects from consideration simply because they don't fit into the existing planning "buckets."

Options for Improving Interregional Planning Processes

- While national studies show there are benefits of interregional transmission, these studies do not create an actionable “need” for approving projects
- Multiple paths to establish the need for and planning of interregional transmission projects based on:
  - the value they provide to the electricity system; and
  - planning process implementation by federal and regional planning authorities
- These paths can be pursued simultaneously, identifying transmission needs through:
  - **New Interregional Tx requirements?**
  - **New Federal planning?**
  - **Improved joint RTO planning**
  - **Expanded planning by individual RTOs**



Source: A Roadmap to Improved Interregional Transmission Planning, November 30, 2021.

5. Summary and Recommendations

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

Summary and Recommendations

Focus less on addressing near-term reliability and local needs, but proactively 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

Improve benefit-cost analyses and cost allocations to offer more cost-effective and less controversial outcomes:

- More fully consider broad range of reliability, economic, and public-policy benefits, including experience gained though:
  - 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

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Hannes specializes in wholesale power markets and transmission. He 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, industry groups, and regulatory agencies across North America. He has worked on transmission matters in SPP, MISO, PJM, New York, New England, ERCOT, CAISO, and WECC.

He 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.

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

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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

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