The Role of Transmission in the Future Southeast Power System

Transmission, Siting, and Permitting Reform in the Southeast

PREPARED BY

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PREPARED FOR

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Speaker Information

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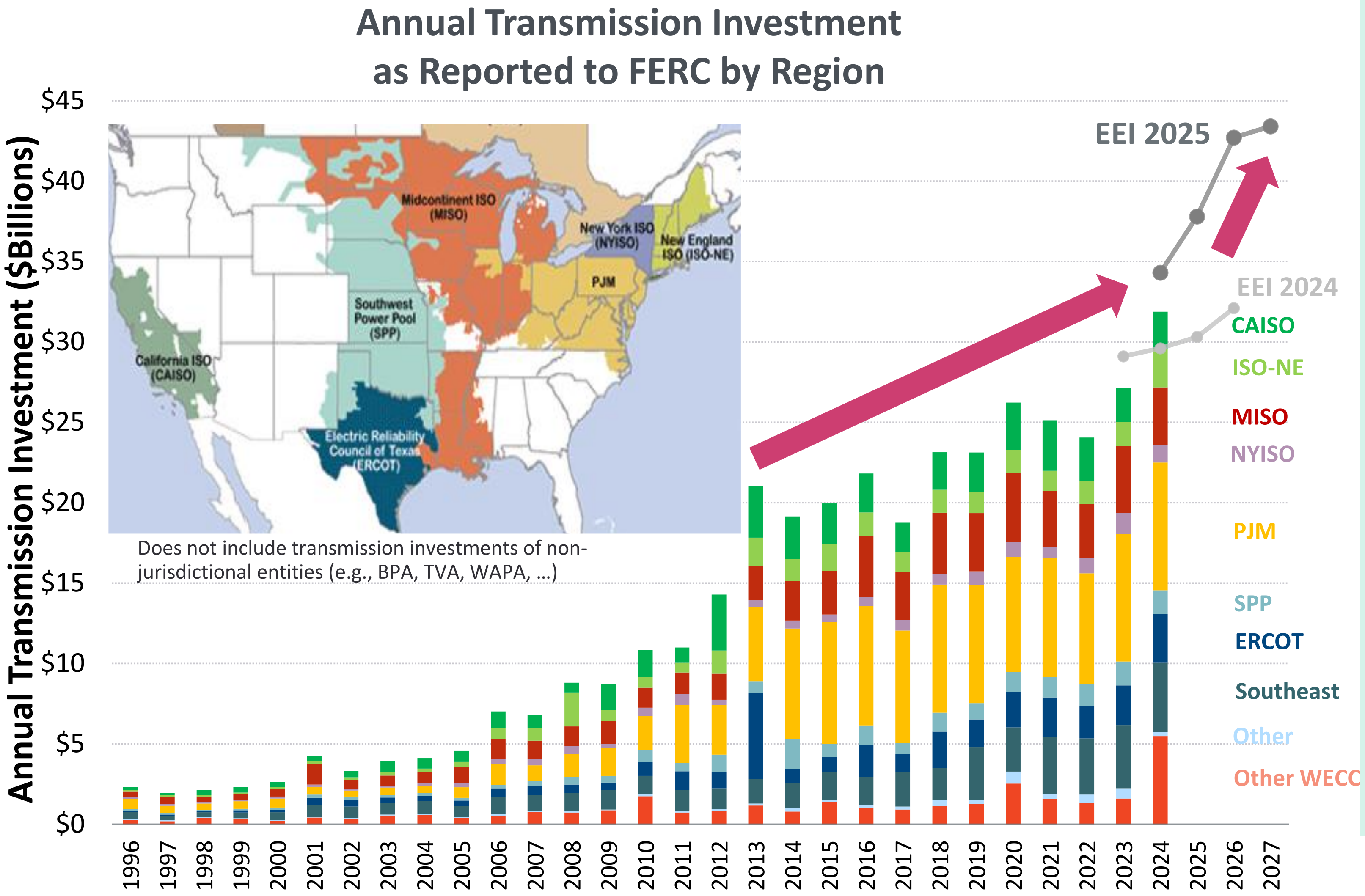
15 years of experience in electric power industry planning and regulatory analysis, including generation & transmission planning

Support utilities, regulators, developers, and RTOs with transmission planning in all areas of the country, including SERTP, FRCC, ERCOT, SPP, MISO, and non-RTO WECC

Co-author of *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* highly cited by FERC in Order No. 1920 (link)

Recent projects: Duke IRP & transmission planning (*CCEBA*), LRTP Tranche 2.1 FERC complaint (*MISO*), TVA IRP (*SREA*), FRCC O.1920 compliance (*EDF*), resource planning for data centers (*Wisconsin Electric*), and transmission benefits analysis (*Dairyland Power Coop*)

Transmission Costs Have Risen Dramatically and Keep Rising!



Transmission investment increased from \$3 to \$30 billion since 1990s and projected to reach \$45 billion!

- About 90% based on reliability needs (without benefit-cost analysis)
- About 50% based on "local" utility criteria (aging assets; without going through regional planning processes)
- Few projects are justified based on multi-driver regional planning studies outside of MISO
- Longer and higher voltage transmission projects are coming, planned for early 2030s

Sources: The Brattle Group analysis of FERC Form 1 Data; EEI "Historical and Projected Transmission Investment" most recent accessed here https://www.eei.org/-/media/Project/EEI/Documents/Resources-and-Media/bar_actual_and_projected_trans_investment.pdf

Why Isn't Reliability-Based Transmission Planning Enough?

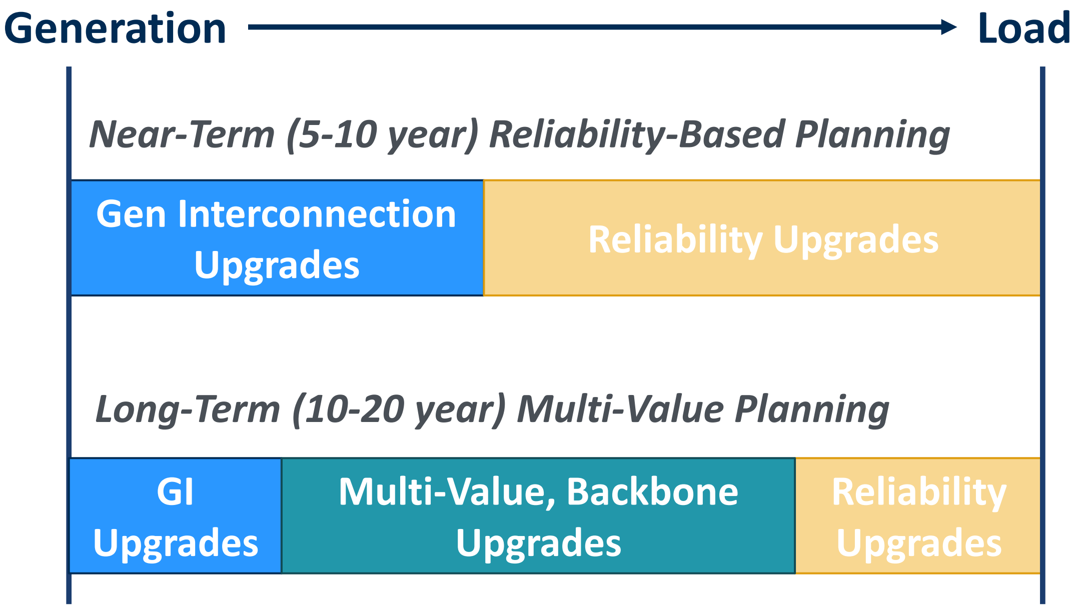
Role of transmission: Provide reliable and cost-effective network to connect generation to load now and in the future; planned in advance of need due to time to build

What is the purpose of Reliability Studies? Identify upgrades to ensure reliable service under future system conditions with projected generation resources and load

What do Multi-Value Studies evaluate? Whether upgrades can reduce costs more than the cost of the transmission itself

- Dispatch lower-cost generation during normal and extreme conditions (e.g., gen outages during winter storms, heat waves)
- Reduce energy losses and both capacity and energy costs
- Reduce total generation capacity needed to serve load by taking advantage of load diversity and resource diversity across region
- Access lower-cost generation resources (e.g., mine-mouth coal in the West and high-quality wind resources in the Great Plains)
- Avoid future transmission upgrades for asset condition projects, generator interconnection upgrades, or reliability needs

Illustrative Transmission Planning Approaches to Reliably Serve Load



Note: Does not include Transmission Service Requests.

Experience Quantifying Transmission-Related Cost Savings

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

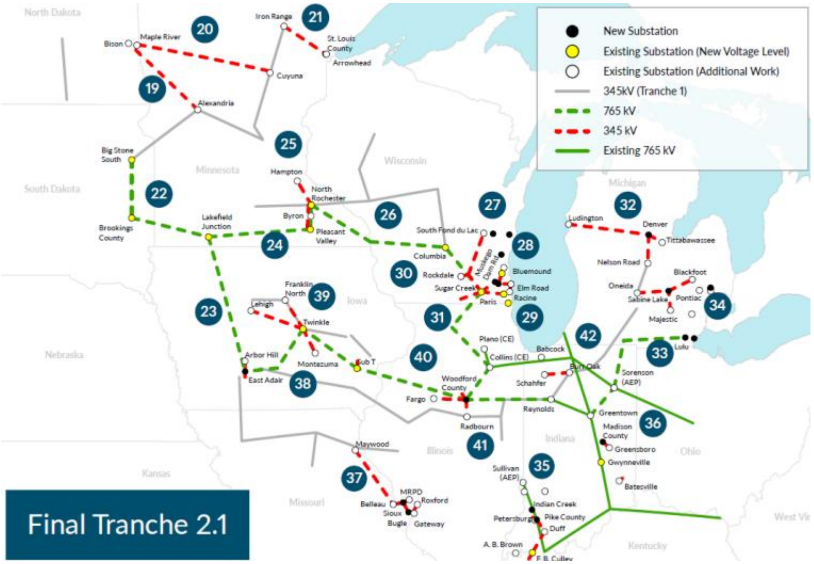
MISO LRTP Tranche 2.1 Multi-Value Planning Analysis

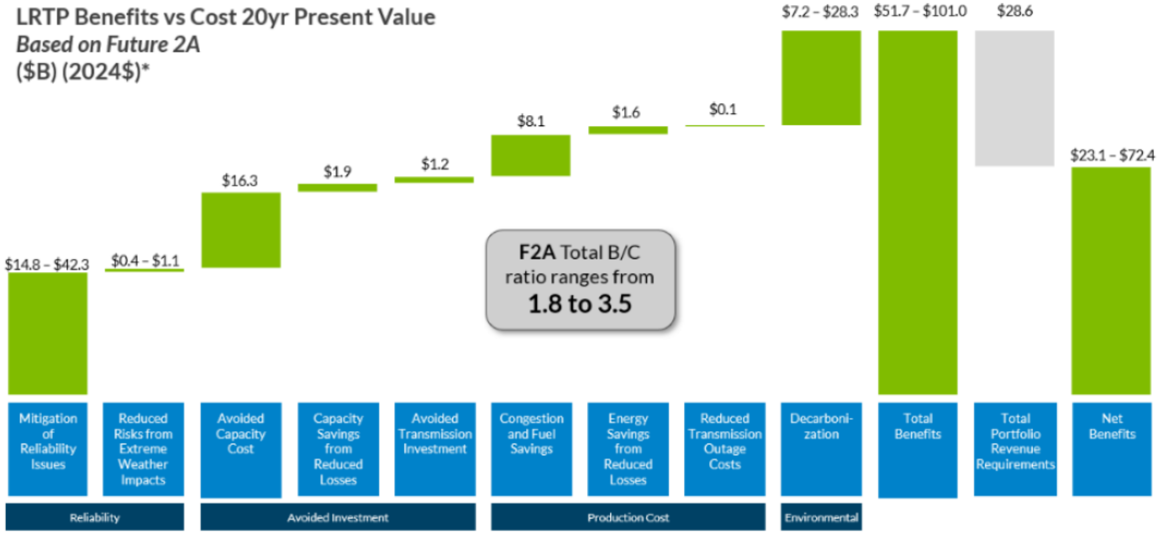
MISO completed the Long-Range Transmission Planning (LRTP) Tranche 2.1 study for the Midwest subregion, identifying a multi-value need for a **$29B portfolio of 765 kV projects**

- Utilized 3 scenarios based on load forecasts, member resource plans, and stakeholder input
- MISO added resources to meet demand and sited resources based on GI queue, siting study, and stakeholder input

MISO estimated net cost savings and other benefits of **$6-33B in Future 1A and $23-72B in Future 2A over 20 years**

- Benefits primarily derived from Mitigation of Reliability Issues, Avoided Capacity Costs, Generation and Fuel Savings, and Decarbonization

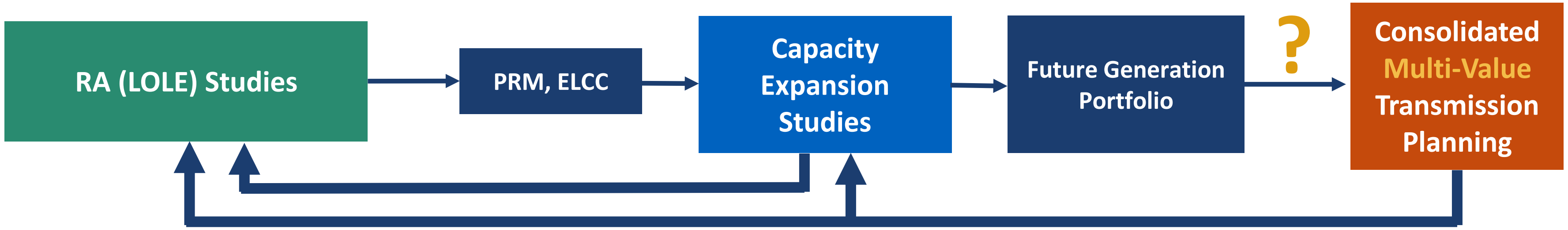




Integrated Generation and Transmission Planning

Option 1: Iterative RA, capacity expansion, and multi-value transmission planning

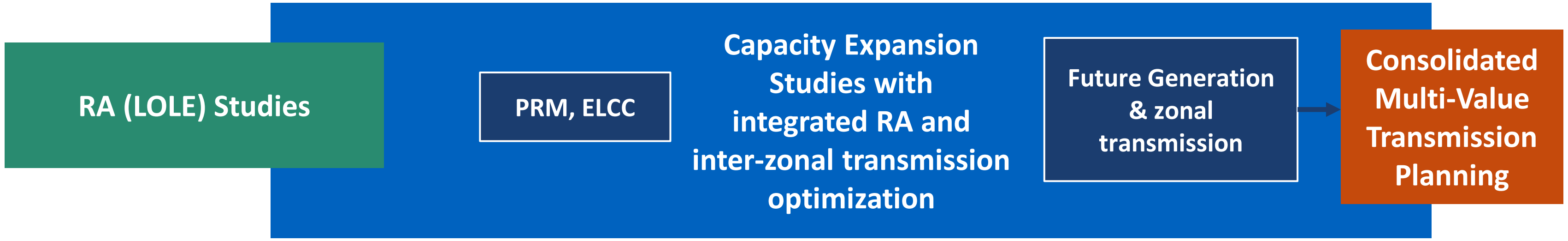
- RA value of transmission explicitly quantified in multi-value transmission planning (e.g., MISO LRTP)
- Iterative either within same planning cycle or (at least) across subsequent planning cycles



Most utilities (1) do not include IRP generation portfolios in transmission studies and (2) only consider Reliability-driven needs

Option 2: Capacity expansion modeling co-optimized with RA and zonal transmission

- Capacity expansion models with integrated RA and zonal transmission co-optimization
- Offers more optimal starting point for detailed transmission planning, endogenously capturing RA value
- Requires expansion model with calibrated/verified RA and transmission expansion representation
- Example: SPP Future Energy and Resource Needs Study (FERNS)

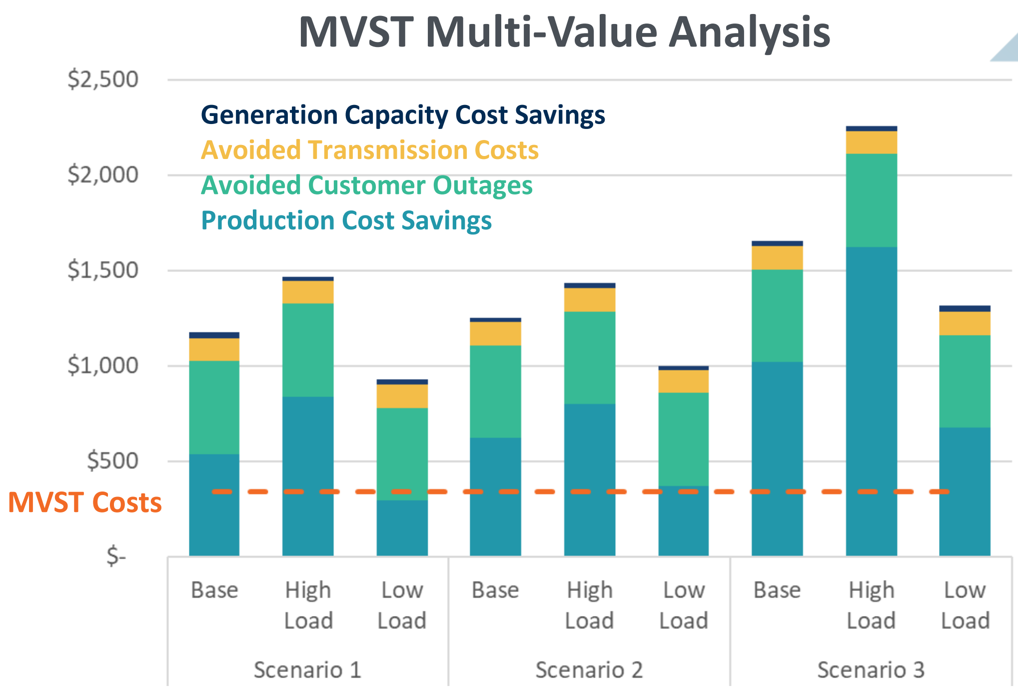


CTPC/Duke Multi-Value Strategic Transmission Study

NCUC required Duke to add a **proactive, scenario-based Multi-Value Strategic Transmission (MVST) study** to its FERC-regulated local planning tariff

2024 MVST study identified $353 million in upgrades that provide **$1.2-1.7B in cost savings and other benefits** to the Duke system (up to $2.3B in the Scenario 3 High Load case)

CTPC is starting its second MVST in 2026



IRP-based Scenarios
Identify reliability-based needs for future scenarios based on IRP-developed generation portfolios

Alternative Solutions
Consider existing line upgrades, greenfield projects, GETs, advanced conductors, RAS, storage

Portfolio Evaluation
Evaluate portfolio of solutions over the life of the assets to resolve needs

Benefits Analysis
Avoided capacity costs, cost savings from reduced losses, congestion and fuel cost savings, avoided outages, and avoided transmission costs

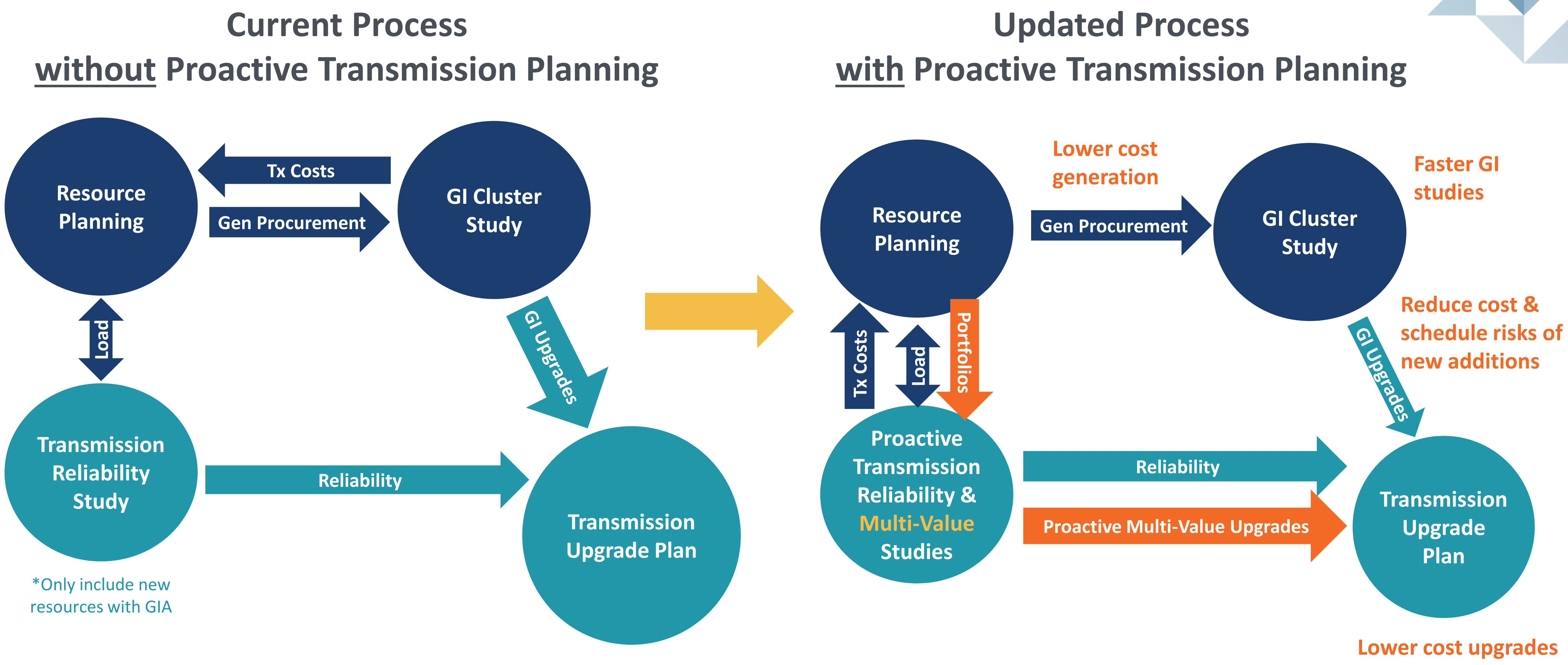
What Does MVST Add to Duke's Transmission Planning Process?

Quotes from Duke IRP Transmission Panel Rebuttal Testimony (posted May 14, 2026):

- "Through the MVST Study process, the Companies can **proactively identify "no regrets" transmission projects that will be required under the most likely future scenarios** and bring those projects in-service before the Companies and its customers experience issues with **reliability or congestion**."
- "Public Staff supports the Companies' incorporation of MVST planning as providing for a **more robust, holistic study process.** The Public Staff stated that 'MVST should help **enable faster, more cost-effective interconnection of new generation** that is needed to serve load.' The Public Staff acknowledges that the MVST Study process is **not required** for compliance with FERC Orders on Local Transmission Planning but that it **can help support CPIRP least-cost planning requirements**."
- "Witness Hagerty correctly recognizes that '[t]he MVST successfully developed a set of future scenarios for the CTPC to study that is integrated with the Duke resource planning study, **providing an important link between resource planning and transmission planning that did not previously exist for the Duke service territory**.'…"He testifies that '[t]he MVST successfully identified several upgrades that provide significant benefits to the system and **would not have been built otherwise, reducing costs to ratepayers and supporting future generation additions and load growth**.'"

Source: Rebuttal Testimony of Dewey S. Roberts II and Jing Shi of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC.

Proactive Transmission Planning Reduces Generation Costs and Risks



Southeast Must Invest in Regional Transmission to Cost-Effectively Meet Growing Demand and Maintain Reliability

Facing unprecedented load growth and increasing reliability risks, Southeast utilities need to invest in their regional transmission systems to improve reliability and reduce costs.

- **4x Increase in Transmission Costs over Last 20 years:** Spending on utility-specific upgrades increased during a period of moderate load growth due to aging infrastructure and new generation capacity needs
- **20 GW of Load Growth in Next 10 Years:** Serving the rapid 25% increase in load cost-effectively requires identifying opportunities for regional projects to supplement local upgrades and reduce system costs
- **80 GW of New Generation to Serve Load:** New generation (gas, solar, and storage) faces cost & schedule risks due to limited transmission capacity, which can be mitigated by proactive regional upgrades
- **Increasing Severity & Frequency of Winter Storms:** Winter storms have created new reliability risks over last 5 years that drive a need for both regional and interregional upgrades

Yet, all recent Southeast transmission upgrades are based on utility-specific local transmission planning* that has not considered the benefits of supplementing local upgrades with larger, more cost-effective regional and interregional transmission projects.

*In some portions of the Southeast (e.g., GA, NC, and SC), utilities within the same state collaborate on "local" reliability-driven transmission planning for their service territories.

Source: Brattle SERTP Report.

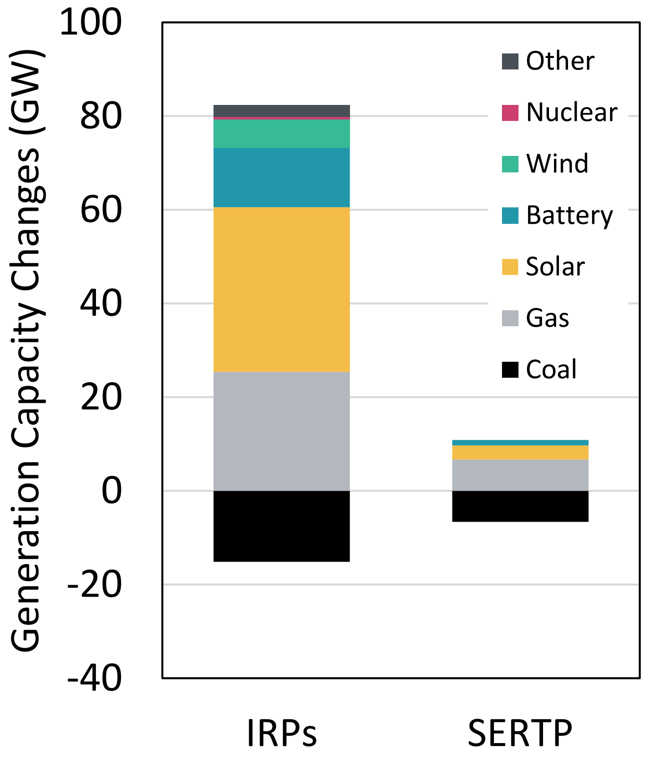
SERTP Process Results in Insufficient Regional Transmission

Southeastern Regional Transmission Planning (SERTP) completes an annual "bottom-up" regional planning process that has several limitations for identifying beneficial regional upgrades.

- **Limited Scope**: SERTP aggregates local planning studies and confirms regional reliability for a single future load scenario, failing to utilize scenarios developed in Sponsors' resource planning studies
- **Inconsistent with IRPs**: SERTP studies include just 12% of the 80 GW of new generation identified as needed by the most recent IRP studies
- **Lack of Transparency:** SERTP provides limited information on transmission costs, violations, or alternatives studied to meet needs
- **No Regional Projects Approved**: SERTP analyzes regional alternatives based on a limited set of system needs, resulting in no regional upgrades in 11 years of SERTP regional planning studies

Existing SERTP planning process will not identify and approve the most cost-effective transmission infrastructure to reliably serve future load

IRP vs SERTP 2035 Generation Changes
(TVA, Duke, LG&E/KU, GPC)



Source: Brattle SERTP Report.

Case Study: SERTP-Identified Upgrades Reduce Costs

To demonstrate the value for regional transmission, we performed a high-level analysis (based on historical data) of three 500 kV upgrades SERTP identified in its 2024 process

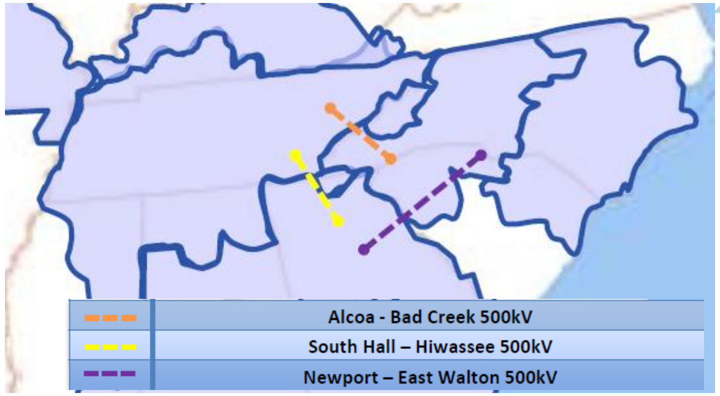
We estimated $8 billion of benefits compared to $5 billion in costs, resulting in at least $3 billion of net benefits

- Production cost savings: $2.9 billion (*range*: $2.0–3.6 billion)
- Load diversity cost savings: $3.3 billion (*range*: $0.9–6.0 billion)
- Resilience benefits: $1.6 billion (*range*: $0.7–2.3 billion)
- Additional potential benefits: avoided reliability and interconnection upgrade costs, greater production cost savings with increased solar/wind additions and reduced generation costs

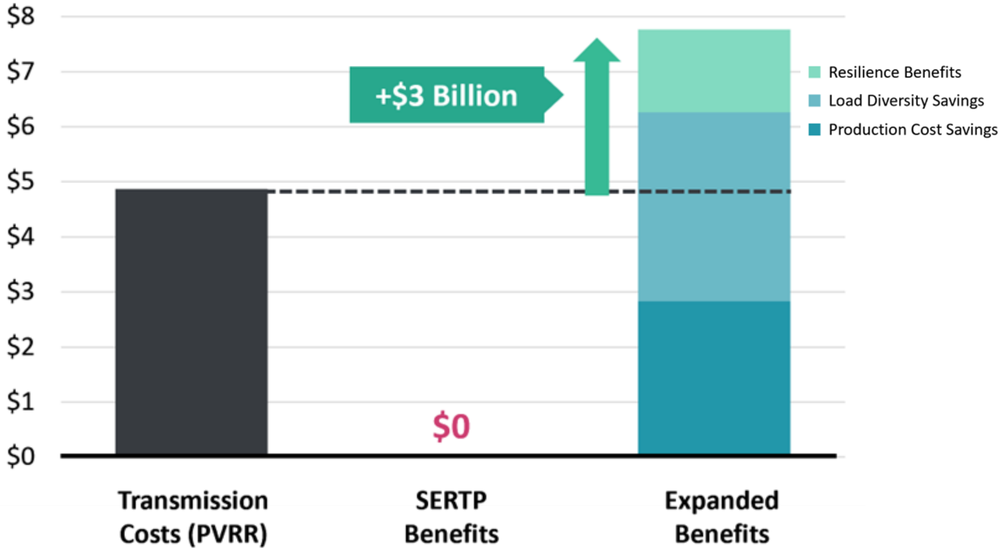
Regional transmission can reduce system costs when a broader scope of cost savings and other benefits are analyzed

By contrast, SERTP's very narrow view of benefits based solely on avoided local transmission costs identified no cost savings

SERTP-Identified Regional Projects

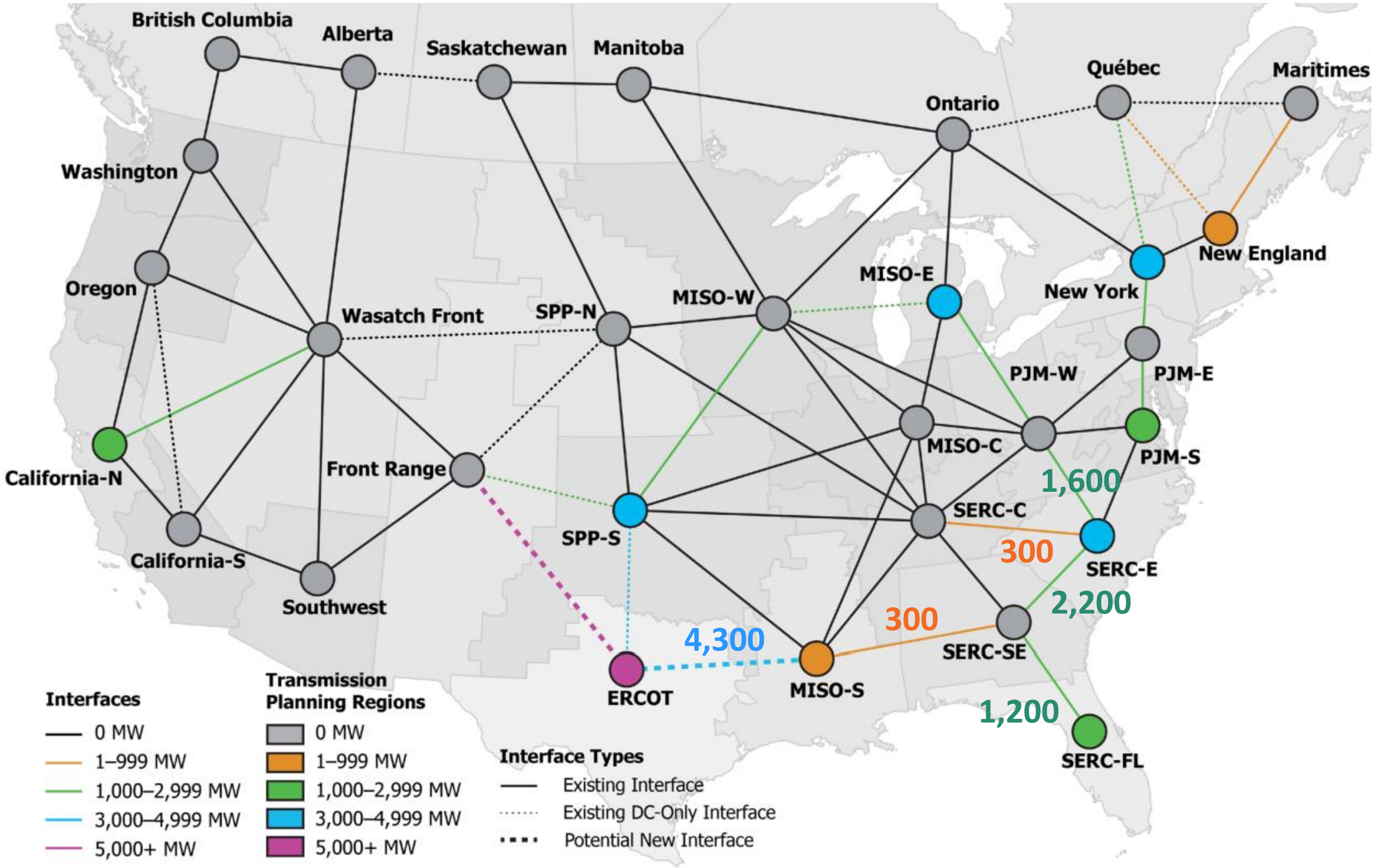


Estimated Net Benefits of Regional Projects



Source: Brattle SERTP Report.

NERC ITCS: “Prudent” Reliability-Driven Expansions by 2033



Transmission Planning Region	Additional Transfer Capability (MW)	Interface Additions (MW)
ERCOT	14,100	Front Range (5,700) MISO-S (4,300) SPP-S (4,100)
MISO-E	3,000	MISO-W (2,000) PJM-W (1,000)
New York	3,700	PJM-E (1,800) Québec (1,900)
SPP-S	3,700	Front Range (1,200) ERCOT (800) MISO-W (1,700)
PJM-S	2,800	PJM-E (2,800)
California North	1,100	Wasatch Front (1,100)
SERC-E	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	1,200	SERC-SE (1,200)
New England	700	Québec (400) Maritimes (300)
MISO-S	600	ERCOT (300) SERC-SE (300)
TOTAL	**35,000**	

Source: Interregional Transfer Capability Study (ITCS) - Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)

Recommendations to Enhance SERTP Regional Planning that will Reduce Costs and Increase Reliability of the Southeast Grid

I. Improve Existing Processes

1. **Increase transparency** of study assumptions, approach, and results
2. **Engage state commissions and energy agencies** to participate in process and ensure results reduce costs and address state policies
3. Expand solutions studied to reflect **least-cost transmission "loading order"** that maximizes existing grid, upgrades existing lines, and builds new lines where necessary

II. Expand Planning Capabilities

4. Develop **multiple scenarios based on recent IRPs** to plan for a range of load and generation portfolios
5. Accurately identify congestion and quantify cost savings of regional upgrades via **region-wide production cost model**
6. Develop guidelines to evaluate a **comprehensive set of cost savings and other benefits** when analyzing regional upgrades

III. Implement Comprehensive & Proactive Planning Process

7. Implement **multi-driver approach to identifying needs** and candidate solutions
8. Estimate cost savings and other benefits of solutions **over the entire useful life of the assets**
9. Establish regional cost allocation that reflects **beneficiaries pays and cost causation principles**

Order 1920 compliance offers opportunities to improve Southeast transmission planning processes beyond the Order's mandated minimum requirements

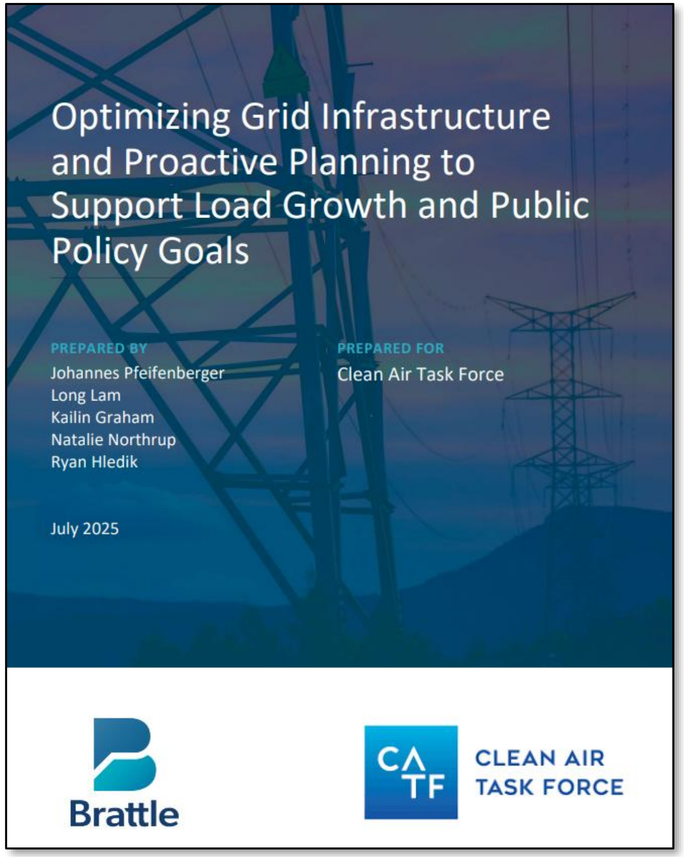
Significant Barriers to Planning New Transmission

A. Leadership, Alignment and Understanding	1. **Insufficient leadership from state & federal policy makers to prioritize creating effective regional and interregional planning processes** 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

Order 1920 (items 6–9)

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.

How to Support Load Growth and Policy Goals Quickly and Efficiently


Optimizing Grid Infrastructure and Proactive Planning to Support Load Growth and Public Policy Goals

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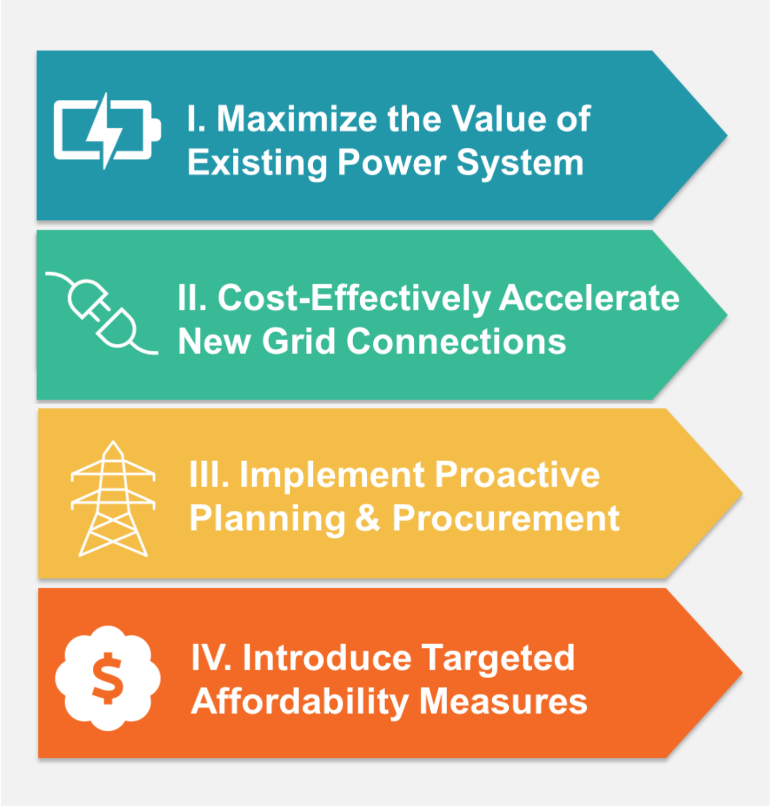
PREPARED FOR
Clean Air Task Force

July 2025

Brattle
CLEAN AIR TASK FORCE

Four Pillars to Supporting Load Growth



<u>Transmission-Related Recommendations</u>

I.C Utilize GETs, ATTs, and RASs
I.D Capitalize on grid upsizing opportunities

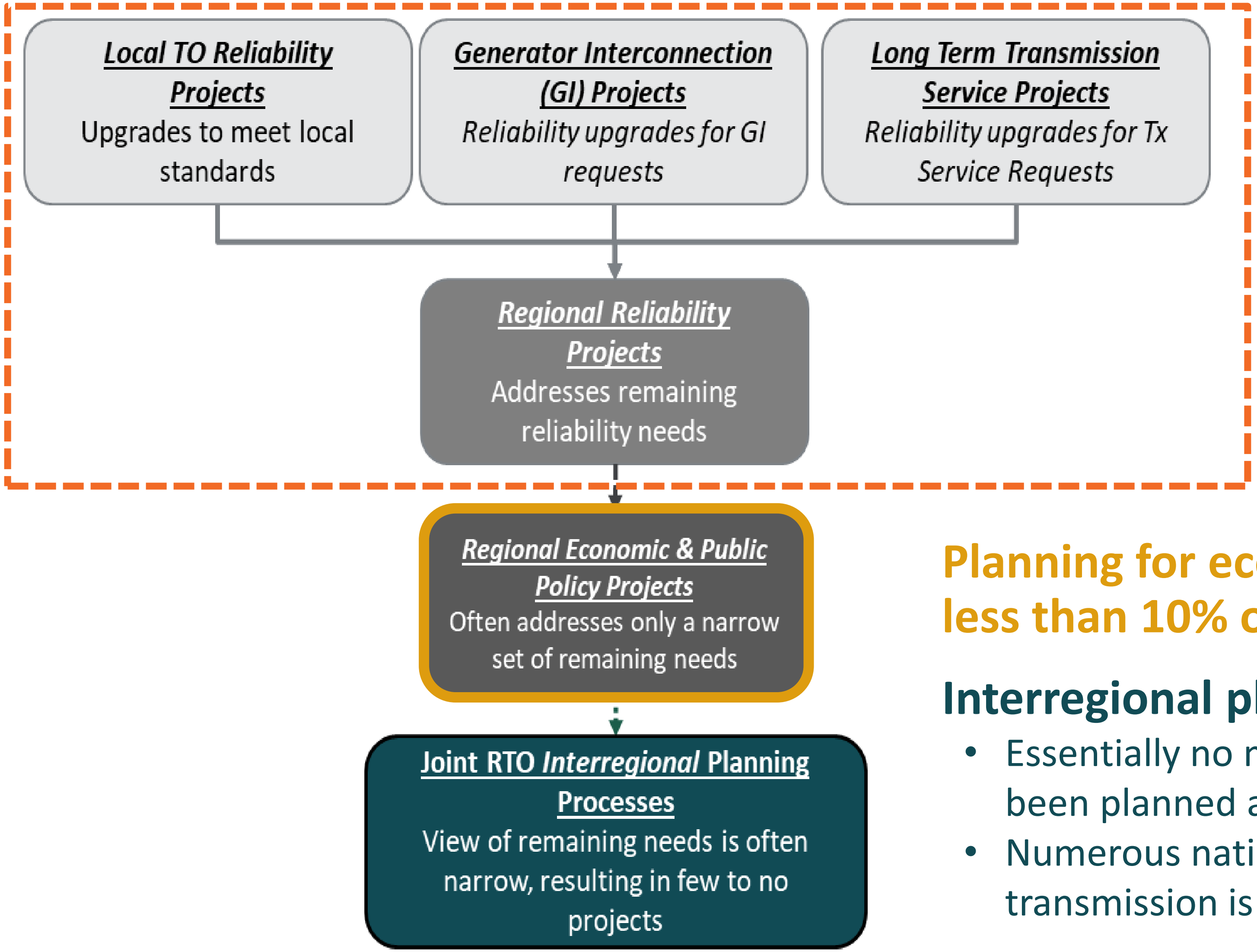
II.B Co-locate new generation and load
II.C Streamline gen interconnection processes

III.A Proactively plan gen and transmission
III.D Improve load interconnection processes

For each of these key areas, the report offers case studies, cross references to industry experience and commercially-available technologies, and a discussion of best practices.

Appendix Slides

Transmission Planning is Siloed and Reliability-Focused



Reliability-driven processes account for >90% of transmission investments

- None involve assessments of cost savings offered by new transmission
- Generator interconnection projects are a primary tool to support upgrades, delaying entry and demonstrating lack of transmission planning

Planning for economic & public-policy needs results in less than 10% of all U.S. transmission investments

Interregional planning processes are ineffective

- Essentially no major interregional transmission projects have been planned and built in the last decade
- Numerous national studies show that more interregional transmission is needed to reduce total system costs

See: DeLosa, Pfeifenberger, Joskow, Regulation of Access, Pricing, and Planning of High Voltage Transmission in the US, MIT-CEEPR, March 7, 2024.

Regulators Objectives Include Both Reliability and Affordability

- "Safe, adequate, reliable service at equitable and economical rate"
- "Safe, adequate and reliable utility services at just and reasonable rates"
- "Efficient provision of safe and reliable utility services at fair prices"
- "Safe, reliable, reasonably priced service for consumers"
- "Safe, adequate, reliable service at just and reasonable rates"
- "Just and reasonable rates and services of public utilities"
- "Safe and reliable utility service at reasonable prices, while supporting jurisdictional utilities' financial stability through fair and just rates and operational oversight"
- "Adequate, reliable, and economical utility service…least cost energy planning…just and reasonable rates and charges for public utility services"
- "Safe, reliable, reasonably priced telecommunications, electric, and natural gas service"

State Regulators are the Key to Advancing Transmission Planning

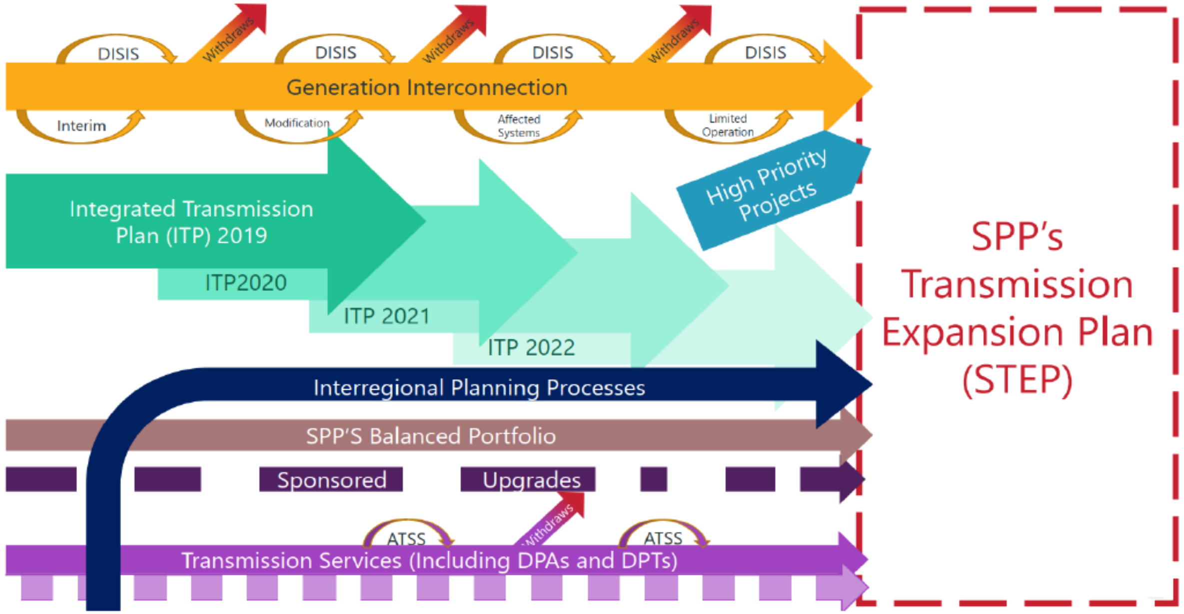
Most long-term, multi-value transmission planning processes across the country came at the request or significant involvement of state policymakers

- RSC in SPP and OMS in MISO: Both highly involved with early development of proactive planning in these regions to reduce congestion and access low-cost resources on their system
- NY Public Service Commission:
- North Carolina Utilities Commission:
- New England States

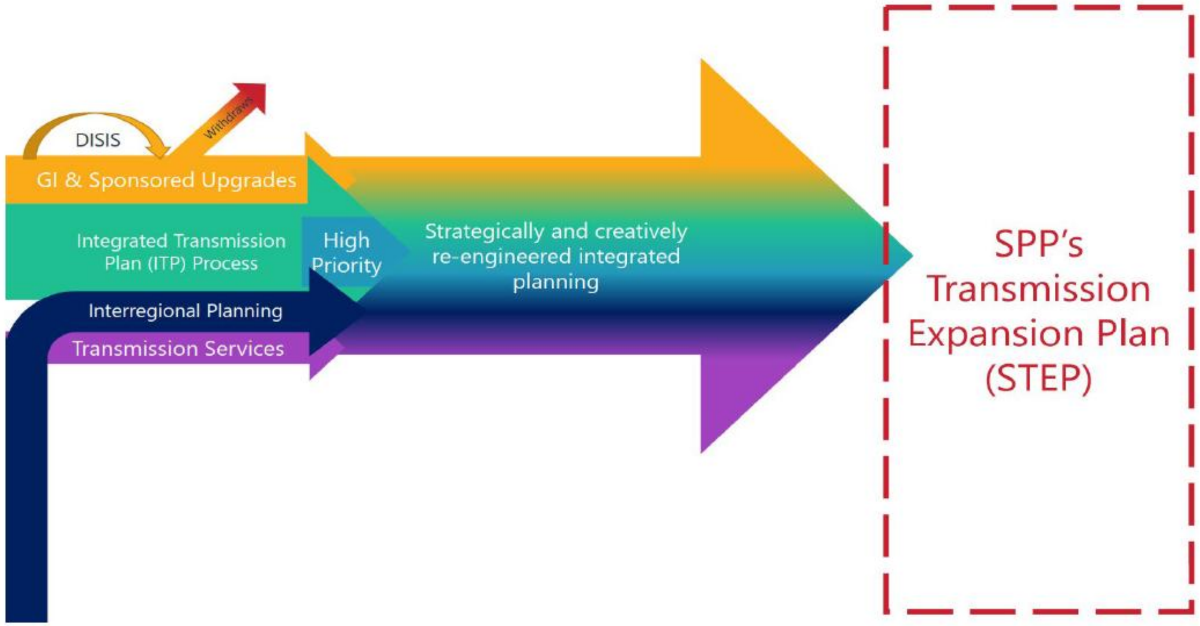
SPP's proposed Consolidated Planning Process (CPP)

The Southwest Power Pool (SPP) is working on consolidating siloed planning processes (e.g., for generator interconnection, regional transmission, transmission service requests, and interregional planning) into a single comprehensive process:

Current Planning Process

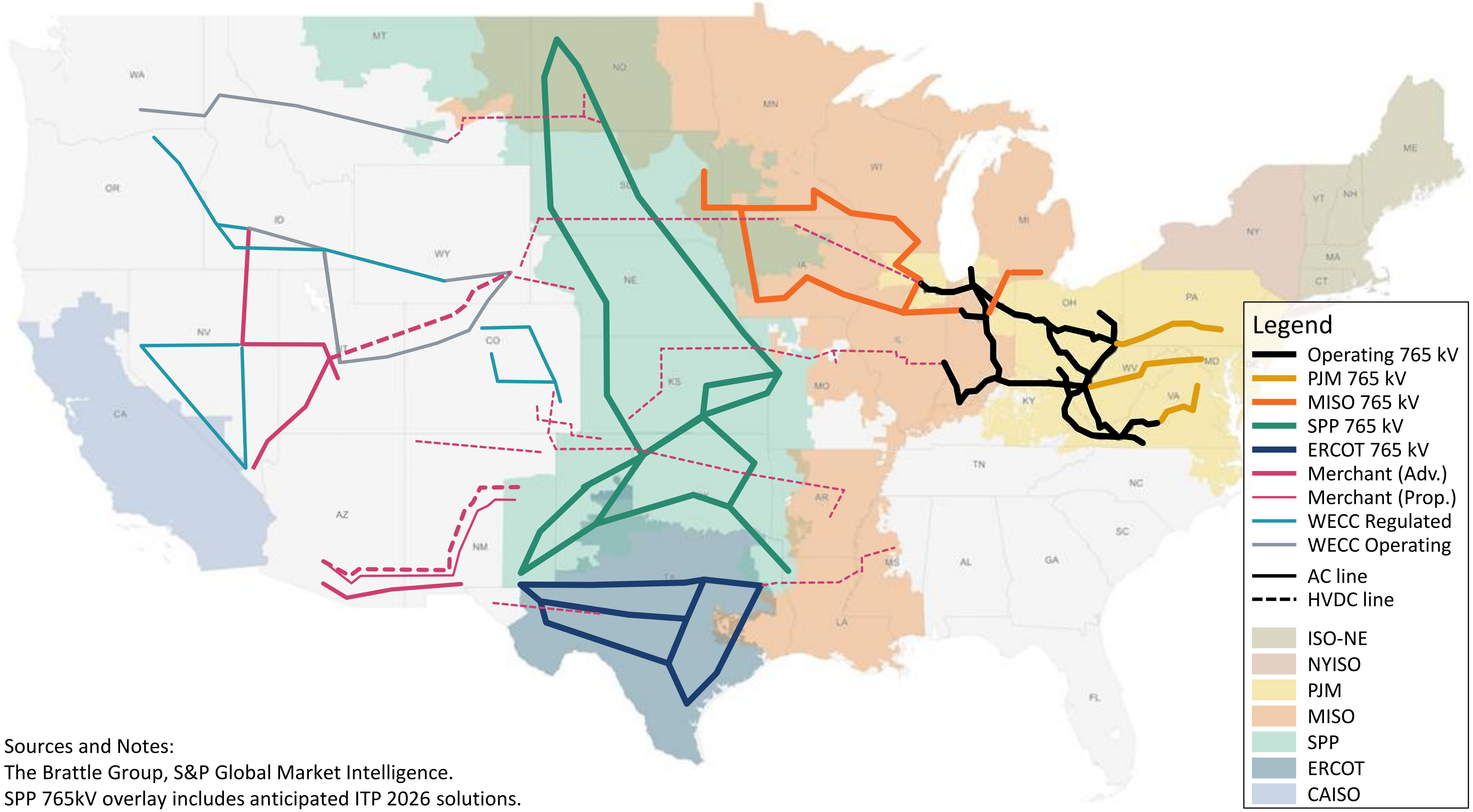


Proposed Consolidated Planning Process



Source: SPP, Strategic and Creative Re-Engineering of Integrated Planning Team (SCRIPT), CPP Task Force, Dec 13, 2021

Planners are Advancing 765 kV and HVDC Lines Across the U.S.



Sources and Notes:
The Brattle Group, S&P Global Market Intelligence.
SPP 765kV overlay includes anticipated ITP 2026 solutions.

765 kV lines planned by PJM, MISO, SPP, and ERCOT are adjacent to each other

- Could be planned to be connected, which would create an interregional Macro Grid
- Should also be integrated with HVDC lines, including into ERCOT and WECC

Proven practices for quantifying cost savings of transmission

Regional and local planners should take advantage of proven practices

- See our report with Grid Strategies for a summary of quantification practices, incl. benefits beyond Order 1920's mandated ones

Most recent developments:

- Use weather-reflective (rather than weather-normalized) production cost and long-term expansion planning simulations (e.g., for 20-30 weather years)
- Production cost simulations with both day-ahead and real-time cycles to capture unpredictable real-time challenges and associated transmission value

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

FERC’s Order 1920 Leaves Room for Improvements

Order 1920 compliance offers opportunities to improve transmission planning processes beyond the Order’s mandated minimum requirements:

1. Better deal with long-term uncertainties through proactive, **scenario-based planning**
2. Use best-practice experience for comprehensive benefit quantification (beyond 7 benefits and understated quantification)
3. Consolidate siloed (near- and long-term) planning processes
4. Employ **least-regrets** planning criteria to minimize the risk of both over-building and under-sizing
5. Develop more **flexible** solutions
6. Get more out of the existing grid, focus on cost effectiveness, and include cost-control incentives
7. Explicitly consider interregional solutions to regional needs

Key planning tools for an uncertain future (beyond transmission):

- Scenario based
- Flexible, least-regrets solutions

For more detail, see Integrated System Planning under Uncertainty, September 23, 2025; and