Interregional Transmission and Benefits from Improved Planning

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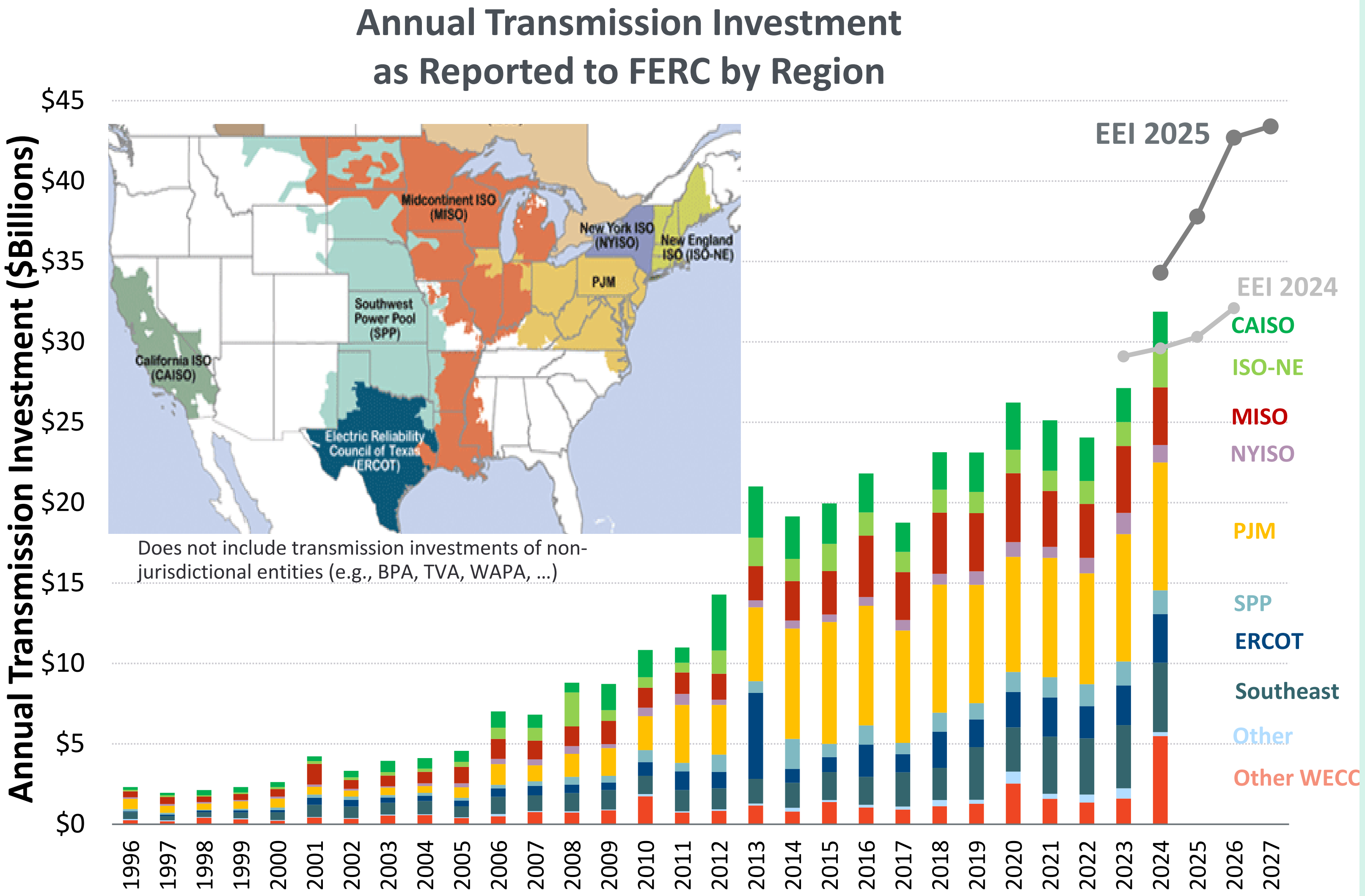
MGA

America's Smartland

Midwestern Governors Association

Topics discussed today

Annual U.S. Transmission Investments 1996-2024



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

Total US transmission investment has increased from $3 to $30 billion in the last 30 years!

- About 90% of it is justified solely based on reliability needs (without benefit-cost analysis)
- About 50% based on “local” utility criteria (aging assets; without going through regional planning processes)
- Other than in MISO, very few projects are justified based on multi-driver planning in other regions
- **Essentially no interregional transmission is being planned (other than by merchant developers)**

Transmission planning is too siloed and reliability-focused

Local TO Reliability Projects
Upgrades to meet local standards

Generator Interconnection (GI) Projects
Reliability upgrades for GI requests

Long Term Transmission Service Projects
Reliability upgrades for Tx Service Requests

Regional Reliability Projects
Addresses remaining reliability needs

Regional Economic & Public Policy Projects
Often addresses only a narrow set of remaining needs

Joint RTO *Interregional* Planning Processes
View of remaining needs is often narrow, resulting in few to no projects

More consolidated, comprehensive, proactive planning is needed to achieve cost-effective planning outcomes

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

- None involve any assessments of economic benefits (i.e., cost savings offered by the new transmission)

Incremental generation interconnection has become the primary tool (and efficiency barrier) to support public policy goals

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

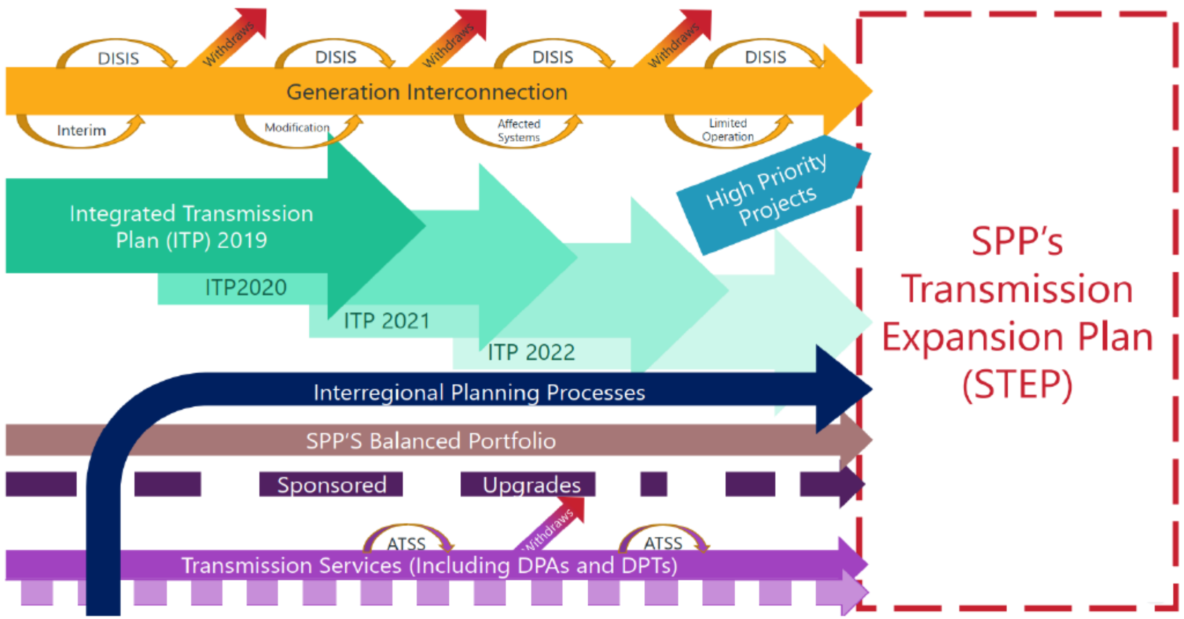
Interregional planning processes are large ineffective

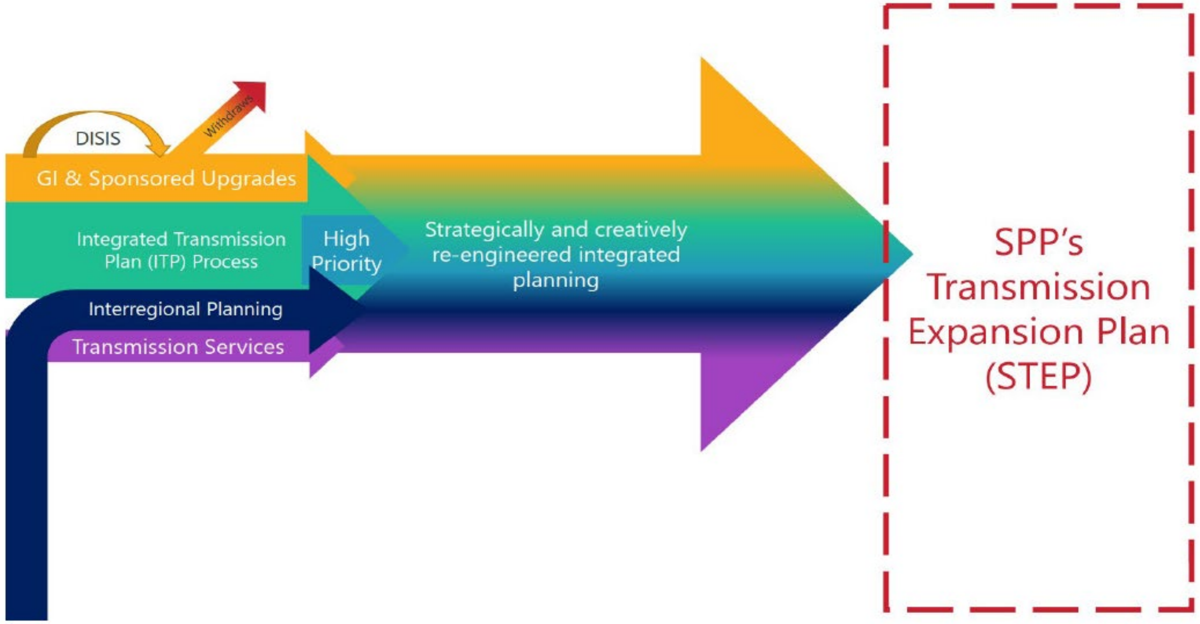
- Essentially no major interregional transmission projects have been planned and built in the last decade
- Numerous national studies show that more interregional transmission is needed to reduce total system costs

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

Example: SPP's proposed Consolidated Planning Process (CPP)

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





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

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

"Transmission Benefits" – what are they?

Multi-value transmission planning allows the selection of transmission solutions that offer the greatest net benefits

- But what are these (often abstract) "transmission benefits"?

Transmission benefits = Cost savings (or better reliability) offered by the upgrade

Examples of savings from right-sized, multi-value transmission investments:

- Enable lower-cost generation to displace higher-cost generation = production cost savings
- Reduce need for reserve capacity through geographic diversification = investment cost savings
- Avoid costs of other transmission upgrades or refurbishments = investment cost savings
- Allow generation construction in lower-cost areas/regions = investment cost savings
  (Note: this is not in Order 1920 list of seven required benefit metrics)

Studies show: if planned well, every $1 billion spent on transmission saves $2-3 billion

Bottom line: Sometimes you have to spend money to safe money!

Well-documented: proven practices for quantifying a broad set of transmission benefits

Take advantage of proven practices (as referenced in Order 1920)

- 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

Benefits Example: Production Cost Savings

Production cost savings = fuel and operating cost savings from better utilizing the existing and projected future generation fleet

- Tools typically used to estimate: Nodal "production cost" (market simulation) models
- **Simulations tend to understate production-cost savings** (by 40% or more) because they:
  1. Only simulate **normal weather and loads** (i.e., no heat waves, cold snaps, or extreme weather)
     LBNL: 50% of savings come from 5-10% of the most challenging hours in a decade (more interregionally)
  2. Only assume **normal fuel prices** (e.g., no spikes in gas prices or basis differentials)
     Example: Current polar vortex weather increased Henry Hub prices to $5/MMBtu but Boston gas prices to $25/MMBtu
  3. Do not usually simulate operations during **transmission outages or unusual generation outages**
     Example: 60+GW gen outages during winter storms Uri/Elliot; considering transmission outages increases savings by 10-20%
  4. Assume **perfect foresight** of all real-time market conditions
     LBNL: most transmission-related savings in 5-10% of the most challenging hours are not foreseeable on a day-ahead basis
     BU Study: transmission benefits much higher when uncertainties are considered in simulations
- **What's missed by typical production cost simulations can and should be quantified**
  – Only parts of 1 and 3 (extreme weather, transmission outages) are explicitly required by Order 1920
  – See Brattle report with Grid Strategies

Benefits Example: Generation Investment Cost Savings

- **Resource adequacy benefits** = lower reserve margins <u>or</u> higher reliability
  - Diversifying loads and resources reducing the necessary planning reserve margins and installed generation capacity needs (by sharing reserve capacity across larger footprint)
    - Larger footprint = larger diversification savings = interregional T offers larger benefits
    - Highest benefits by creating footprints that are greater than the weather
  - <u>Note</u>: a region with adequate reserve margin may (a) initially benefit from higher reliability and (b) achieve capacity cost savings once the enabled lower reserve margin reduces generation investments
- **Other generation cost savings**: transmission that allows for additional generation development in lower-cost regions/areas
  - Access areas with lower land/construction costs (particularly relative to locations near load centers)
  - Access to areas with lower fuel costs (e.g., mine-mouth coal plants built in 1970s)
  - Create access to areas with hydro potential or with higher wind/solar capacity factors (to generate more MWh for every MW built) (e.g., Texas CREZ)
  - <u>Note</u>: this is <u>not</u> one of Order 1920’s required list of seven benefits

Benefits Example: Avoided Transmission Costs

- Planning proactively for multiple future transmission needs creates more holistic **solutions that avoid (or defer) piecemeal/incremental transmission upgrades** that would be approved through planning for only one transmission need at a time
  - Upgrades that capture cost savings in addition to meeting reliability requirements set out in NERC transmission planning standards avoid the reliability-only upgrades that would have to be made otherwise.
- Example: reliability need requires replacing aging 230kV line for $800 million
  - Replacing the aging existing line with an (upsized) 345kV line instead may costs $1 billion but offers:
    - An additional 1 GW of added transfer capability
    - Congestion relief and associated production cost savings
    - Additional headroom for load and generation interconnection
  - In addition to these benefits, the upsized $1 billion 345kV solution **avoids other transmission costs**:
    - The known $800 million in-kind reliability upgrade (now or in the future) ➔ added T cost is only $200 million
    - Likely additional future reliability upgrades (typically not yet identified)

Scenario-based planning: Explicitly recognize an uncertain future

Scenario-based planning is a process first developed in the 1940s and 1950s as a tool for integrating uncertainties into long-term strategic planning:

- Used by Shell with great success since the 1970s for long-term planning under large uncertainties
- **Allows planners to think, in advance, about the many ways the future may unfold and how to respond effectively and flexibly as uncertain future outcomes become reality**
- Ranks among the top-ten management tools in the world today*
- Scenario = one fully-defined, plausible view of what the future may look like

This type of scenario-based planning is a multi-step process:

1. Define scenarios of plausible futures by scanning the current reality, trends and forecasts, uncertainties, and important internal and external drivers
2. Develop a series of plans (initiatives, projects, policies, tactics) that work well across multiple scenarios (e.g., by developing **solutions that are flexible and robust across all plausible futures**)
3. Implement preferred plan and define indicators to alert planners that a certain future is likely to occur, so they can take action (e.g., exercise options to address the new developments)

*See Living in the Futures (hbr.org) and Scenario Planning-A Review of the Literature.PDF (mit.edu)

How can risks be mitigated through “least-regrets” planning?

The concept of “least-regrets” planning is widely popular but poorly understood. What is it?

Should least-regrets planning identify resource and grid plans that offer:

1. The lowest transmission cost for the chosen “reference/base-case” scenario (least-cost planning)?
2. The lowest total system costs (G+T+reliability costs) for the reference/base-case scenario?
3. Investments needed only for the least challenging scenario (to avoid building too much)?
4. Sufficient capacity to handle even the most challenging scenario (to avoid being “caught short”)?
5. The lowest average cost (highest average benefits) across all scenarios (i.e., best probability-weighted outcome)?
6. The lowest “cost of being wrong” across all scenarios (i.e., minimize risk)?
7. The best combination of (5) and (6)?

This is what least-regrets planning should focus on!

Example: AEMO least-regrets framework used in its Integrated System Plan (ISP)

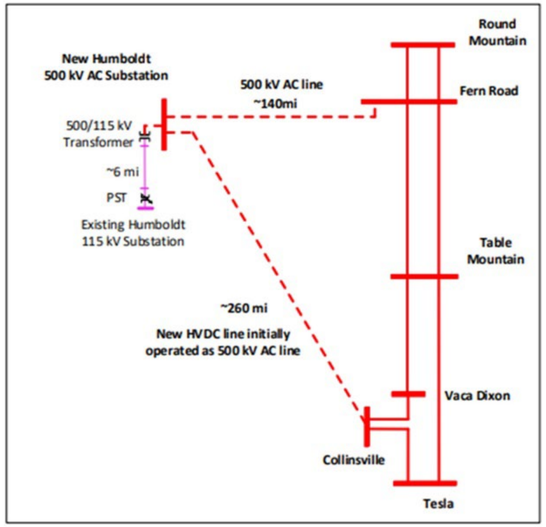
Examples: Flexible solutions to reduce costs and minimize regrets

Planning processes need to develop more flexible (lower-regret) generation and grid solutions that create valuable options, given high long-term uncertainties:

- Example 1 – rebuild aging single-circuit 230kV line as 345kV-ready with double-circuit towers to create option to: (1) initially operate circuit at 230kV, (2) later add 1 GW of transfer capability by stepping it up to 345kV (with transformation), and (3) if needed, expand the capacity by adding a second circuit
- Example 2 – CAISO's expandable offshore-wind integration solution with HVDC-ready 500kV line:

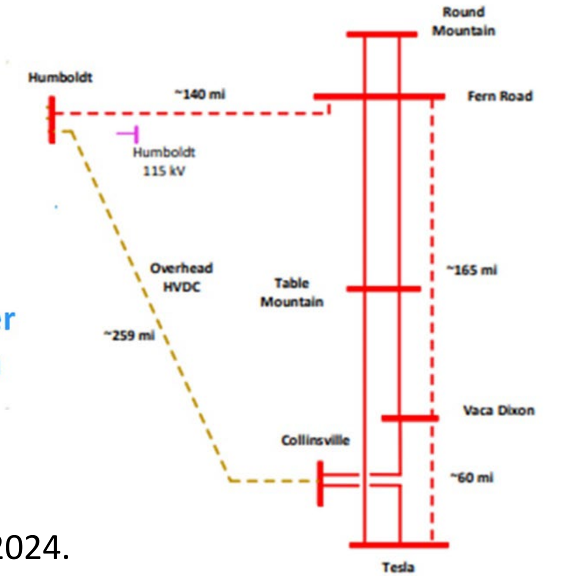
Two new 500kV lines, of which one is "HVDC-ready"

Phase 1: Base Case Plan
(1,607 MW)



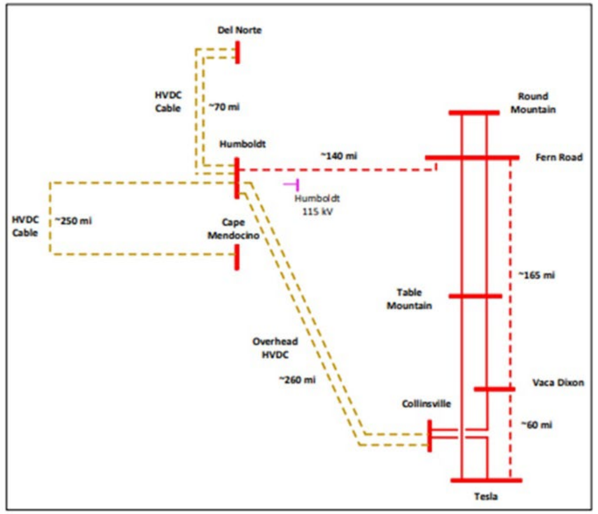
Add DC converter stations to each end of the line

Phase 2: DC Conversion
(3,100 – 3,300 MW?)



Add a second HVDC line

Phase 3: Expanded Plan (Option B)
(8,045 MW)

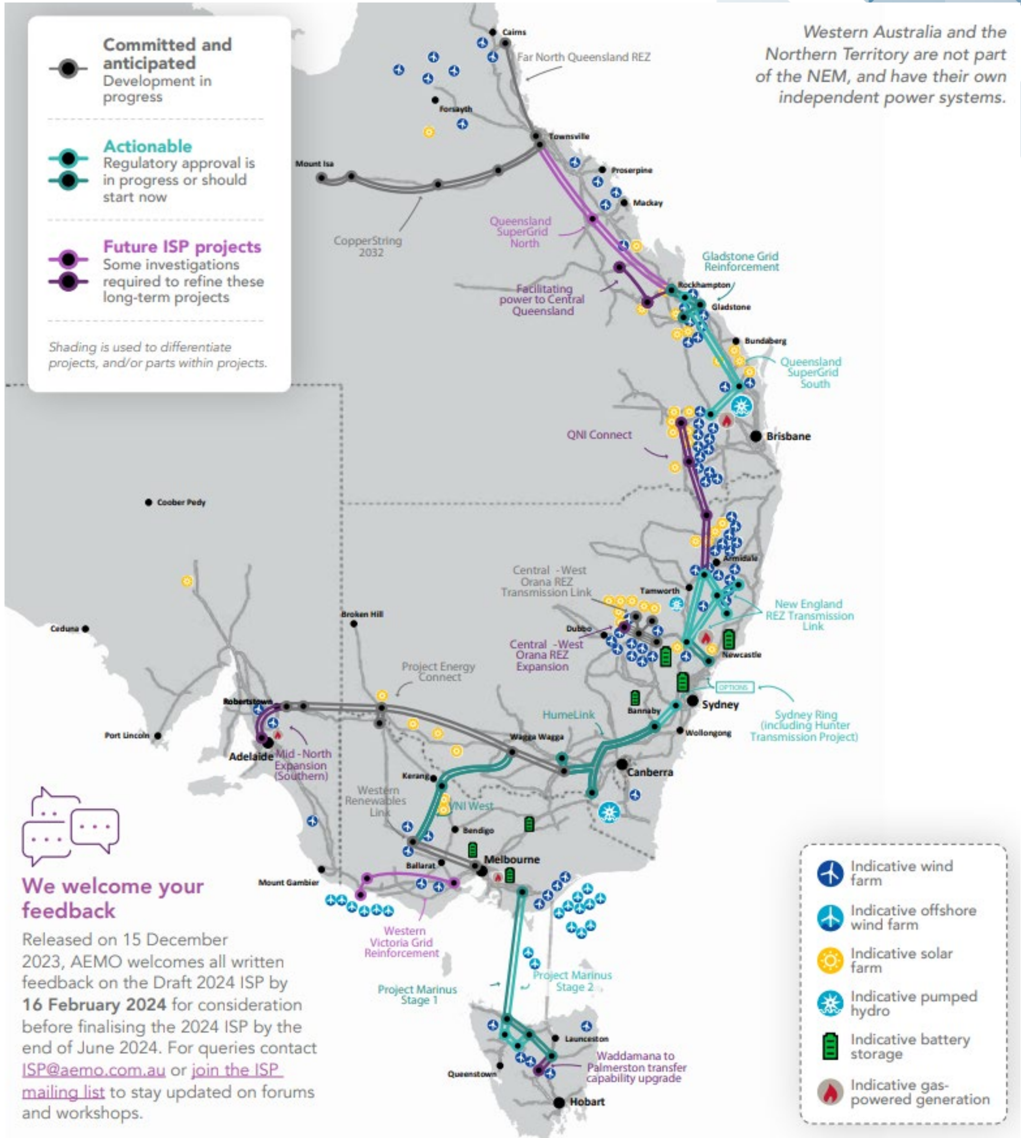


Source: CAISO-2023-2024-transmission-plan, May 23, 2024.

Example: Australian Integrated System Plan (ISP)

The Australian Energy Market Operator (AEMO) integrated planning process is "best in class" for proactive, scenario-based, least-regrets planning:

- **Clearly-specified but flexible** methodology (link) produces updated plans every two years with extensive stakeholder consultations (see Draft 2024 ISP)
  - **Scenario-based** analysis explicitly considers long-term uncertainties and risk mitigation over next 30 years (link)
  - **Least regrets** planning values optionality that can be exercised if/when needed (e.g., projects that can be built/expanded in stages; or undertaking "early works" to develop shovel-ready projects that can be constructed quickly in the future)
  - **Both near- and longer-term needs:** (1) actionable projects for which the need is certain enough now to move forward; and (2) future projects that are likely needed at some point
- **Guidelines** for cost-benefit framework, forecasting, and "investment tests" from the Australian Energy Regulator (AER) make AEMO plans actionable (link)



Source: AEMO | Draft 2024 ISP Consultation

Why interregional transmission and what's holding us back?

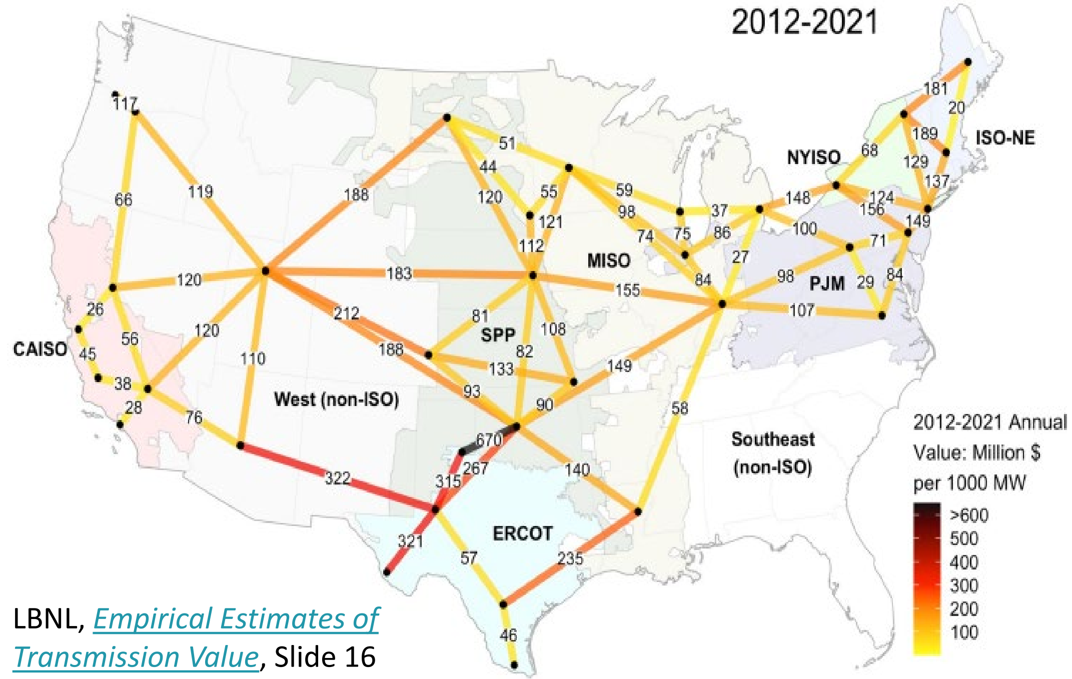
Q: Why interregional transmission?   A: It is uniquely beneficial

- Larger geographic footprint offers more substantial diversity-related economic and reliability value
  - Capturing full (load and resource) diversity value requires a grid that is larger than the weather
- Peak-load and resource availability diversity = reduced regional resource adequacy requirements
- Temporary lower-cost/surplus generation in a region can be be shared across larger footprint
- Larger scale of interregional solutions can be more cost effective than multiple regional solutions

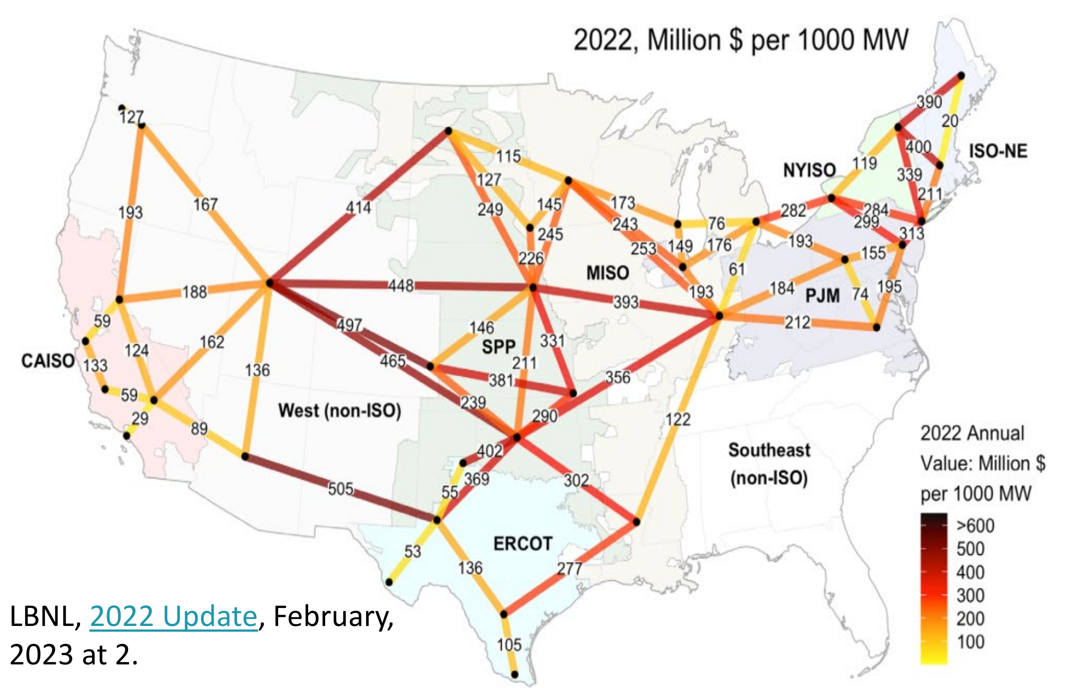
Q: Why don't we see much of it getting planned? A: Many barriers (slide 21)

- No defined interregional reliability standards or planning requirements
- Each region prefers meeting its reliability needs on its own
- Largely ignored in RTOs' regional multi-value planning processes
- Addressing local needs before regional, and regional needs before interregional, pre-empts more cost-effective interregional opportunities
- ISOs prefer to avoid the added complexity of multi-regional coordination and cost allocation
- <u>Result</u>: only merchant transmission developers have been proposing major new interregional projects

LBNL: High Value of Interregional Transmission (2012-2022)



LBNL, [Empirical Estimates of Transmission Value](), Slide 16



LBNL, [2022 Update](), February, 2023 at 2.

Sources: *[LBNL, Empirical Estimates of Tx. Value]()* *(Aug 2022), Slide 16;* *[The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade]()*, *Fact Sheet, LBNL (Feb 2023) at 2.*

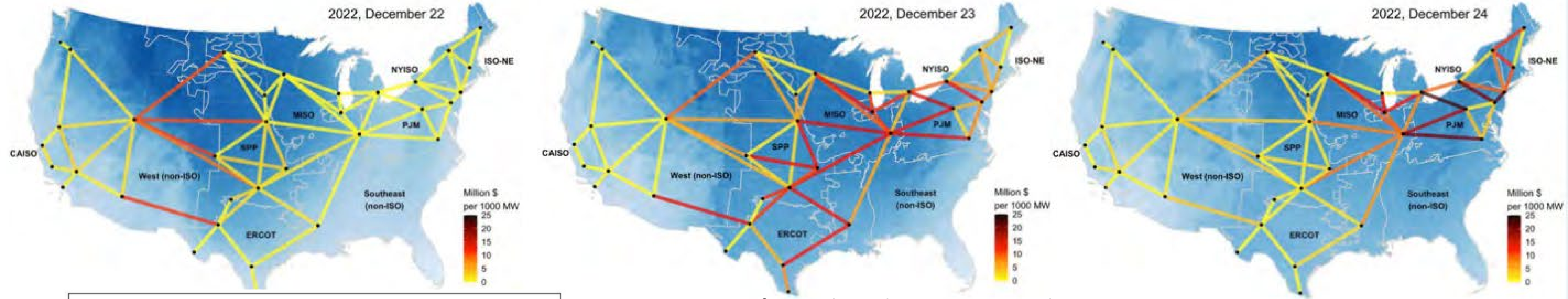
Methodology: Transmission value based on historical real-time price difference between regional nodes

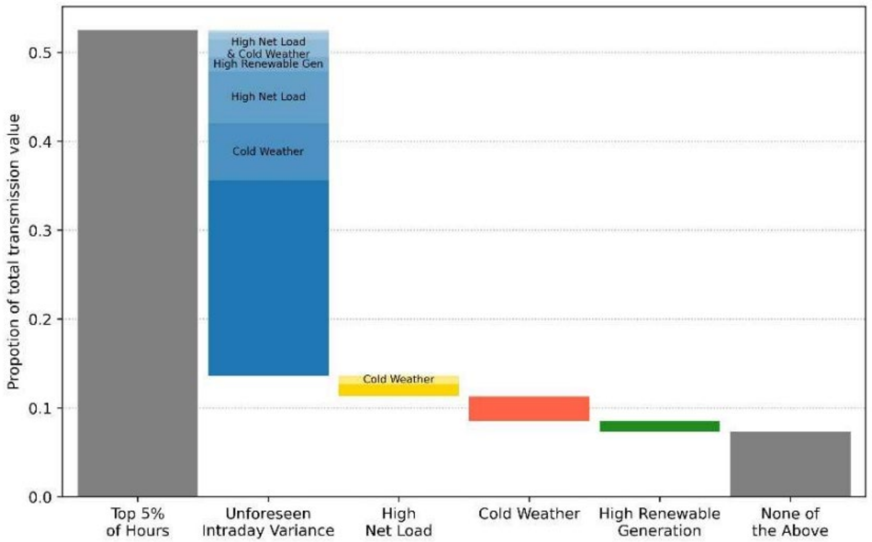
Study Findings:

- Interregional links have greater value than regional links
- The value in some of the recent years (e.g., 2021, 2022) is double the 10-year average
- Insurance against extremes: 40-80% of transmission value occurs in top 5% of hours due to challenging system conditions; <u>20-30% from top 1% of hours</u> reflecting the high impact of extreme conditions

Value of interregional transmission during challenging events

Interregional transmission is highly valuable, during challenging and extreme events.
Example: three days of **Winterstorm Elliot** (2022)



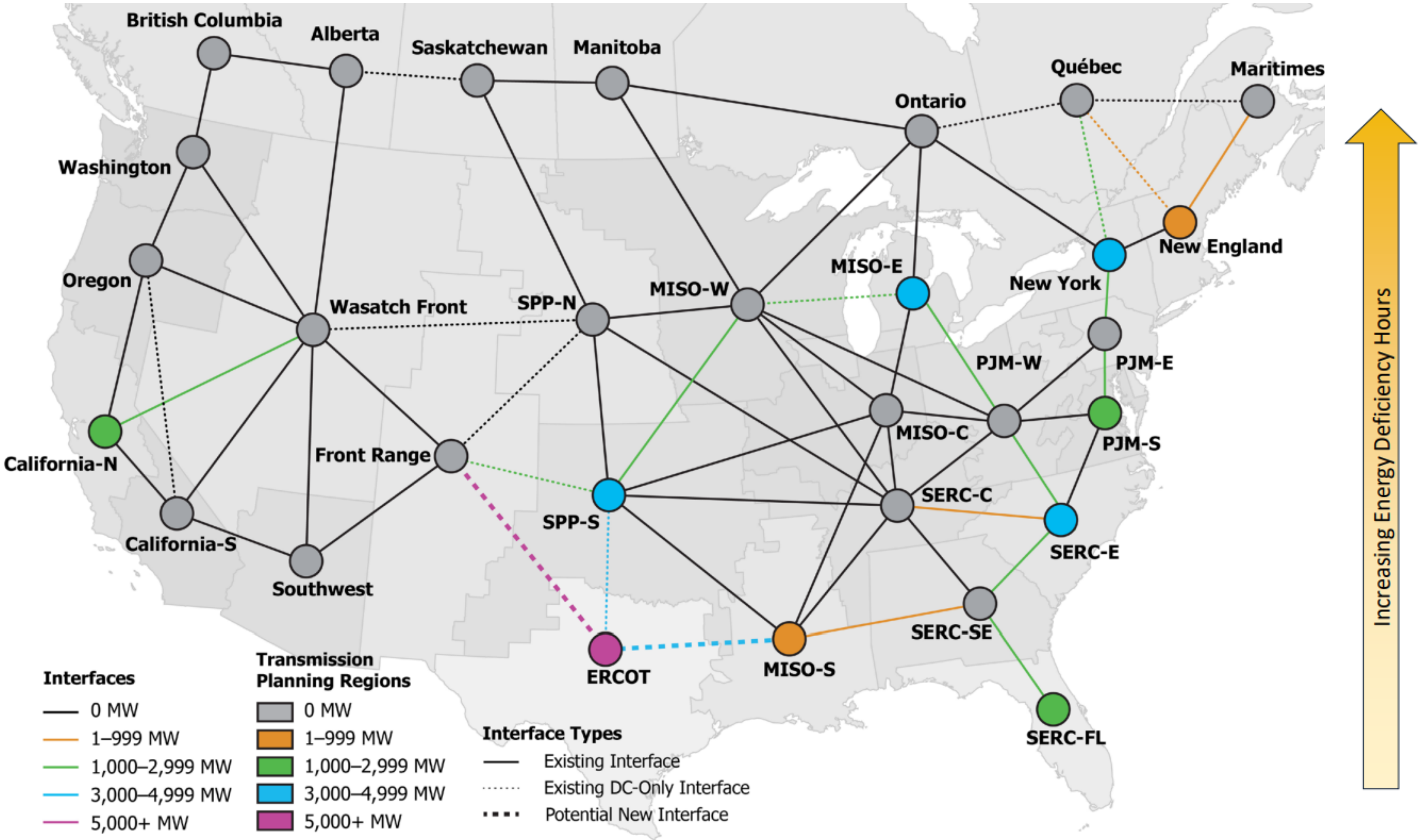


Findings of multiple national studies:

- **Benefits are estimated to exceed costs of transmission expansion**
- LBNL: Most of that value is concentrated in top 5-10% of hours and due to unpredictable real-time market conditions that are not foreseeable even on a day-ahead basis

Sources: LBNL, Transmission Value Manuscript NatureEnergy (March 29, 2024); Department of Energy's 2023 National Transmission Needs Study (Oct 2023)

NERC ITCS: "Prudent" Expansions by 2033 (reliability only)



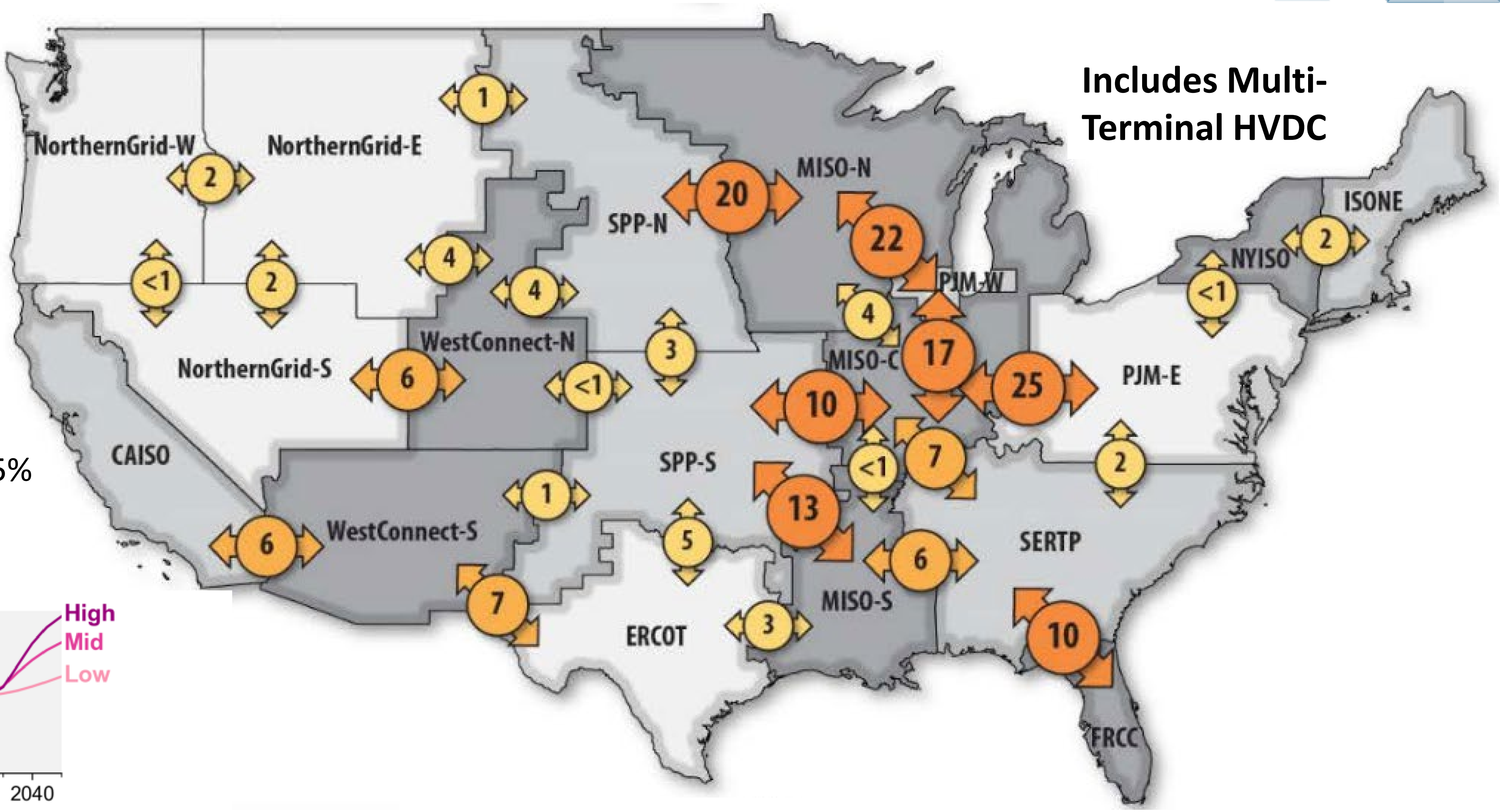
Transmission Planning Region	Additional Transfer Capability (MW)	Interface Additions (MW)
ERCOT	14,100	Front Range (5,700) MISO-S (4,300) SPP-S (4,100)
MISO-E	3,000	MISO-W (2,000) PJM-W (1,000)
New York	3,700	PJM-E (1,800) Québec (1,900)
SPP-S	3,700	Front Range (1,200) ERCOT (800) MISO-W (1,700)
PJM-S	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)

DOE National Transmission Planning Study (NTPS)

GW of "High-opportunity" interregional transmission expansion, beneficial by 2035

(Based on "central" case; beneficial in 75% of all scenarios evaluated)



Includes Multi-Terminal HVDC

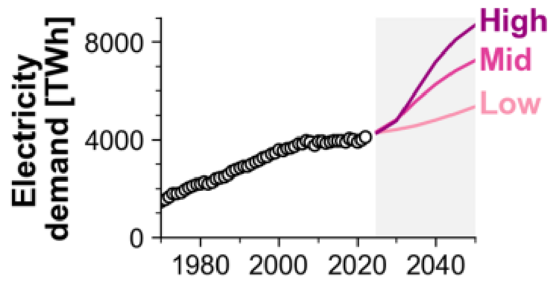


Figure 5. Annual demand assumptions for the contiguous United States

Historical demand shown is electricity sales to ultimate customers from EIA (2024b).

Source: DOE National Transmission Planning Study (Chapter 2, p. 47)

Limitations of National Studies

Although existing many studies demonstrate the benefits of transmission expansion, they have not been successful motivating actual transmission project developments. The reasons include some or all of the following:

- Some studies **analyze aspirational targets or scenarios that do not reflect the actual policies and mandates** applicable for the next 10-15 years
  - This makes it difficult demonstrate a compelling “need” to policy makers, regulators, and permitting agencies
- The studies are **not transmission planning studies**: they often do not identify specific transmission projects and do not connect with RTO planning processes and needs identification
- Studies **do not 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 broad support and develop feasible cost allocations
  - The studies typically do not consider or propose how to recover (“allocate”) transmission costs
- There has not been **an analysis of the state-by-state economic impact and job creation** from interregional transmission development, reduction in electricity prices, and shifts in the locations of clean-energy investment
- Most studies do not address the many barriers to planning processes and to the permitting/development of specific interregional transmission projects

Reminder: Significant Barriers to Interregional Transmission

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 (often too contentious or overly formulaic)
C. Regulatory Constraints	10. Overly-prescriptive tariffs and joint operating agreements 11. State need certification, permitting, and siting

Source: The Brattle Group. 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.

Seams currently prevent efficient use of interregional transmission

Significant seams-related inefficiencies exist between RTO markets (and other regions) that prevent us from effectively planning and taking full advantage of (existing and new) interregional transmission infrastructure:

1. **Interregional transmission planning** is mostly ineffective
2. **Generator interconnection** delays and cost uncertainty created by affected-system impact studies (and effectiveness coordination through means such as the SPP-MISO JTIQ, reducing costs by 50%)
3. **Loop flow management** inefficiencies through market-to-market coordinated flowgates (with shares of firm flow entitlements) under the existing JOAs
4. **Inefficient trading** across contract-path market seams and the need for intertie optimization*
5. **Resource adequacy** value of interties (often not considered in RTO's resource adequacy evaluations) and barriers to capacity trades (often created by RTOs' restrictive capacity import requirements and incompatible resource accreditations)**

*See Intertie Optimization: Achieving Efficient Use of Interregional Transmission, IEEE PES Energy and Policy Forum, April 2025.
** See How To Realize the Maximum Value of Interregional Transmission | NLR Report , June 2024.

Order 1920's enhances "Interregional Transmission Coordination"

As FERC's Explainer states: "Order No. 1920 requires transmission providers in neighboring transmission planning regions to modify their existing **interregional transmission coordination procedures** to align with long-term regional transmission planning reforms. Order No. 1920 established the following requirements to adapt existing procedures with this requirement.

1. Require transmission providers to share information regarding long-term transmission needs and **identify and jointly evaluate interregional transmission facilities** to address those needs
2. **Allow entities to propose** interregional transmission facilities as more efficient or cost-effective solutions to long-term transmission needs

Transmission providers are mandated to make the following information publicly available through their website or e-mail list to **enhance transparency and information sharing**.

1. Long-term transmission needs discussed in interregional transmission coordination meetings
2. Interregional transmission facilities proposed or identified as part of long-term regional transmission planning
3. Details such as voltage level, estimated cost, and estimated in-service date of proposed interregional transmission facilities
4. Results of cost-benefit evaluations for such interregional transmission facilities, including overall benefits and region-specific benefits
5. Selection of interregional transmission facilities to meet long-term transmission needs, if any

These reforms aim to ensure that identified long-term transmission needs are considered in interregional coordination and cost allocation processes, thereby promoting fair rates."

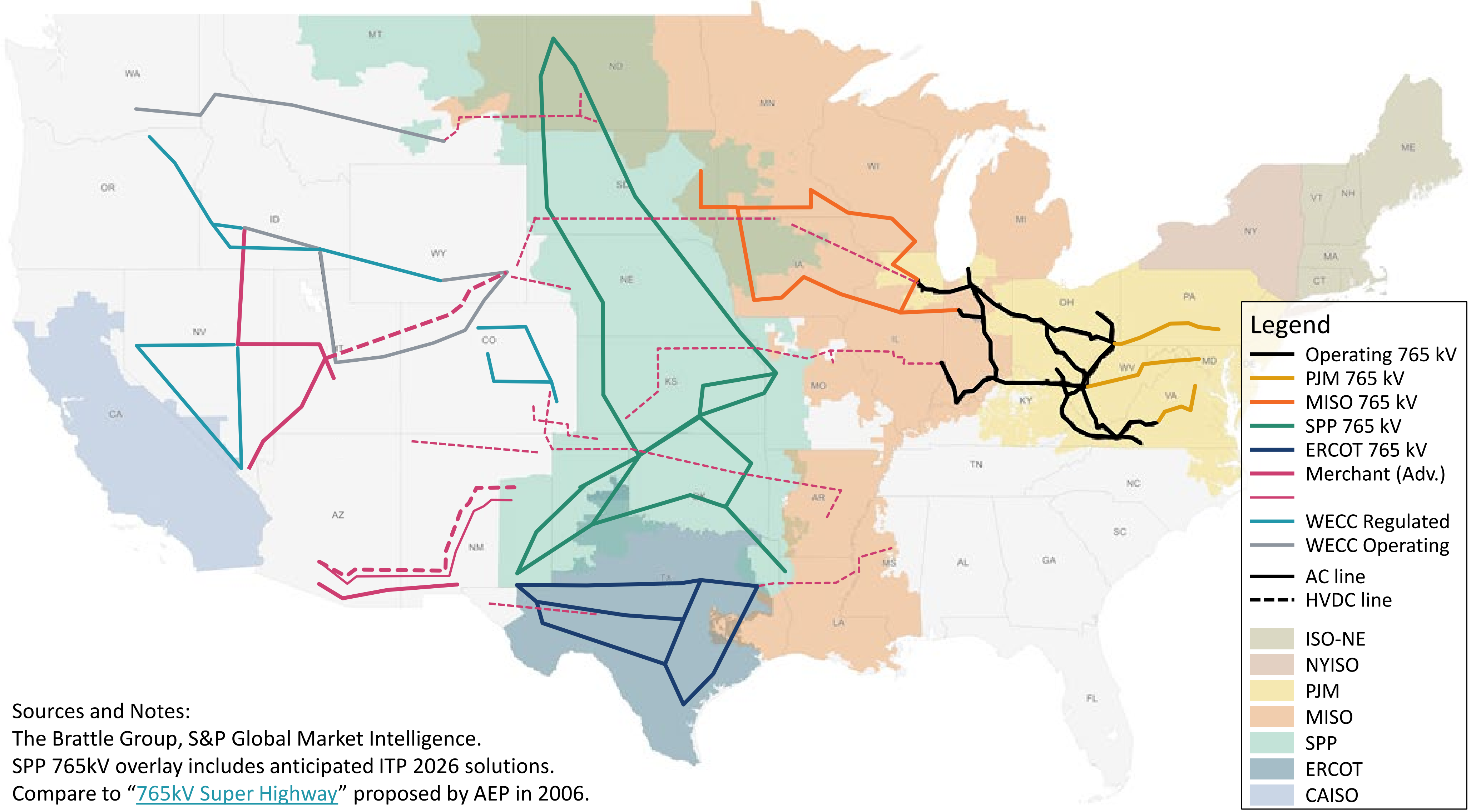
MISO-SPP JTIQ example: Lower-cost interregional solutions

MISO's and SPP's Joint Targeted Interconnection Queue (JTIQ) Study shows that proactively studying a larger interregional set of generator interconnection requests offers substantial cost savings

- Goal: Identify more comprehensive, cost-effective and efficient interregional network upgrades than could be found through the RTO's individual sequential interconnection queue and affected system coordination processes
  - Pooled GI requests for 5 (and 10) years in both regions near seam
- Result: Seven-project, **$1.65 billion JTIQ Portfolio** expected to fully address the transmission needs along the MISO-SPP seam previously identified in MISO and SPP individual generation interconnection studies
  - Able to support 9 GW of existing generator interconnection requests and enable an additional 20 GW of projects near the SPP-MISO seam
  - Additionally yields estimated $1 billion in production cost savings ($724 million in MISO and $247 million in SPP)
- JTIQ generator interconnection costs: **$58/kW** with 100% participant funding; and **$28/kW** if production cost savings to regional loads are netted
  - **Less than half of SPP's and MISO's individual GI costs of $100-130/kW!**

See MISO-SPP Joint Targeted Interconnection Queue Study (misoenergy.org); April 15, 2022, MISO-SPP JTIQ Presentation;
Tsuchida, Proactive Planning for Generation Interconnection A Case Study of SPP and MISO (August 17, 2022) at 9

There is hope: We may soon be half-way to a Macro Grid



Sources and Notes:
The Brattle Group, S&P Global Market Intelligence.
SPP 765kV overlay includes anticipated ITP 2026 solutions.
Compare to "765kV Super Highway" proposed by AEP in 2006.

The 765 kV systems planned by PJM, MISO, SPP, and ERCOT are adjacent to each other!

- They could (should?) be planned to be connected, which would create an interregional Macro Grid
- Then should also be integrated with HVDC lines, including into ERCOT and WECC

Thank You!

(Additional Slides)

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Mr. Pfeifenberger specializes in wholesale power markets and transmission. He has analyzed transmission needs, transmission benefits and costs, transmission cost allocations, and renewable generation interconnection 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, WECC, and Canada and has analyzed offshore-wind transmission challenges in New York, New England, and New Jersey.

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.

Transmission options for more cost-effective, affordable outcomes

Achieving cost-effective transmission-planning outcomes requires a multi-faceted approach:

1. More **proactive and comprehensive transmission planning** (as mandated by Order 1920)
   - Multi-driver/value planning (incl. for generator interconnection) to find lowest-total-cost solutions
   - Least regrets planning to mitigate risk and costs of both overbuilding and undersizing
2. "**Loading order**" for transmission planning that prioritizes lower cost/impact options
   - Optimize existing grid → upsize existing lines → add new lines
3. **Cost control incentives**
   - Soft/hard cost caps, broad-based PBR, or targeted incentives (such as shared savings/overruns)
4. **Competitive solicitations**
   - Where possible and practical; with added cost-control incentives
5. **End-use efficiency and demand flexibility**
   - To reduce transmission, distribution, generation, and resource-adequacy costs

(See our NESCO slides: Ensuring Cost-Effective Transmission in Support of a Clean Energy Transition, Aug 2024)

We need to double or triple US transmission capability … and can do at least some of it quickly and cost-effectively!

1. Advanced, grid enhancing technologies

- Dynamic line ratings
- Flow control devices
- Topology optimization
- Grid-optimized DER/storage
- Remedial action schemes
- Grid-forming inverters

2. Upgrades of existing lines

- Advanced conductors
- Rebuild aging lines at higher voltage
- Conversions to HVDC

3. New transmission

- Highway/railroad corridors
- ROW-efficient AC designs
- HVDC transmission
- Submarine/undergound
- New greenfield overhead

Examples:

Priority order required by the German "NOVA Principle"

MA CETWG Report: "Loading Order" and ATT/GETs recommendations

Options for interconnecting generation more quickly and efficiently

With FERC Order 2023 guidance and emerging best practices from other regions, the following measures can add resources more quickly and cost-effectively:

1. Implement fast-track process for sharing and transfers of existing POIs
2. Identify existing "headroom" at possible POIs
3. Fast-track new POIs for "first-ready" projects
4. Allow for GETs and (simple) RAS/SPS to address interconnection needs
5. Simplify ERIS (energy-only) interconnections with option to upgrade to NRIS (capacity) later
6. Proactively and holistically plan for long-term transmission needs
7. Speed up state & local permitting for projects with signed interconnection service agreements (PJM blog: 44+ GW with ISAs yet only 2 GW brought online in 2022)

For more detail, see How Resources Can Be Added More Quickly and Effectively to PJM's Grid, OPSI Annual Meeting, October 17, 2023.

DOE's 2024 NTPS confirms significant transmission needs and savings

DOE's National Transmission Planning Study (NTPS) finds that:

1. The lowest-cost U.S. electricity system that can **reliably meet future demand** includes substantial **local, regional, and interregional** transmission expansion
   - To achieve the most cost-effective outcomes, the nation's **transmission capacity would have to expand 50-100% by 2035** and **2.4-4.1 times by 2050** at a cost of $760 billion to $1.4 trillion
   - If well-planned, approximately **$1.60 to $1.80 is saved for every dollar spent** on transmission
2. Multi-state and interregional coordination, using both existing and new local, regional, and interregional transmission, can **save $270 billion to $1 trillion through 2050**
   - The largest savings come from (1) coordinating resource adequacy and (2) expanding interregional transmission to exceed 30% of most regions' peak load
3. To achieve these outcomes, the **consolidation of siloed planning processes** is critical
   - Planning needs to consider extreme events, technology advancements, and demand uncertainty
   - Better interregional coordination is needed to efficiently utilize interregional transmission

Source: Department of Energy, Grid Deployment Office, National Transmission Planning Study, 2024.

Summary of Interregional Transmission Studies

Study	Years analyzed	Considerations/assumptions	Findings
1. DOE 2023 Transmission Needs Study	2030, 2035, 2040	Reviewed of 300 scenarios and sensitivities from 6 independent national transmission studies. Almost all have decarbonization constraints (in addition to BAU scenarios)	Range of additional transmission needs in 2040 from moderate to high decarbonization: **SPP-MISO:** 3.6-98.7 GW **MISO-PJM:** 2.7-119 GW **PJM-SERTP:** 1.5-12.5 GW **ERCOT-SPP:** 0.9-34.9 GW **SERTP-FRCC:** 0-12.9 GW **CAISO-WestConnect:** 0.2-6.9 GW WestConnect-Rockies: 0.4-6.1 GW SPP-SERTP: 0-37.7 GW
2. DOE 2024 National Transmission Planning Study	2035, 2040, 2050	Conducted zonal capacity expansion & resource adequacy modelling through 2050 under 96 scenarios covering different transmission frameworks (AC, P2P HVDC & meshed HVDC), decarbonization assumptions, load growth assumptions, and 15 sensitivity cases	Range of additional transmission needs in 2040 in central case: **SPP-MISO:** 10.2-17 GW **MISO-PJM:** 4.8-12 GW **PJM-SERTP:** 3.4-9.6 GW **ERCOT-SPP:** 6.2-6.7 GW, with an additional 8.3-9.1 GW of new connection from ERCOT to WestConnect **SERTP-FRCC:** 2-2.6 GW **CAISO-WestConnect:** 1.3-4 GW WestConnect-Rockies: 0-4 GW SPP-SERTP: 0-7.3 GW
3. GE-NRDC Study	2035	Uses nodal model to optimize transmission buildout by 2035 and estimate resilience benefits under severe weather events as well as production cost and capacity savings.	$12 billion in net present value from 87 GW interregional transmission (**9.7 GW between SPP-MISO, 7.4 GW between MISO-PJM, 8 GW between PJM-SERTP, and 15.1 GW between SERTP-FRCC**), including $1 billion in resilience benefits from single 2035 polar vortex event.
4. NERC ITCS	2033	Identifies "prudent" interregional transmission additions needed to maintain reliability—does not include any additional transmission justifiable based on economic and public policy benefits	**West-ERCOT:** 9.8 GW **PJM-SERTP:** 1.6 GW **SERTP-FRCC:** 1.2 GW
5. LBNL Analyses	2012–2023	Estimates congestion value (production cost savings) of expanding interregional transmission using historical data (2012-2023) on nodal marginal prices. Does not estimate transfer capability needs in GW.	**MISO-PJM:** documents historical energy market value of $98–107 million/yr per GW of transmission **ERCOT-SPP:** documents historical energy market value of $267–985 million/yr per GW of transmission **CAISO-ERCOT:** documents historical energy market value of $426–436 million/yr per GW of transmission

Examples of Brattle Reports on Regional and Interregional Transmission Planning and Benefit-Cost Analyses

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

PREPARED FOR
WIRES

Link: Well-Planned Transmission

PREPARED BY
Judy W. Chang
Johannes P. Pfeifenberger

May 2016

THE Brattle GROUP

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

PREPARED FOR
WIRES

Link: Effective Transmission Planning

PREPARED BY
Johannes P. Pfeifenberger
Judy W. Chang
Akarsh Sheilendranath

April 2015

The Brattle Group

Link: Transmission Benefits

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

July 2013

Judy W. Chang
Johannes P. Pfeifenberger
J. Michael Hagerty

Link: Diversity Value

BU
Boston University Institute for Sustainable Energy

The Value of Diversifying Uncertain Renewable Generation through the Transmission System

September • 2020

A Roadmap to Improved Interregional Transmission Planning

Link: Interregional Roadmap

PREPARED BY
Johannes P. Pfeifenberger
Kasparas Spokas
J. Michael Hagerty
John Tsoukalis

November 30, 2021

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

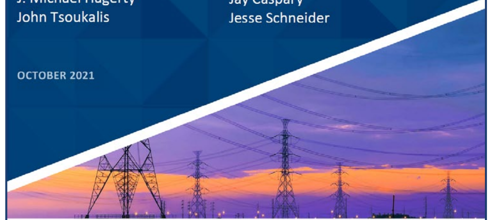
Link: Brattle Grid Strategies

PREPARED BY

The Brattle Group:
Johannes Pfeifenberger
Kasparas Spokas
J. Michael Hagerty
John Tsoukalis

Grid Strategies:
Rob Gramlich
Michael Goggin
Jay Caspary
Jesse Schneider

OCTOBER 2021



Brattle
GRID STRATEGIES LLC

Summarizes proven approaches to quantifying various benefits

Over a decade of US experience already exists for 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

Major Grid Challenges Looking Forward

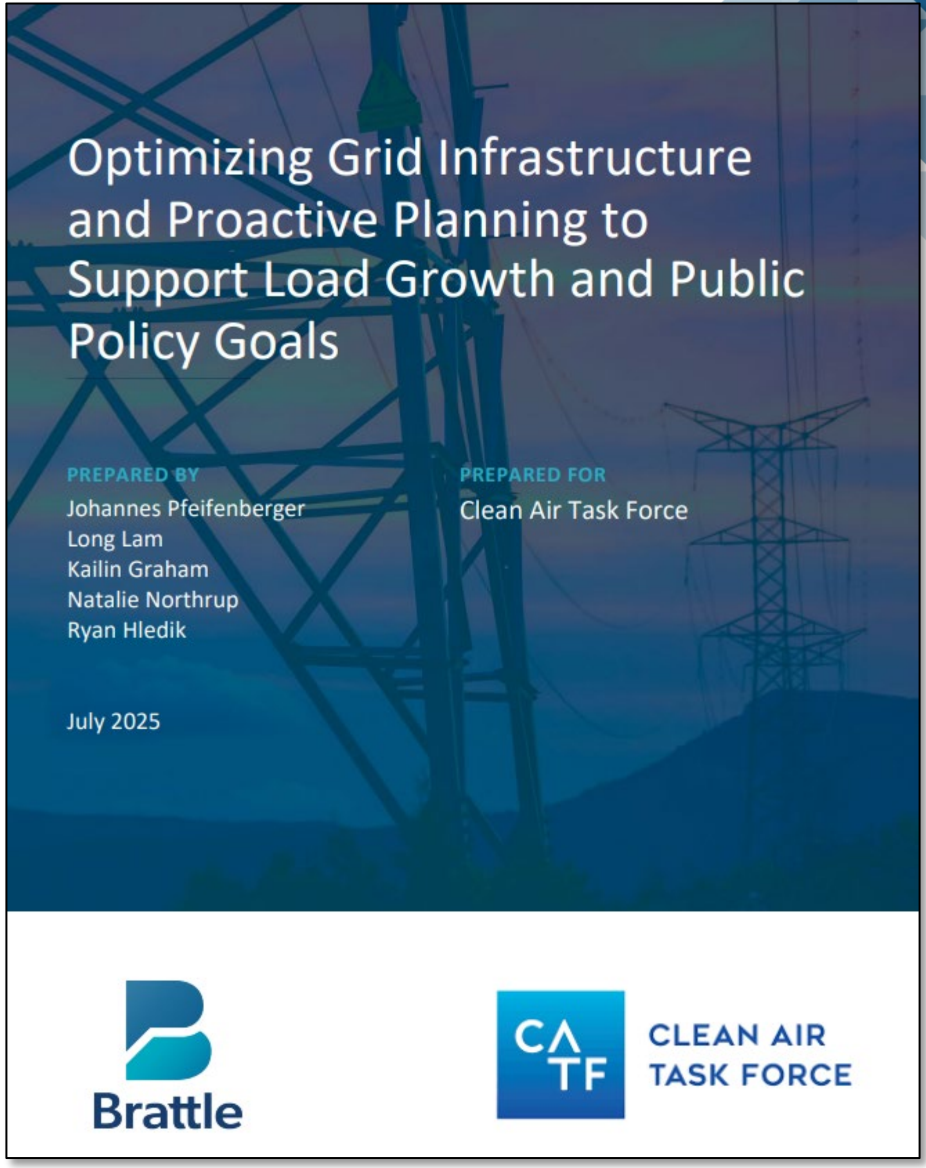
The US electric power system is entering a period of rapid and transformational change due to:

- Accelerating electrification of buildings and transportation
- Re-shoring of industrial activity
- Unprecedented surge in demand from data centers
- Aging grid and generation infrastructure

Meeting this demand will require significant investments grid infrastructure, which can be costly and take a long time:

- Many new large customers are prepared to pay a premium or invest in this infrastructure themselves to avoid interconnection delays
- Capital needs likely exceed the financial capabilities of many utilities
- Affordability challenges and impacts on existing customers create challenges and regulatory risks

Key question: How can utilities, system planners, policymakers, and regulators collaborate to serve new loads more quickly and cost-effectively, while still meeting state and corporate energy goals reliably and affordably?



Report link

How to Support Load Growth and Policy Goals Quickly and Efficiently

I. Maximize the Value of Existing Power System

II. Cost-Effectively Accelerate New Grid Connections

III. Implement Proactive Planning & Procurement

IV. Introduce Targeted Affordability Measures

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

Success Will Require Coordination & Collaboration among Key Stakeholders

SOLUTION	REGULATORS	UTILITIES	GRID PLANNERS /OPERATORS	GOVERNORS LEGISLATORS	OTHERS
I. Maximize the Value of Existing Power System	☑	☑	☑	☑	Third-party DER aggregators
II. Cost-Effectively Accelerate New Grid Connections	☑	☑	☑	☑	Energy park developers
III. Implement Proactive Planning & Procurement	☑	☑	☑	☑	Power procurement authorities; state energy offices
IV. Introduce Targeted Affordability Measures	☑	☑		☑	State energy offices

(See more detailed table in Executive Summary of our July 2025 report.)

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Pfeifenberger, Better Transmission Planning: Proactive, Holistic, Scenario-based, Least-Regrets, with Portfolio-based Cost Allocations, CREPC, Oct 22, 2025.

Pfeifenberger, Integrated System Planning under Uncertainty, LSI Electric Power Conference, September 23, 2025.

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Pfeifenberger, et al., Proposal to Develop Optimal Transmission Planning in Alberta, prepared for AESO, April 2025.

Pfeifenberger, "Intertie Optimization: Achieving Efficient Use of Interregional Transmission," IEEE PES Energy and Policy Forum, April 2025.

DeLosa, et al., Strategic Action Plan, prepared for the Northeast States Collaborative on Interregional Transmission, April 2025.

Pfeifenberger, Transmission Cost Allocation for Order 1920 Compliance, NARUC-NASEO-DOE Webinar, Dec 6, 2024.

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Pfeifenberger, Bay, et al., The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encourage Interregional Transmission, Oct 2023.

Pfeifenberger, Plet, et al., The Operational and Market Benefits of HVDC to System Operators, for GridLab, ACORE, Clean Grid Alliance, Grid United, Pattern Energy, and Allete, September 2023.

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Pfeifenberger, Generation Interconnection and Transmission Planning, ESIG Joint Generation Interconnection Workshop, August 9, 2022.

Pfeifenberger and DeLosa, Proactive, Scenario-Based, Multi-Value Transmission Planning, Presented at PJM Long-Term Transmission Planning Workshop, June 7, 2022.

Pfeifenberger, Planning for Generation Interconnection, Presented at ESIG Special Topic Webinar: Interconnection Study Criteria, May 31, 2022.

RENEW Northeast, A Transmission Blueprint for New England, Prepared with Borea and The Brattle Group, May 25, 2022.

Brattle Group Publications on Transmission (cont'd)

Pfeifenberger, New York State and Regional Transmission Planning for Offshore Wind Generation, NYSERDA Offshore Wind Webinar, March 30, 2022.

Pfeifenberger, The Benefits of Interregional Transmission: Grid Planning for the 21st Century, US DOE National Transmission Planning Study Webinar, March 15, 2022.

Pfeifenberger, 21st Century Transmission Planning: Benefits Quantification and Cost Allocation, for NARUC members of the Joint Federal-State Task Force on Electric Transmission, January 19, 2022.

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

Pfeifenberger, Tsoukalis, Newell, "The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York," Prepared for NYSERDA with Siemens and Hatch, November 9, 2022.

Pfeifenberger et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, Brattle-Grid Strategies, October 2021.

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Van Horn, Pfeifenberger, Ruiz, "The Value of Diversifying Uncertain Renewable Generation through the Transmission System," BU-ISE, October 14, 2020.

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Pfeifenberger, "Cost Savings Offered by Competition in Electric Transmission," Power Markets Today Webinar, December 11, 2019.

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Brattle Group Practices and Industries

ENERGY & UTILITIES

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

LITIGATION

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

INDUSTRIES

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

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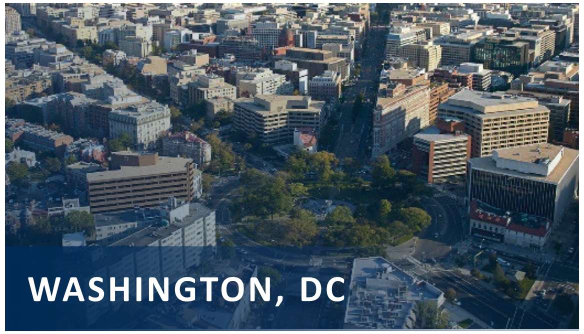
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