Transmission Planning and Benefit-Cost Analyses

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Transmission Planning Needs Urgent Improvements

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

Key Challenges in U.S. Transmission Planning

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

- Planners and policy makers **do not consider the full range of benefits** that transmission investments can provide, understating the expected value of such projects and how these **values change over time**
- Planners and policy makers do not sufficiently account for the **risk-mitigation and option value of transmission** infrastructure that can avoid the potentially high future costs of an insufficiently-robust and insufficiently-flexible transmission grid
- Most projects are build solely to address **reliability and local needs**; the substantial recent investments in these types of projects now make it more difficult to justify valuable new transmission that could more cost-effectively address economic and public policy needs
- Regional **cost allocation** is overly divisive, particularly when applied on a project-by-project (rather than portfolio- or grid-wide) basis
- Ineffective **interregional planning processes** are generally unable to identify valuable transmission investments that would benefit two or more regions

Preview: Best Practices Transmission Planning and Cost Allocation

Experience with effective planning and cost-allocation processes shows that they should:

1. Approach every transmission project as a **multi-value project**, able to address multiple drivers and multiple needs and be able to capture full range of benefits
2. Evaluate **projects** based on a **broad range of** transmission-related **benefits** (taking advantage of increasing experience to quantify economic, public policy, reliability, and avoided cost benefits)
3. Account for **uncertainty** by evaluating projects for a range of plausible future scenarios and sensitivities
4. Consider "**least regrets**" planning tools to reduce the risks of an uncertain future (and regrets of having either built or not built transmission)
5. Determine **cost allocation** based on the total benefits for the entire portfolio of projects (to take advantage of more stable and wide-spread benefits for portfolios)

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Quantify Transmission-Related Benefits for Individual Projects (or Synergistic Groups of Projects)

The wide-spread nature of transmission benefits creates challenges in estimating benefits and how they accrue to different users

▪ **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

Too Much Focus: Addressing Reliability and Local Needs

Transmission planning often is too focused on addressing reliability and local needs at lowest costs; risks building the "wrong" projects

- For example: what is the lowest-cost option to address a specific reliability need based on current forecasts? What is the lowest cost option to replace an aging facility?

The <u>least-cost transmission</u> solution to address specific need does <u>not</u> always offer highest-value, <u>lowest total costs</u> to customers:

- Up-sizing projects may capture additional economic benefits (market efficiencies, reduced transmission losses, reduced costs of future projects such as renewables overlay, reliability upgrades, plant interconnection, etc.)
- More expensive regional or interregional transmission may allow integration of lower-cost renewable resources and reduce balancing cost, losses, etc.
- Modest additional investments may <u>create option value</u> of increased flexibility to respond to changing market and system conditions (e.g., single circuits on double circuit towers)
- Least-cost replacement of aging existing facilities may mean lost opportunities to better utilize scarce rights of way
- Not take advantage of more robust and flexible solutions that mitigate short- and long-term risks

Production Cost Savings, the Most Common Metric, Misses Many Important Transmission-related Benefits

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

Adjusted Production Costs (APC) =

+ Production costs (fuel, variable O&M, startup, emission costs of generation within area)

+ Cost of hourly net purchases (valued at the area-internal load LMP)

– Revenues from hourly net sales (valued at the area-internal generation LMP)

Limitations:

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

We have a Decade of Experience with Identifying and Quantifying a Broad Range of Transmission-related Benefits

SPP 2016 RCAR, 2013 MTF

Quantified

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

Not quantified

8. reduced cost of extreme events
9. reduced reserve margin
10. reduced loss of load probability
11. increased competition/liquidity
12. improved congestion hedging
13. mitigation of uncertainty
14. reduced plant cycling costs
15. societal economic benefits

(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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WIRES

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May 2016

THE Brattle GROUP

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

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WIRES

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Akarsh Sheilendranath

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

Includes recommended approaches to quantify various benefits

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

BU
Boston University Institute for Sustainable Energy

The Value of Diversifying Uncertain Renewable Generation through the Transmission System

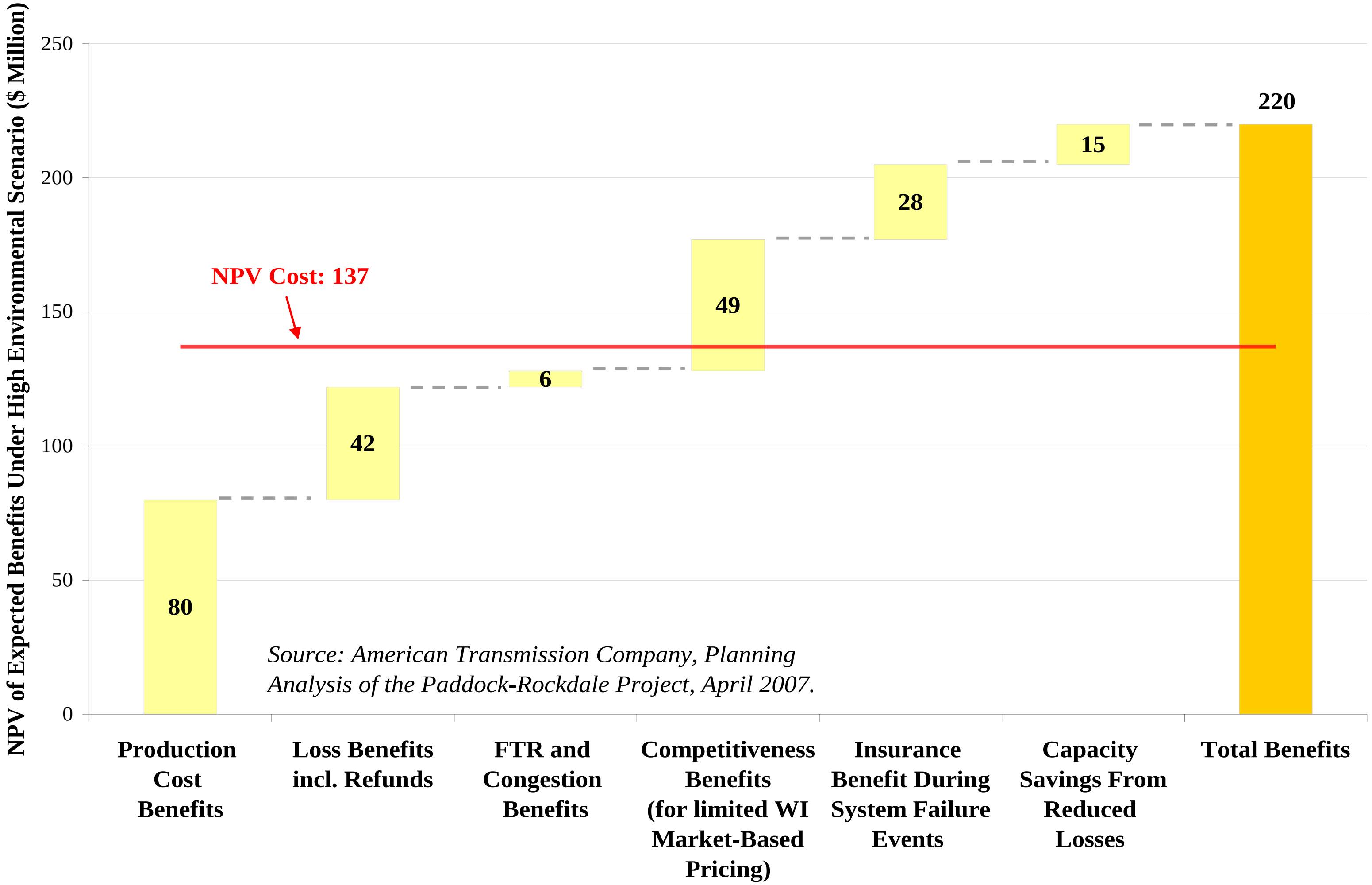
September • 2020

2013 WIRES Study: “Checklist” of Transmission Benefits and Best Practices for Quantifying Them

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

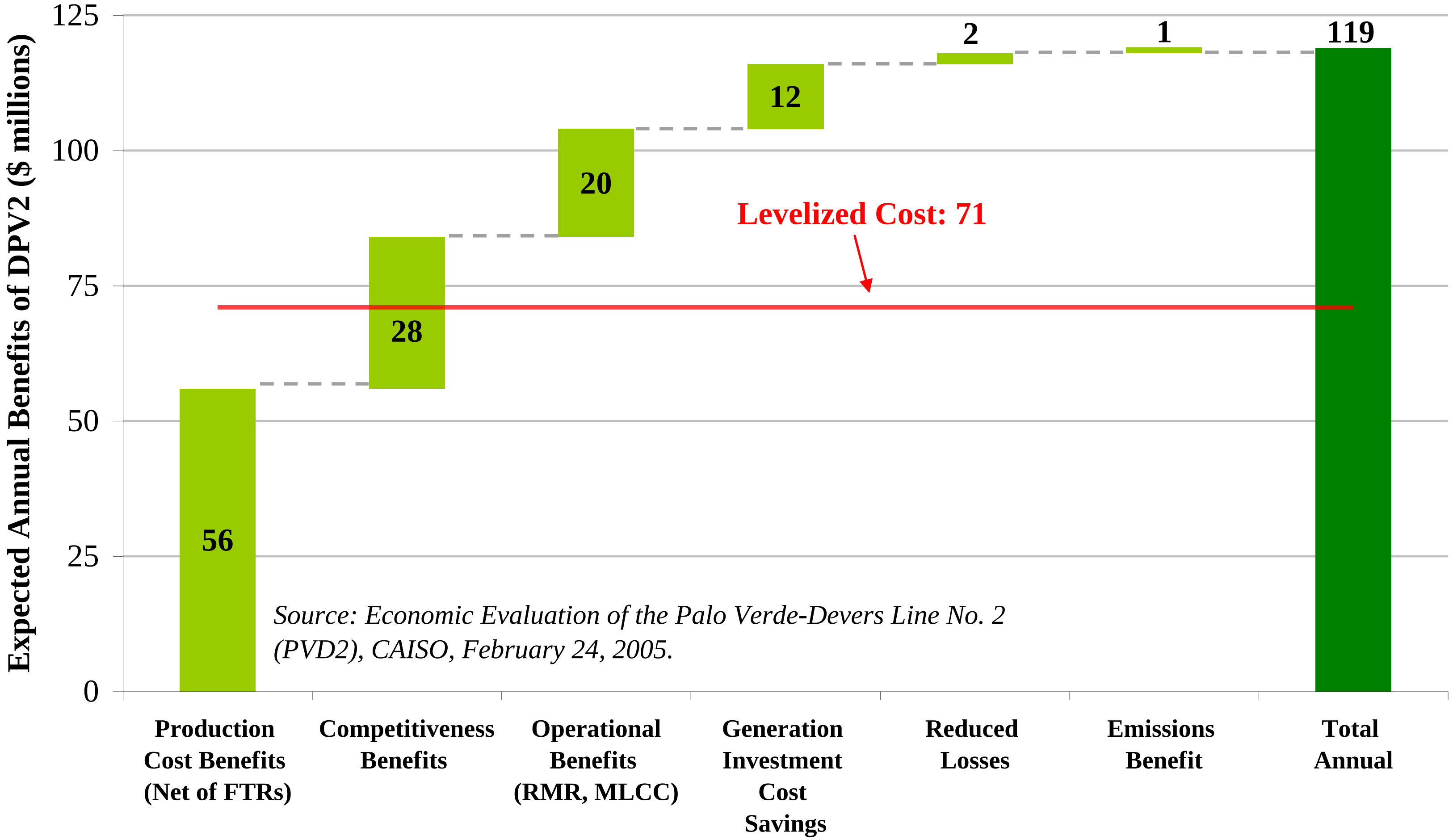
Example: Transmission Benefits and Costs in Wisconsin

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



Example: CAISO Transmission Project Benefits vs. Costs

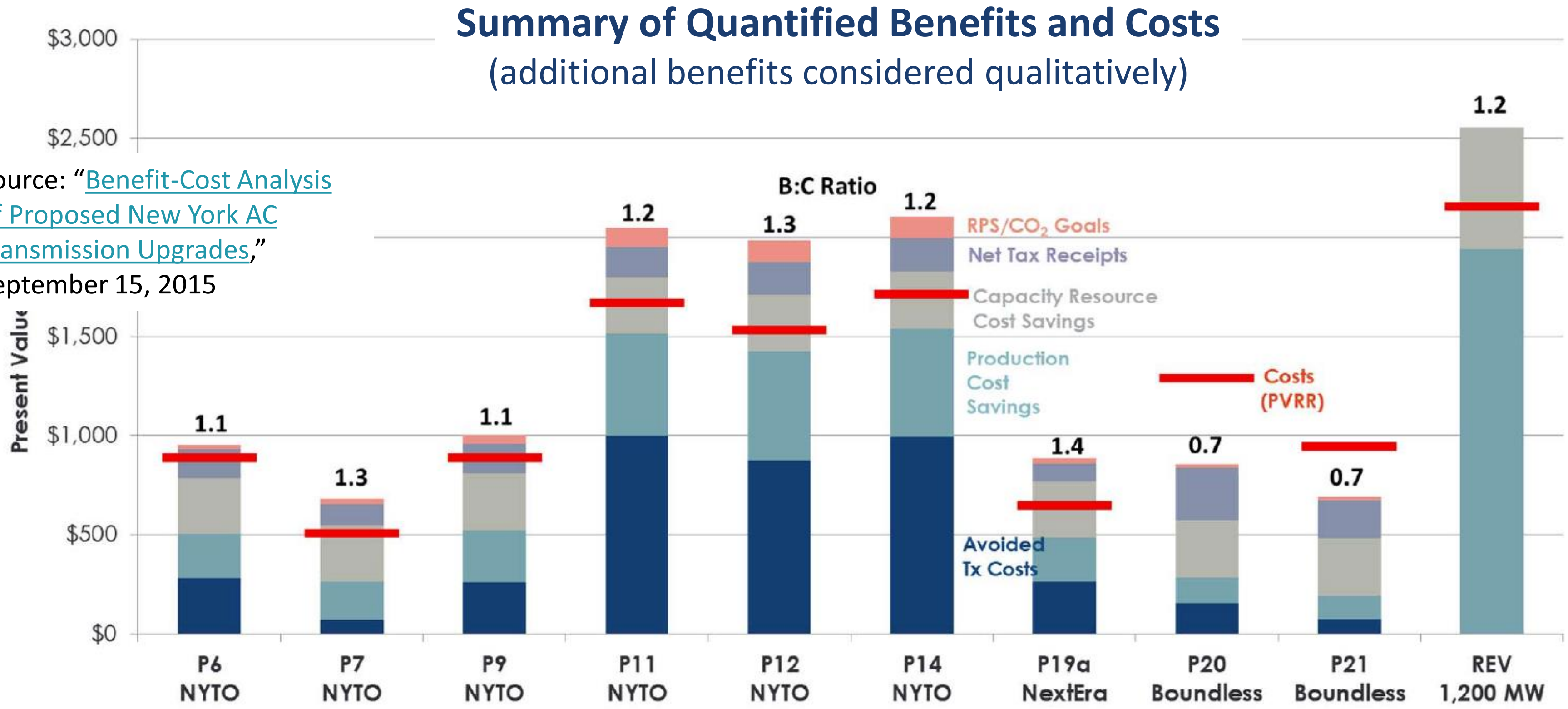
Total benefits of CAISO's DPV2 project exceeded project costs by more than 50%, but only if multiple benefits are quantified



Source: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2), CAISO, February 24, 2005.

Example: New York's (Multi-Value) "Public Policy" Transmission Planning Process

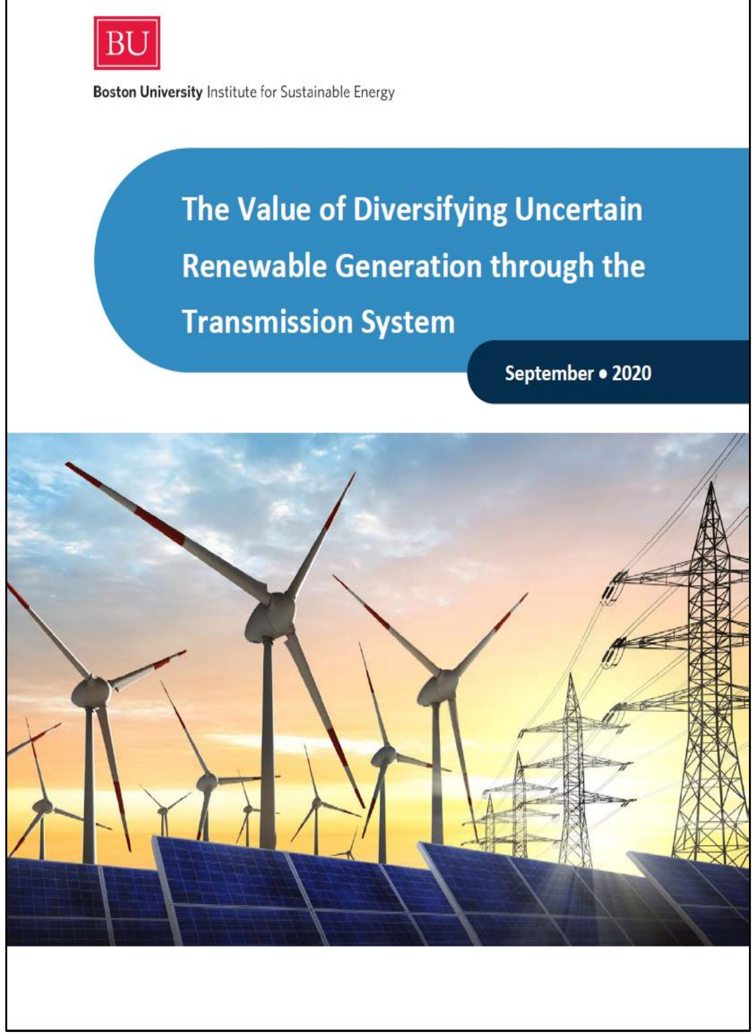
New York DPS recently modified its "public policy" transmission planning process by mandating that a full set of benefits be considered. Resulted in approval and competitive solicitation of two major upgrades to the New York transmission infrastructure



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

Additional: Renewable Generation Diversification Benefits

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



Our recent case study at Boston University's Institute of Renewable Energy (BU-ISO) demonstrates sizeable "diversification benefits" beyond those typically quantified for variable renewable generation with significant day-ahead forecasting uncertainty:

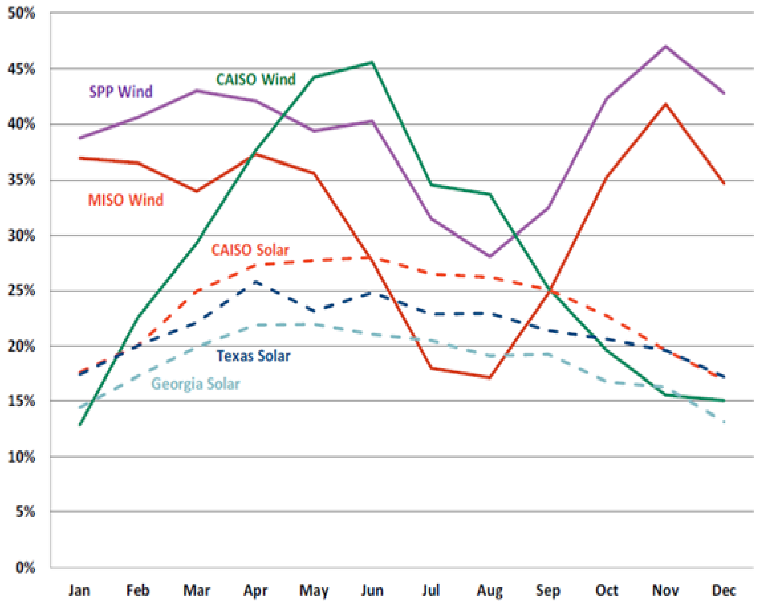
- **The benefits of unlocking the geographic diversity of variable renewable generation are large:** For grids with 10-60% renewable generation, the regional diversification through the transmission grid can reduce system-wide production costs by between 3% and 23% and renewable generation curtailments by 45% to 90% (all else equal)
- **Renewable generation and load uncertainty needs to be considered in measuring benefits:** Relative to conventional studies that are based on "perfect foresight," quantifiable benefits are 2 to 20 times higher when renewable generation and load uncertainty (the day-ahead forecasting error) is considered

With increasing renewable generation and load uncertainty, the geographic scope of a robust grid needs to exceed the size of typical weather systems. The benefits of doing so can be quantified.

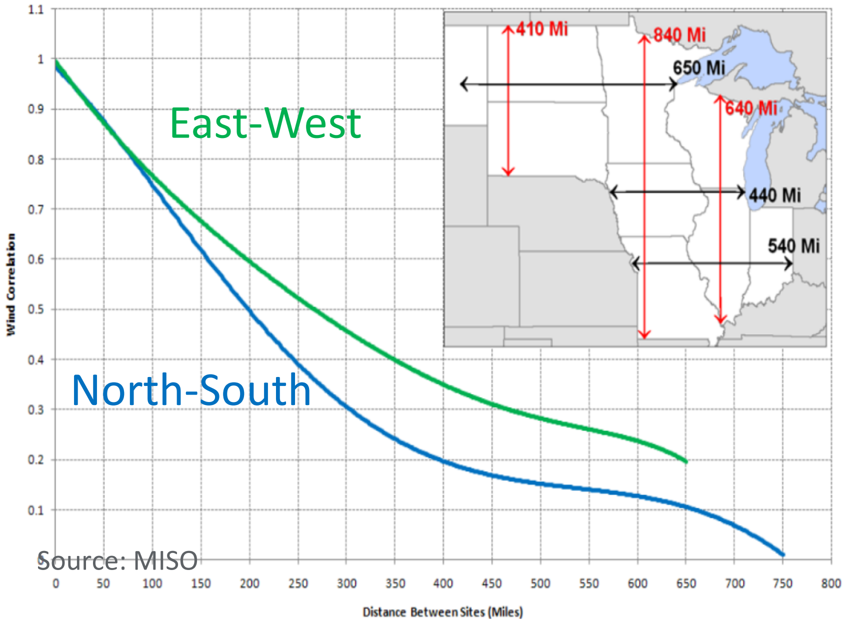
Diversity of Renewable Generation and Forecast Errors

Correlation of renewable generation variability can be diversified across technologies and geographically. Diversifying both the predictable and uncertain variability of renewable generation over large geographic areas can reduce system-wide uncertainty and lower costs. But by how much?

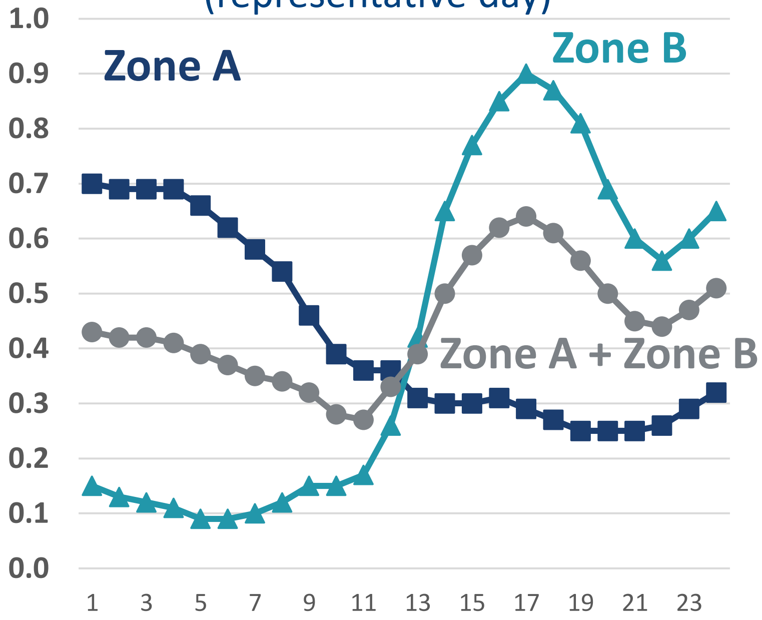
Monthly Wind and Solar Generation



Wind Correlation vs Distance in MISO



Hourly Wind Generation in Case Study
(representative day)



Note: Actual wind data from ERCOT for two sites that are approximately 300 miles apart

Day-ahead and intra-day forecast errors show similar geographic diversity

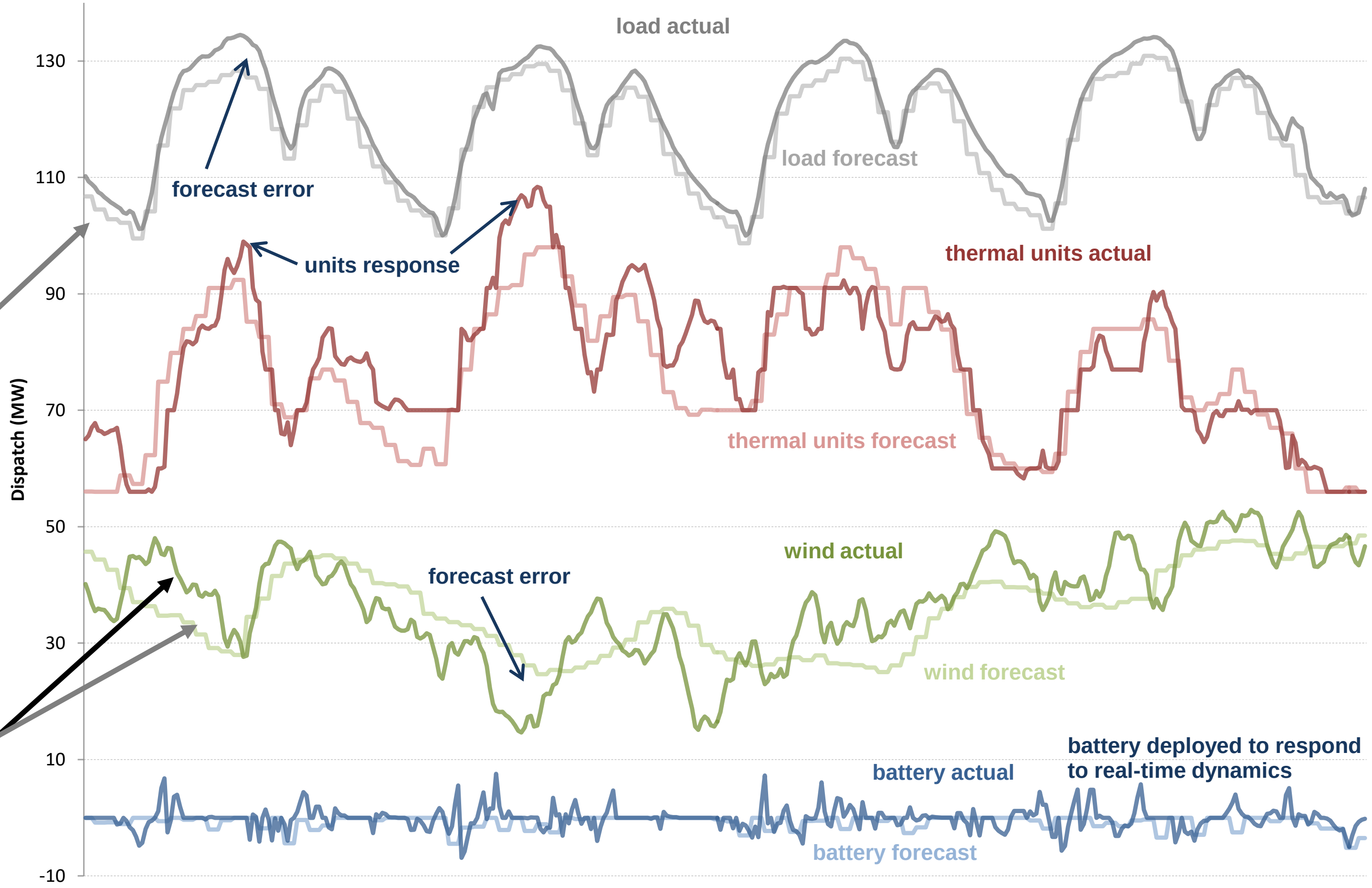
Forecast Uncertainty is a Major Driver of Dispatch Costs

Our study starts with the conventional "Perfect Foresight" study approach by simulating multiple scheduling horizons with day-ahead load and renewable generation forecasts

A "Perfect Foresight" simulation typically focuses on just one view, often the day-ahead

We additionally simulate the need to respond to uncertainty and intra-hour variance in real-time with a more limited set of resources, considering both scheduling and actual operations

Illustrative 4-Day Operations Simulation Summary

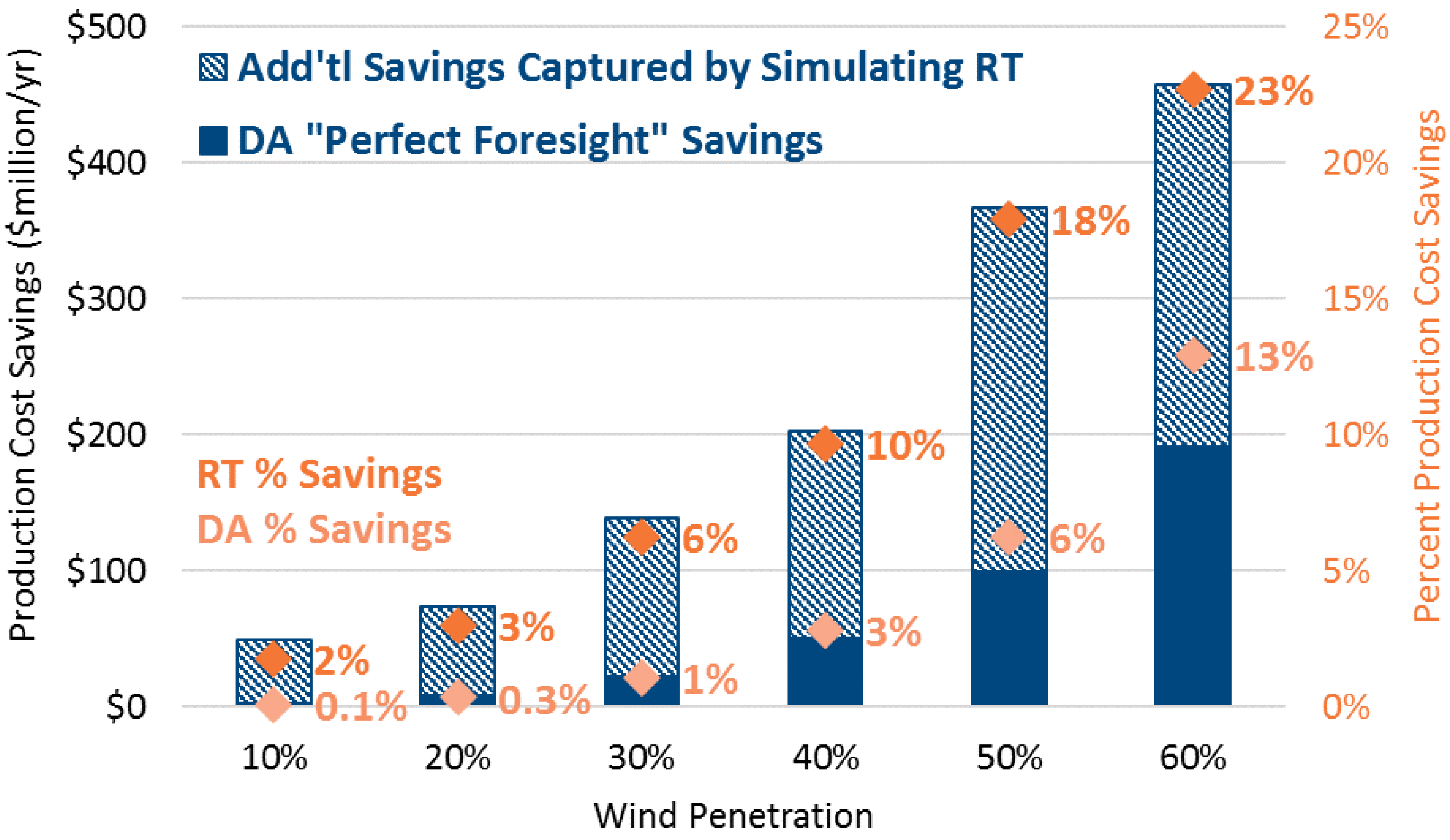


Dark lines are real-time "actual" outcomes

Light lines are day-ahead scheduling outcomes, based on forecasted conditions

Simulating Forecast Uncertainty → Substantially Higher Benefits

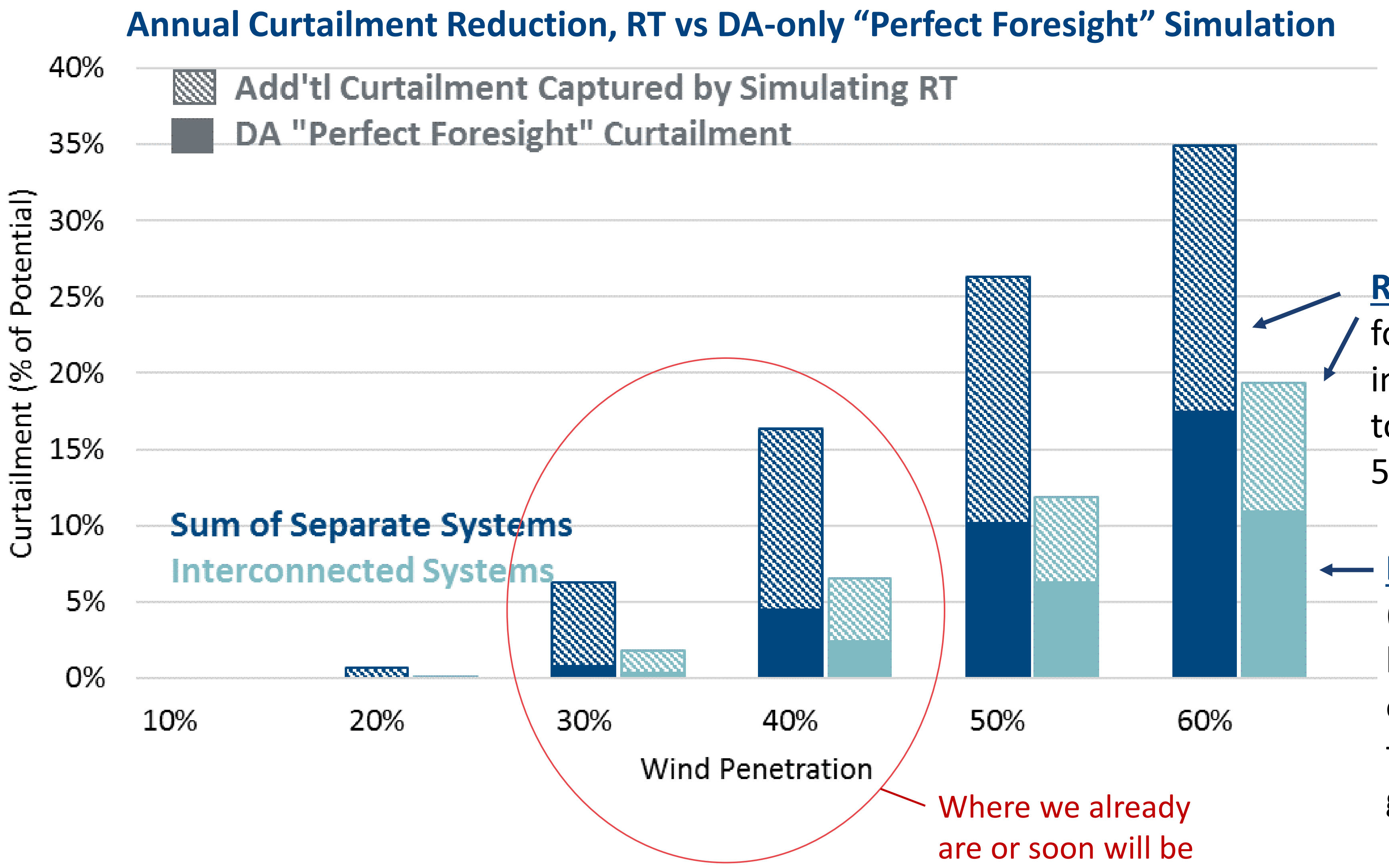
Annual Production Cost Savings, RT vs DA-only "Perfect Foresight" Simulation



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

RT Curtailments are Significantly higher than DA Curtailments



Real Time curtailments (due to forecasting uncertainty and intra-hour variance) dominate total curtailments at less than 50% renewable generation

Day Ahead curtailments (assuming perfect foresight of hourly generation) reach half of total curtailments at more than 50% renewable generation

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>
  - Does not consider the many potentially “regrettable circumstances” that could result in very high-cost outcomes
  - Focuses too much on the cost of insurance without considering the cost of not having insurance when it is needed
- **Probabilistic weighting assumes risk neutrality** and does not distinguish between investment options with very different risk distributions

Inadequate Transmission Creates High Risks 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 **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

Example: Better "Least-Regrets" Planning

"Least Regrets" analysis can help planners avoid decisions that reduce flexibility to respond to uncertain future market conditions

- The "least-regrets" option may not be **"least cost"** in any future (nor have the lowest cost on a probability-weighted average basis)

Total Cost to Customers of 3 Options in 4 Futures (Option 1 can be not building)

	Future 1	Future 2	Future 3	Future 4	Average
Option 1	$100m	$120m	$125m	$144m	**$122m**
Option 2	$105m	$121m	$128m	$134m	**$122m**
Option 3	$110m	$121m	$128m	$130m	**$122m**

Option 1 is **least cost** in Futures 1-3

Option 3 is **least cost** in Future 4

Difference Between Lowest-Cost Option and Maximum Regret of Each Option

	Future 1	Future 2	Future 3	Future 4	Max Regret
Option 1	--	--	--	$14m	$14m
Option 2	$5m	$1m	$3m	$4m	$5m
Option 3	$10m	$1m	$3m	--	$10m

Option 2 is **least regret** across all Futures

https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_13-05.pdf

Scenario Analysis Example: ATC's Paddock-Rockdale Project

In evaluating the Paddock-Rockdale Project, ATC evaluated <u>seven</u> 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 <u>net</u> 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
- Beneficial in most (but not all) futures
- Not investing in the project can leave customers up to $700 million worse off

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

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

Harder: regionally share costs of transmission projects "needed" to meet regional reliability standards

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

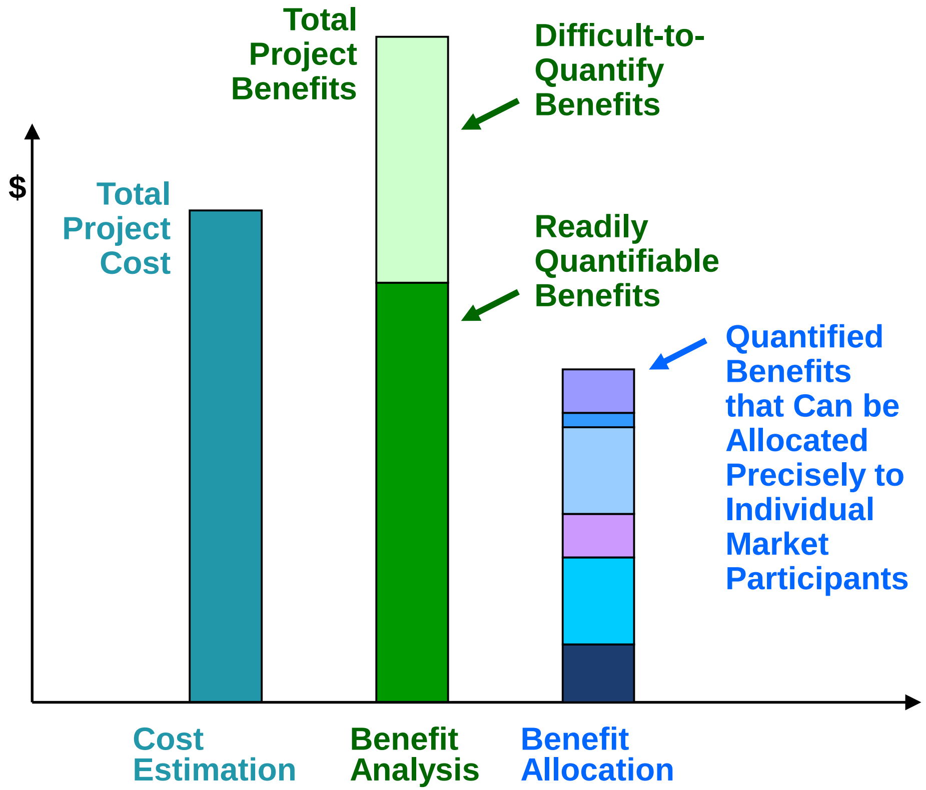
Hardest: share costs of transmission projects that provide broad regional economic or public-policy benefits:

- 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 are often ignored
- Large regional and inter-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

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 groups) will be rejected
    - Benefits that can be allocated precisely may only be a subset of total benefits
    - Avoid temptation to understate benefits in effort to reduce cost allocation to individual study participants
2. Evaluate how the cost of a portfolio of beneficial projects should be allocated based on 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 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**

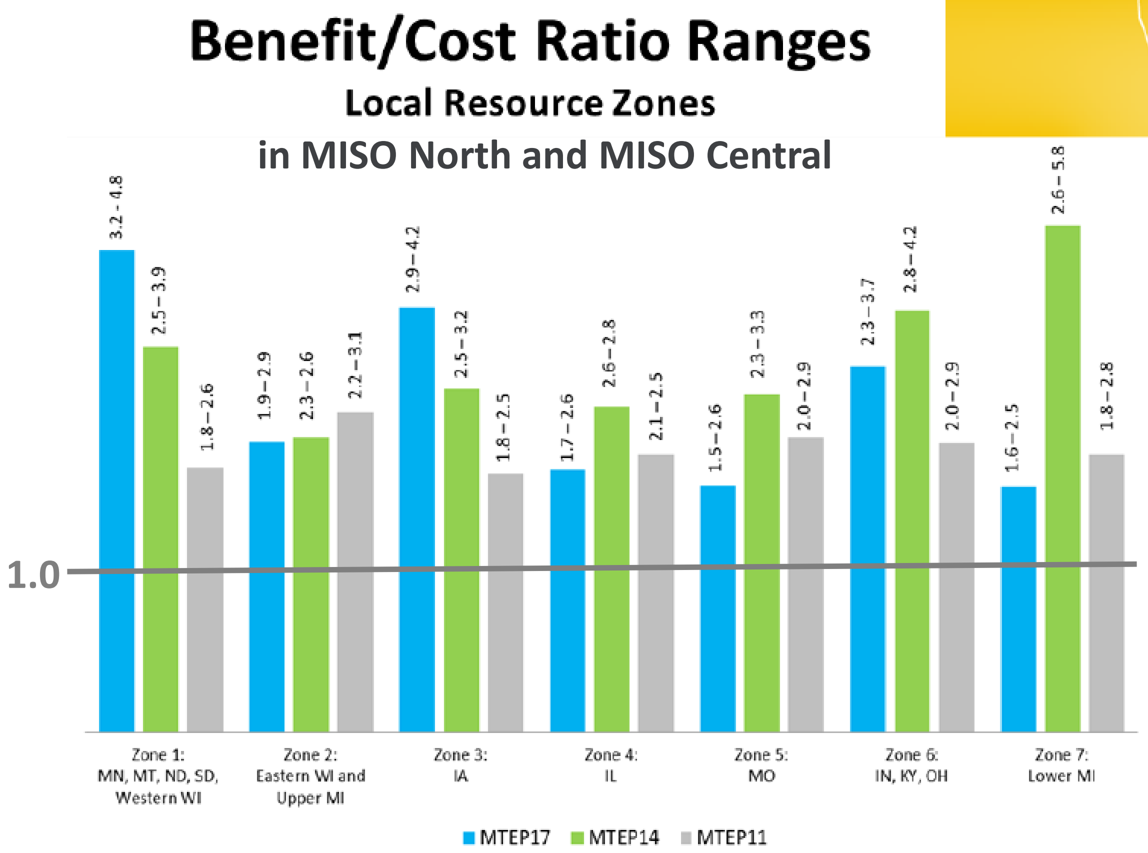
Examples of portfolio-based cost allocations:

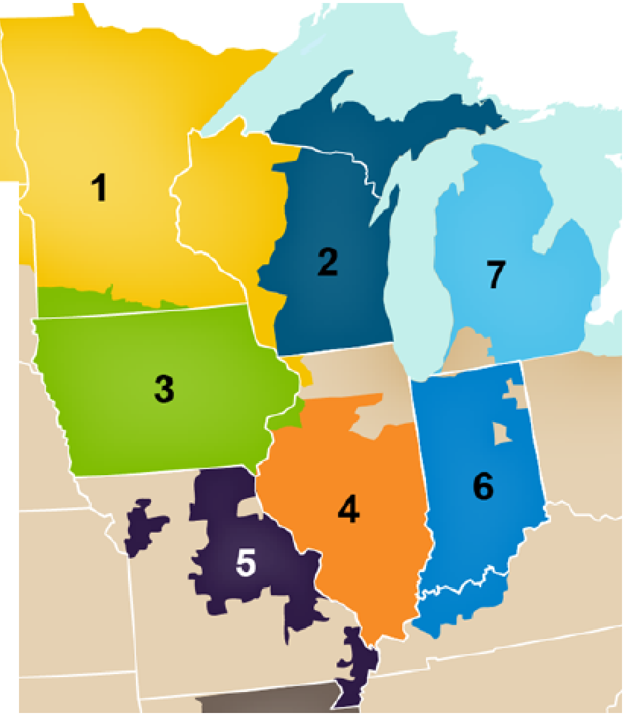
- SPP Highway-Byway (designed by RSC): Periodic review if benefits of all approved projects is roughly commensurate with costs of all projects
- MISO MVPs (with OMS input): Benefits of entire portfolio compared with allocated costs

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

Zonal + Local/Regional + Injection/Withdrawal Cost Allocation Proposal Developed by MISO and OMS in 2010

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

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

Layer	Local	Regional
Central below 345 kV	55%	45%
Central 345 kV	48%	52%
Eastern below 345 kV	64%	36%
Eastern 345 kV	59%	41%
Western below 345 kV	43%	57%
Western 345 kV	27%	73%
MISO-wide above 345 kV*	6%	94%

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

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

Source: Regional Expansion Criteria and Benefits (RECB) Task Force Meeting, March 11, 2010.

Content

National Studies Show Large Benefit of Interregional Transmission

Study	Region	Findings
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 (2020)	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	• Study results suggest relatively little interregional transmission would be needed to achieve 90% clean electricity, but its zonal expansion model does not utilize a nodal transmission representation nor chronological hourly granularity to analyze the operation of renewable resources, which underestimates the value of 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

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

Challenges Faced in Developing Interregional Transmission Infrastructure

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

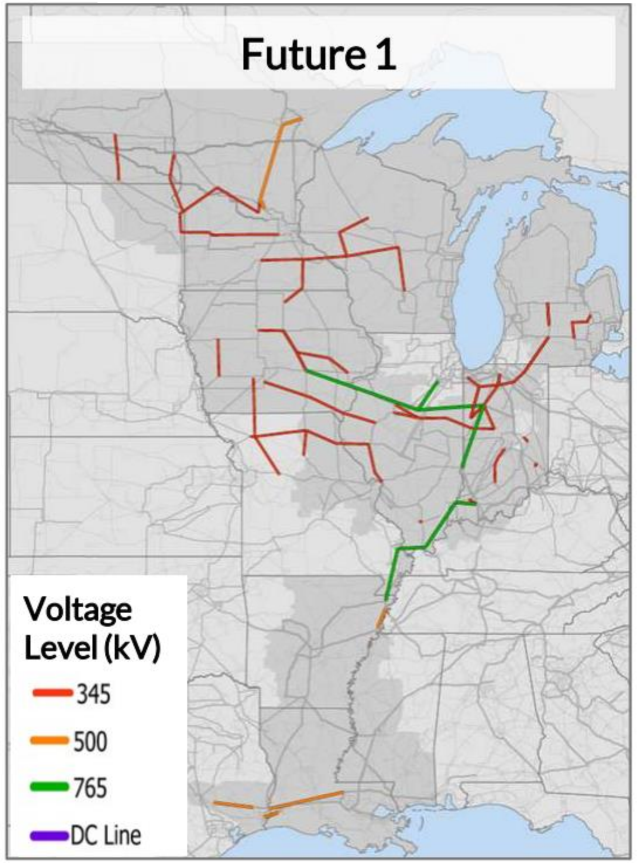
- Long-term transmission and generation planning tend to be disconnected, both in process and in analytical approach
- Many inter-regional renewable integration studies focus on renewable generation investments, but tend to use generic public-policy and transmission assumptions with limited credibility,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

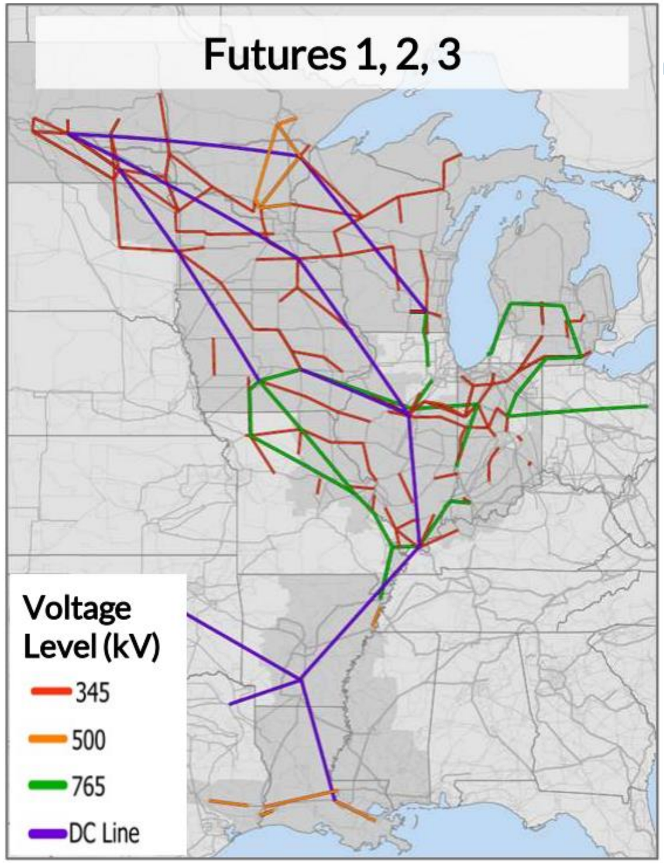
Regional planning will tend to pre-empt more valuable and cost effective interregional solutions

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 policy goals and reliability goals simultaneously
  - Considering diverse future scenarios
- 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?

Stakeholder Survey on Interregional Planning Barriers

- AEP sponsored a survey to identify barriers to interregional transmission planning:
  - Provides a brief overview of interregional transmission studies and why these studies have not yielded transmission projects
  - Documents the barriers to interregional planning
  - Summarizes the stakeholder feedback regarding barriers
- Interviewed policy makers, regulators, RTO planners, transmission developers, environmental groups, trade groups, and customers
- Identified 3 distinct category of barriers:
  1. Leadership, trust & understanding
  2. Planning processes and analytics
  3. Regulatory constraints

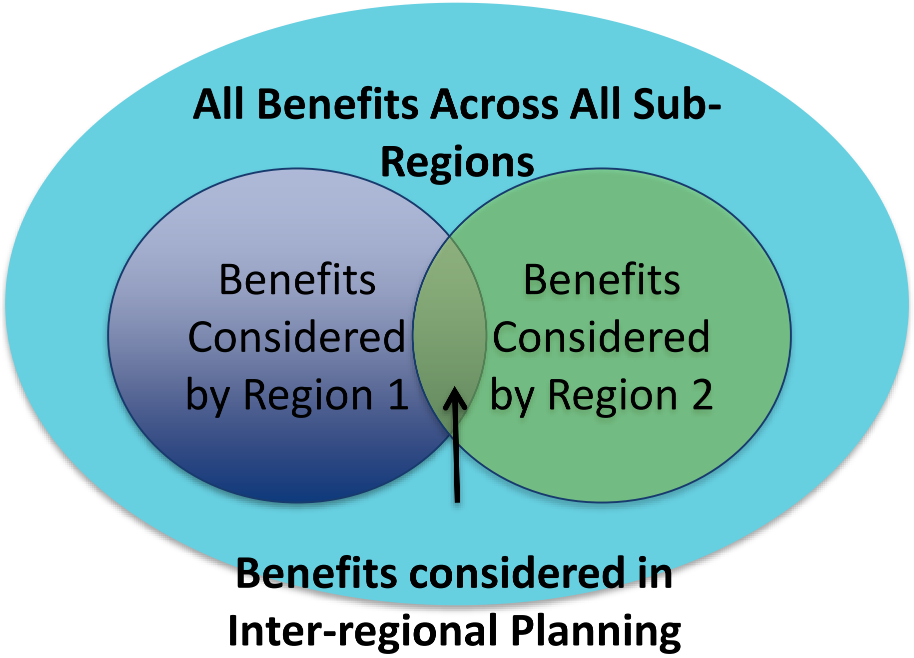
Identified Barriers to Interregional Transmission

A. Leadership, Trust & Understanding	1. Lack of aligned leadership from federal, state & RTO policy makers 2. Mistrust amongst states, RTOs, utilities, & customers 3. Utilities distrust solutions that result in loss of local control of transmission 4. Limited understanding of transmission issues, benefits & proposed solutions 5. Misaligned interests of RTOs, TOs, generators & policymakers 6. 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

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 <u>combined benefits</u> 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.

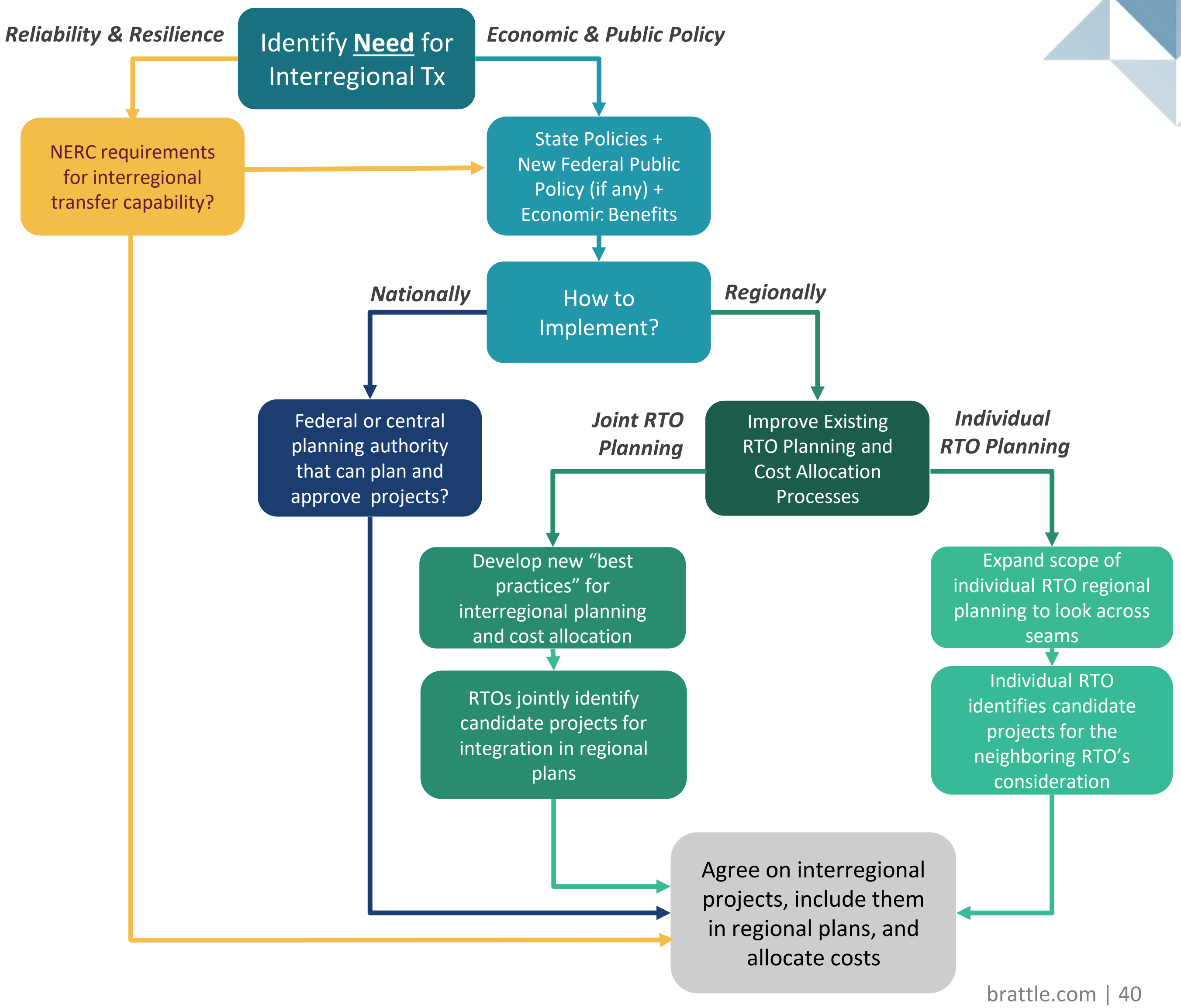
Projects Considered in MISO-PJM Planning:
(as Ordered by FERC)

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 could be pursued simultaneously, yielding projects through:
  - **New NERC requirements?**
  - **New Federal planning?**
  - **Improved joint RTO planning**
  - **Expanded planning by individual RTOs**



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Summary and Recommendations

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

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

In addition: Focus less on addressing near-term reliability and local needs, but more on infrastructure that provides greater flexibility and higher long-term value at lower system-wide cost

- Recognize that every transmission project offers multiple values
- Lowest-cost transmission is not "least cost" from an overall customer-cost perspective

Recap: Best Practices Transmission Planning and Cost Allocation

Experience with effective planning and cost-allocation processes shows that they should:

1. Approach every transmission project as a **multi-value project** to recognize multiple needs and benefits
   - Particularly important for interregional transmission projects, since a project may address different needs in different regions
2. Evaluate **projects individually** based a **broad range of** transmission-related **benefits**
   - Recognize all economic, public policy, reliability, and avoided cost related benefits
   - Take advantage of increasingly-extensive industry-wide **experience** with quantifying these benefits
3. Account for **uncertainty** by evaluating projects for a range of plausible future scenarios and sensitivities
   - Use **scenarios** of plausible **long-term** futures (to explicitly recognize that the future is uncertain)
   - Use **sensitivities** to analyze **short-term** uncertainties that exist in every "future" (e.g., severe weather, fuel-price spikes)
4. Consider "**least regrets**" planning tools to reduce the risk that some future outcomes may lead to:
   - Regret that the cost of **building** the project exceeds the project's benefits
   - Regret that **not building** the project results in very-high-cost outcomes

   (Reducing the cost of both types of outcomes is necessary to reduce the project's overall risk in light of uncertain futures)
5. Determine **cost allocation** based on the total benefits for the entire portfolio of projects
   - Portfolio-wide benefits tend to be **more evenly-distributed and stable** over time than the benefits of individual projects
   - Broader distribution of benefits **reduces contentiousness** of cost allocation and allows for simpler cost allocation approaches (e.g., load ratio shares)

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

His transmission work has focused on analyzing transmission needs, transmission benefits and costs, transmission cost allocations, and transmission-related renewable generation challenges for independent system operators, transmission companies, generation developers, public power companies, and regulatory agencies across North America.

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

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Our Practices and Industries

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

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- Bankruptcy & Restructuring
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- Commercial Damages
- Environmental Litigation & Regulation
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- International Arbitration
- International Trade
- Labor & Employment
- Mergers & Acquisitions Litigation
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