Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates

PRESENTED BY

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PRESENTED AT

ESIG
2024 Fall Technical Workshop
Providence, RI

October 22, 2024

Brattle

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

FERC Order 1920 presents a unique opportunity…

We are encouraged by FERC's effort to better align regional transmission planning with best practices for comprehensively assessing long-term transmission values

Key Order 1920 Planning Requirements

Comprehensive long-term planning

- 5-year cycle for plan refresh (minimum)
- 20-year evaluation horizon (minimum)
- For at least 7 drivers of transmission needs, asset refurbishments, and generator interconnection

Scenario-based

- *At least* three *plausible* and *diverse* scenarios, and *at least* one "stress test" extreme weather sensitivity for each scenario

At least 7 benefits metrics

Broader set of solutions: GETs, upsizing

Cost allocations: default or state sponsored

Better *interregional coordination* and transparency

Possible Impacts & Opportunities

- RTOs have opportunity to **adopt best practices**
  - New transmission planning processes may require additional expertise and new tools
- Requirements, especially the explicit treatment of uncertainty, could spur **more robust planning frameworks and modeling approaches**
- Minimum standards for scenarios and benefits analysis have potential to **improve consistency of planning and the development of solutions that reduce long-term costs**
- Opportunity to **consolidate siloed existing planning processes** (local and asset refurbishment, regional reliability, economic, public policy, generator interconnection)

Order 1920 requires selection criteria for potential inclusion of projects in transmission plans but does not mandate the selection of any projects (see Order 1920 Explainer)

…but leaves room for concerns and improvements

Order 1920 creates a new long-term planning process, but does not require modifications to existing processes or the selection of near-term projects

- There is a risk that existing processes result in transmission solutions (to address near term needs) that continue to preempt more efficient, more comprehensive, long-term solutions

Effectiveness of 1920 will depend on how ISOs/RTOs implement it

- Will scenario planning be comprehensive and used broadly to inform transmission plans, near- and long-term?
- Will "least regrets" planning (not required) be used evaluate at the risks of both over- and under-building?
- Will planners develop flexible/expandable solutions that reduce costs and mitigate risks of long-term uncertainties?
- What additional benefits metrics will ISO/RTOs elect to include beyond the mandated seven?
  - **Diversification of weather & load uncertainty; deferred generation investments; access to lower-cost generation**

Even under the best possible circumstances, we don't expect Order 1920 processes to identify new transmission for 5 years and expand transmission not for another decade!

1920 does not require *<u>inter</u>*regional transmission planning

- Increased coordination requirement and process to consider project proposals will help. But unlikely leads to systematic exploration for opportunities to reduce costs and maintain reliability/resilience more cost-effectively through interregional projects

Order 1920 compliance opportunities

1. Better deal with long-term uncertainties through proactive scenario-based planning
2. Use best-practice experience for benefit quantification
3. Consolidate silo-ed planning processes
4. Employ least-regrets planning criteria to minimize the risk of both over-building and under-sizing
5. Develop more flexible transmission solutions
6. Embrace ATTs/GETs, focus on cost effectiveness, and include cost-control incentives
7. Explicitly consider interregional solutions to regional needs

Best practices for proactive, comprehensive, long-term planning

The benefits (overall cost savings) of proactive planning increase for transmission planning processes that:

1. Comprehensively consider all transmission needs over longer time frames (i.e., consolidate planning for two+ decades of already- known or likely needs for generator interconnection, local and regional reliability, economic benefits, and public policies, as opposed to need at a time)
2. Use proactive, multi-value planning processes to address both urgent near-term needs and long-term needs, utilizing scenario-based planning to address long-term uncertainties
3. Reduce the scope of network upgrades triggered by generator interconnection through the proactive planning process (and improve generator interconnection study criteria)
4. Look beyond regional seams to identify more cost-effective interregional solutions to the range of identified transmission needs
5. Rely on advanced transmission technologies, upsizing opportunities, and flexible solutions to address identified needs and enhance the grid
6. Utilize pragmatic cost allocations that are roughly commensurate with (but not formulaically based on) benefits received

What is scenario-based, long-term planning?

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

Scenario-based planning is a multi-step process:

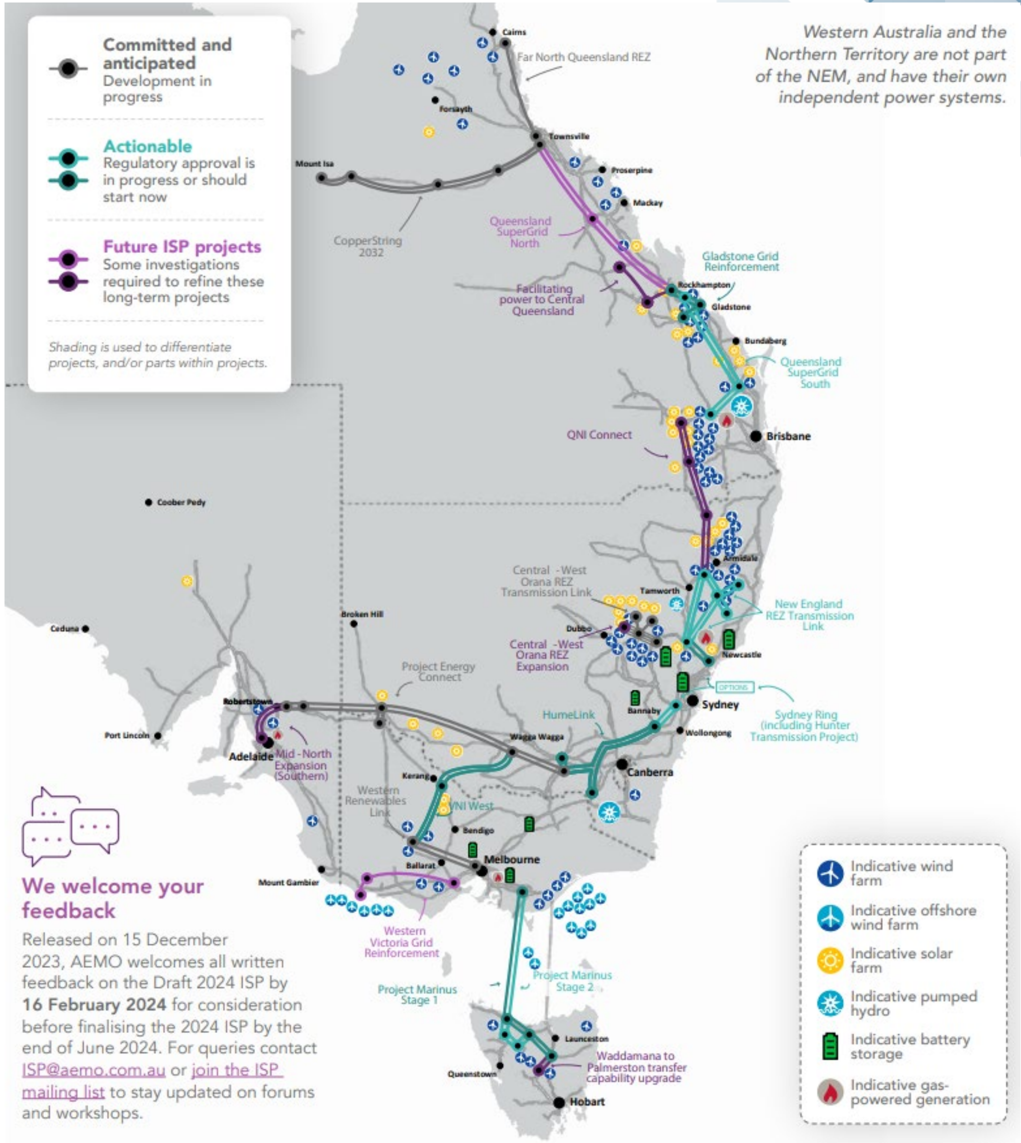
1. Define scenarios of plausible futures by scanning the current reality, trends and forecasts, uncertainties, and important internal and external drivers
2. Develop a series of plans (initiatives, projects, policies, tactics) that work well across multiple scenarios (e.g., by developing **solutions 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)

Example: Australian Integrated System Plan (ISP)

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

- Clearly-specified 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)
  - Plans distinguish: (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
  - 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)
- 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

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, including benefits beyond the 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

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

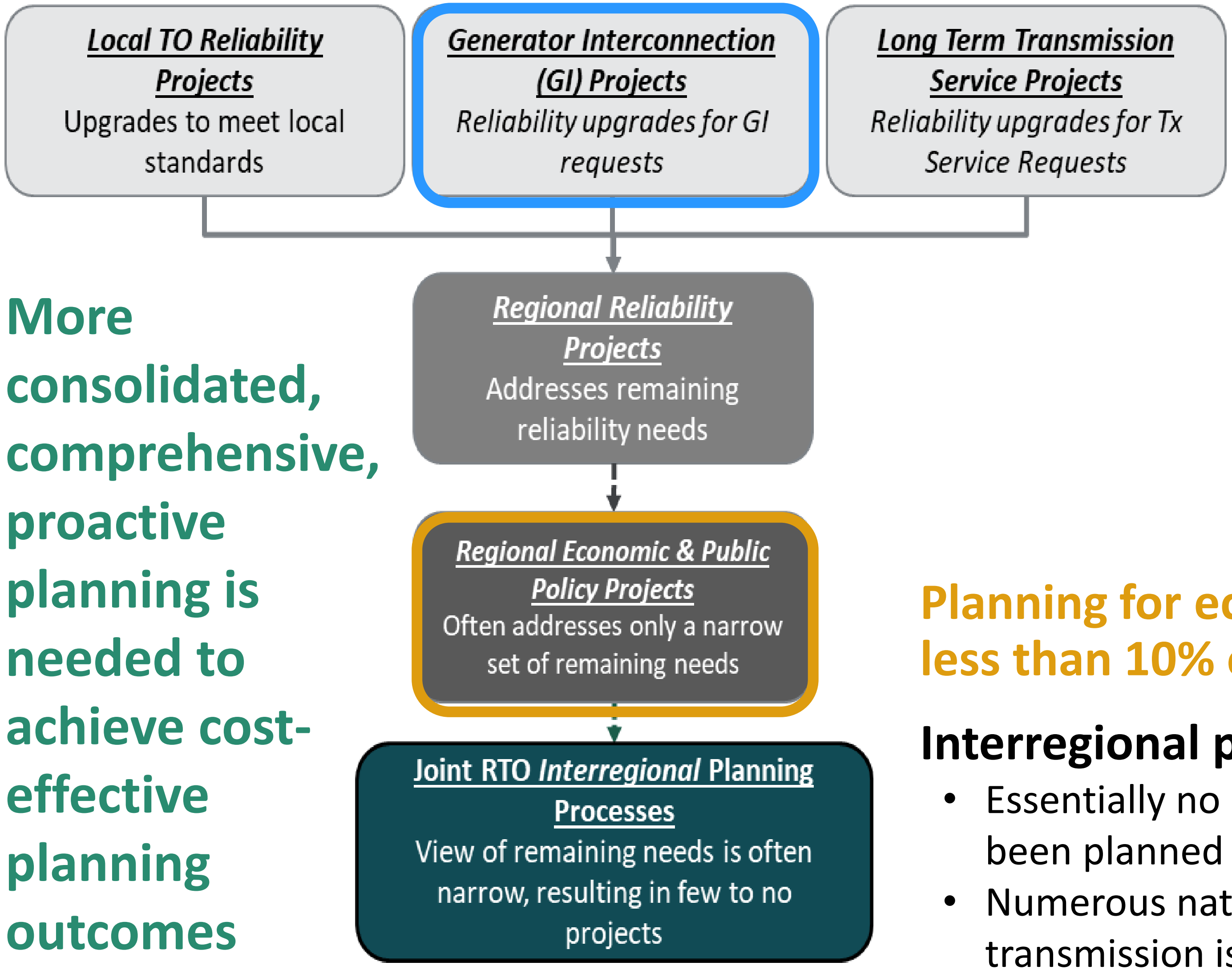
Not quantified

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

Order 1920 compliance is an opportunity to consolidate siloed and overly reliability-focused transmission planning



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

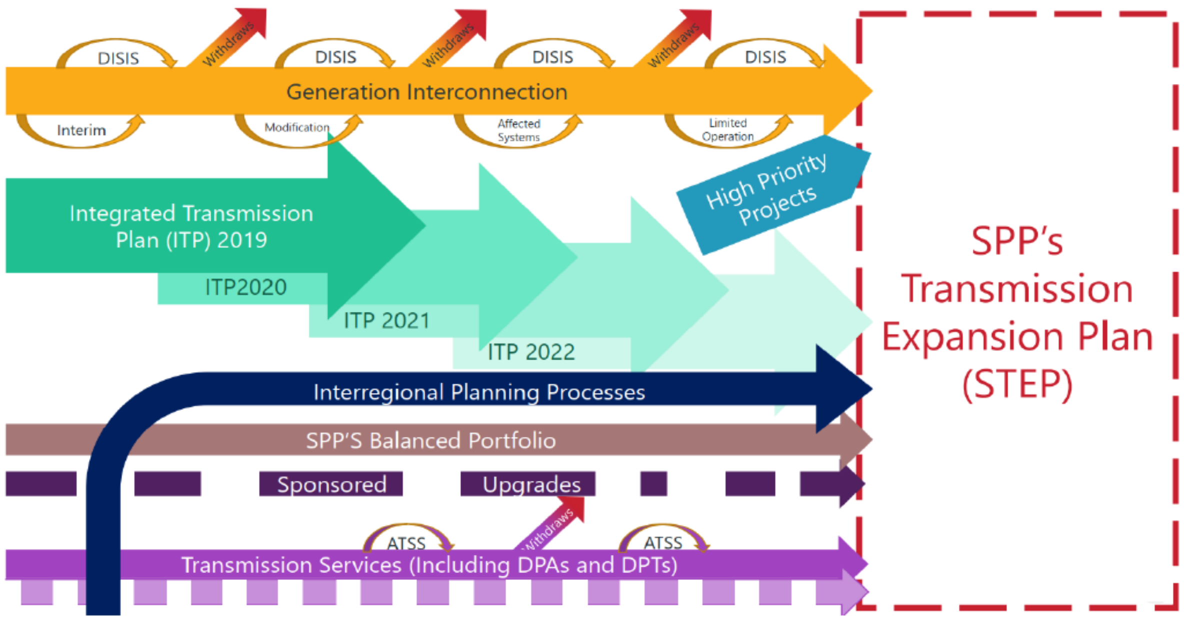
- Essentially no major interregional transmission projects have been planned and built in the last decade
- Numerous national studies show that more interregional transmission is needed to reduce total system costs

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

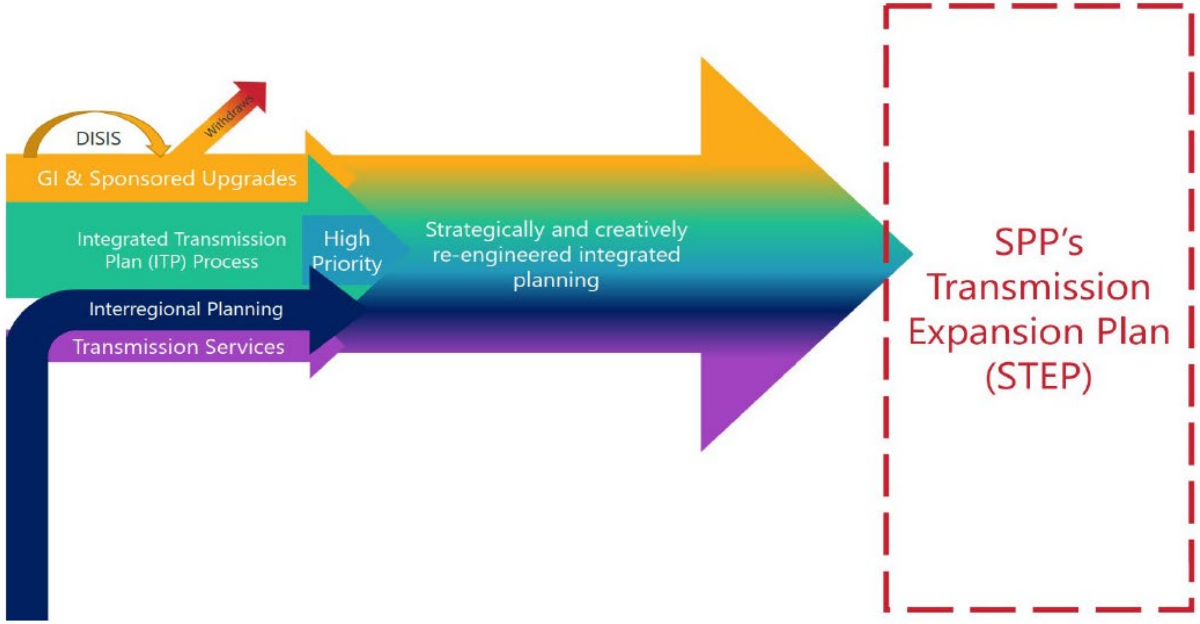
Example: SPP's proposed Consolidated Planning Process (CPP)

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:

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

Risk mitigation through proactive "least-regrets" planning

Proactive planning needs to consider both (1) the high risk of delaying infrastructure investment and (2) the risk-mitigation offered by alternative transmission solutions:

- 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 can limit options, so can be more costly in the long term
  - We need to plan for both short- and long-term uncertainties more proactively – and develop least-regrets solutions that comprehensively and flexibly address uncertain future needs
- **"Least regrets" planning** to minimize the risk of both overbuilding and undersizing

  Use full set of scenarios in planning to identify solutions that minimize both sources of possible regrets:
  1. Avoid oversized projects that "regrettably" end up too costly and under-utilized; and also
  2. Avoid many "regrettable" high-cost outcomes caused by undersized transmission solutions
- Focusing on just one scenario cannot distinguish solutions with higher/lower costs and risk
- Taking probability-weighted averages across scenarios is insufficient as it (a) assumes risk neutrality and (b) does not quantify the value of flexibility and risk mitigation

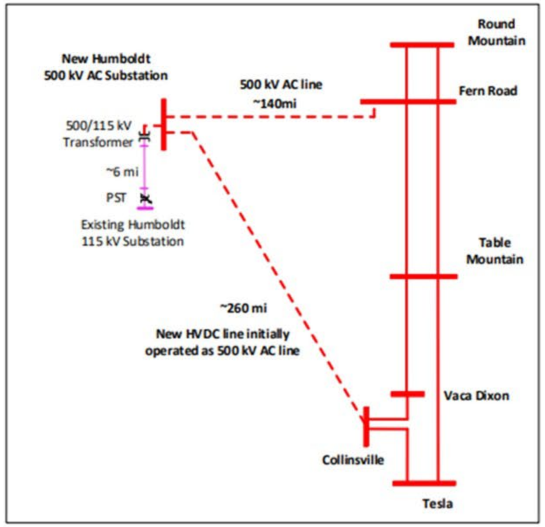
Reduce costs and mitigate risk through more flexible solutions

Planning processes need to develop flexible transmission 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:

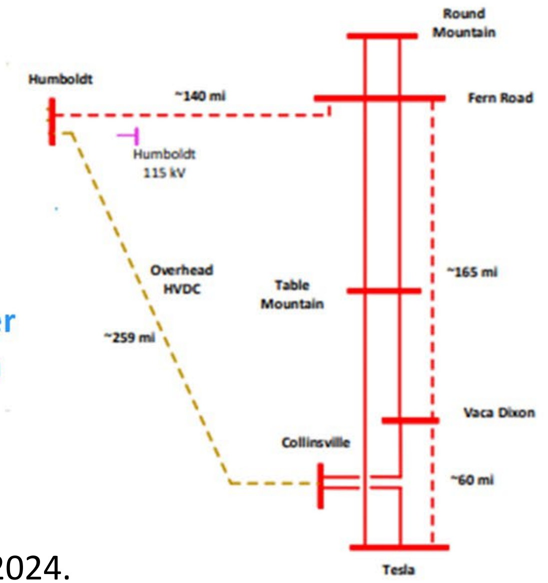
Two new 500kV lines, of which one is "HVDC-ready"

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



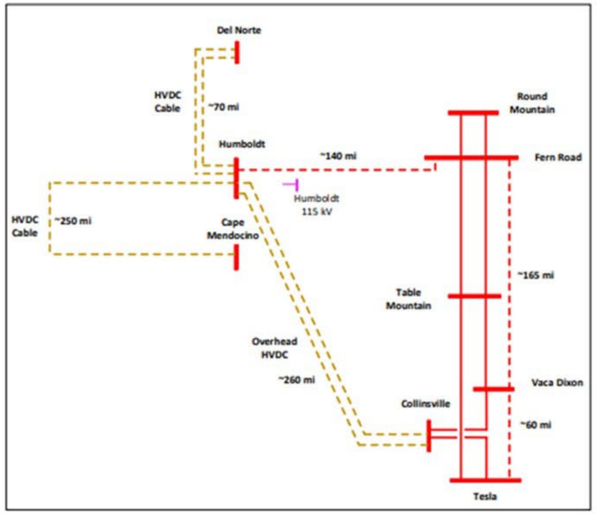
Add DC converter stations to each end of the line

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.

Options for achieving 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

How can we double or triple US transmission capability … and 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

3. New transmission

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

2. Upgrades of existing lines

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

Examples:

Priority order required by the German "NOVA Principle"

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

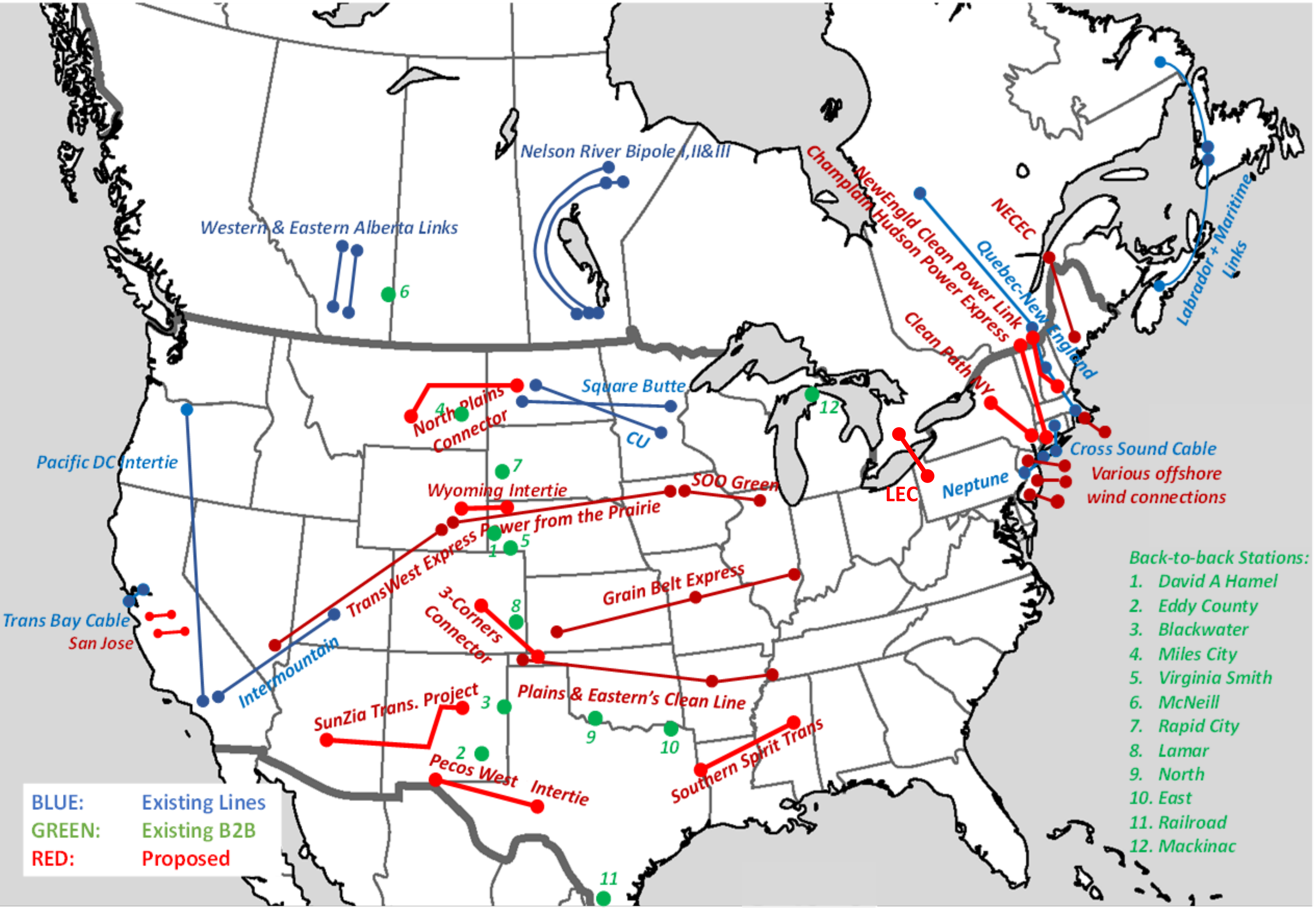
More efficiently plan and utilize interregional transmission

Significant seams-related inefficiencies exist between RTO markets, which need to be addressed to capture the full value of both existing and new interregional transmission:

1. **Interregional transmission planning** is mostly not existing or ineffective (beyond merchant T)
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. **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)
4. **Loop flow management** through market-to-market coordinated flowgates (with shares of firm flow entitlements) under the existing JOAs
5. **Inefficient trading** across contract-path market seams and the need for intertie optimization (see link)

Today, in the US interregional transmission needs are addressed mostly through proposed merchant HVDC lines

North American HVDC Projects (Existing and Planned/Proposed)



Source: Jim McCalley, Iowa State University

Most U.S. interregional transmission projects are HVDC lines proposed by merchant and OSW developers (i.e, not planned by system operators)

Main HVDC advantages:

- High capacity (1-5 GW), long-distance
- Efficient right of way (including underground and submarine)
- Controllable power flows (for transmission access, economic dispatch and during contingencies)
- Synchronous and asynchronous applications
- Grid-forming capability / weak AC grids
- Grid services (to support AC network)

Order 1920 may facilitate planning of interregional transmission

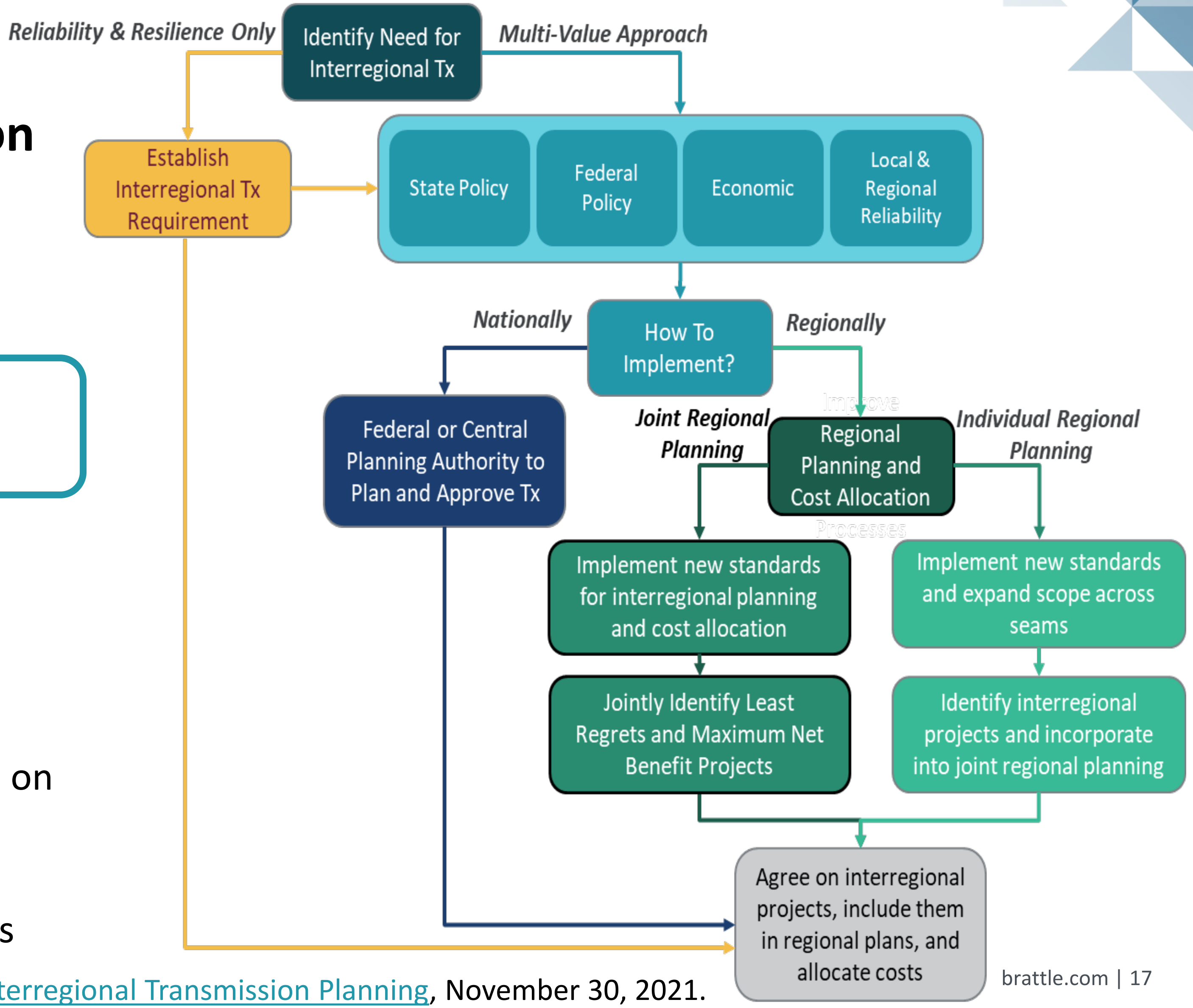
Four pathways are available for actionable interregional transmission planning:

1. New Interregional Tx requirements?
2. New Federal planning?
3. Improve joint RTO planning
4. Expand planning by individual RTOs

These could be improved trough Order 1920 compliance

Order 1920 only requires improved interregional coordination:

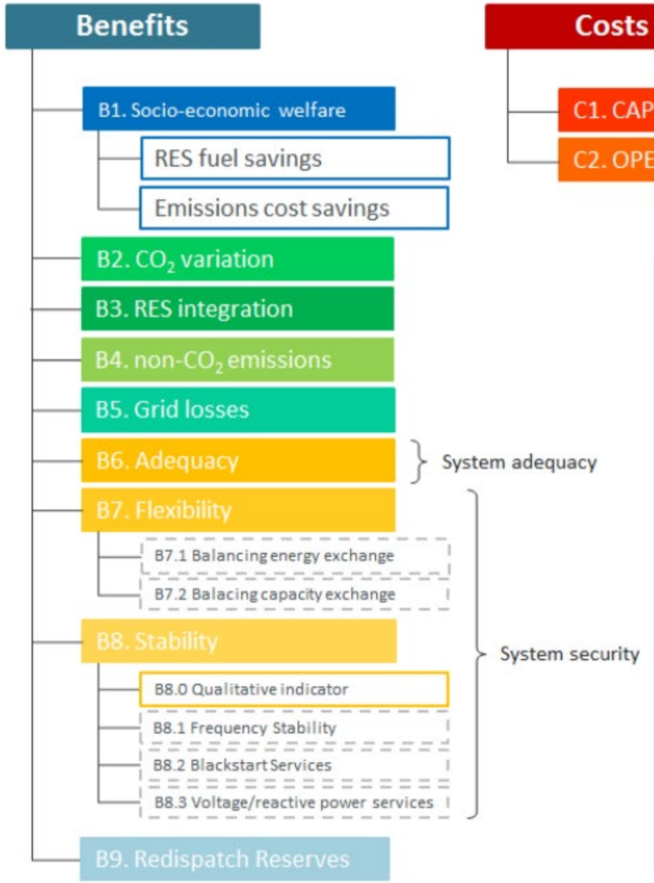
- Sharing new long-term planning information on needs and possible solutions
- Process for proposing interregional projects
- Regional evaluations of interregional projects



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

Example: Continent-wide proactive, multi-value planning. The European 10-year Network Development Plan (TYNDP)

ENTSO-E: Standardized Multi-value Benefit-Cost Analysis Framework for EU-wide Transmission Planning (incl. HVDC)

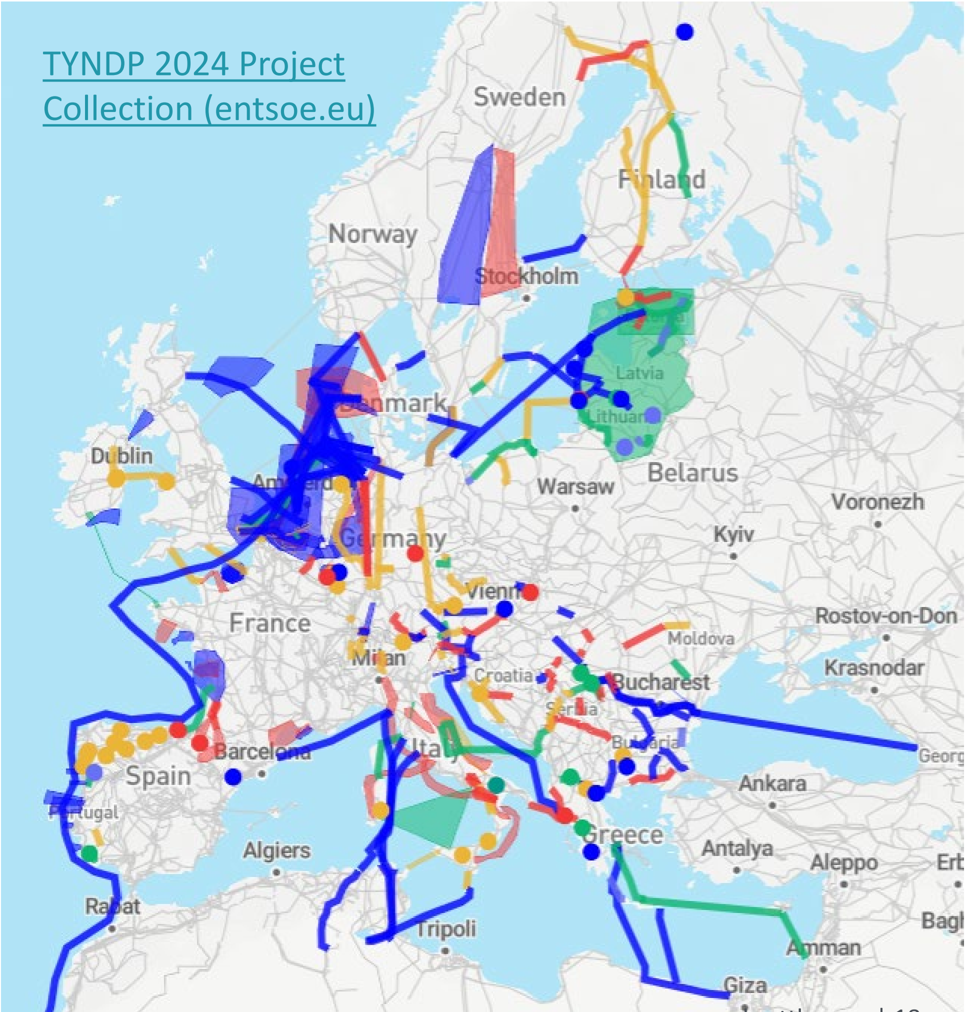


Entso-E Planning and CBA framework

- Association of European Grid Operators
- 10 year investment plan
- Scenario-based looking out 10-30 years
- Standardized benefit-cost analysis
- Specifically addresses HVDC benefits: Cost savings achievable from optimized dispatch of HVDC lines; transient, voltage, and frequency stability benefits of HVDC lines; blackstart services; voltage and reactive power support

Source: ENTSO-e, *4th ENTSO-e Guideline for Cost Benefit Analysis of Grid Development Projects*, Oct 18, 2023, Figure 8; TYNDP 2024 Implementation Guidelines, Mar 4, 2024.
For a summary of the ENSTO-e framework, incl. HVDC, see pp. 77-80 here.

10-Year Network Development Plan (TYNDP) to Evaluate 176 Transmission, 33 Storage Projects



Thank You!

(Additional Slides)

About the Speakers

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(webbio and publications)

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 market design, renewable energy, electricity storage, and transmission. He also is a Visiting Scholar at MIT's Center for Energy and Environmental Policy Research (CEEPR), a former Senior Fellow at Boston University's Institute of Sustainable Energy (BU-ISE), a IEEE Senior Member, and currently serves as an advisor to research initiatives by the U.S. Department of Energy, the National Labs, and the Energy Systems Integration Group (ESIG).

Hannes 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.

The main drivers of transmission needs

The structural changes in the electricity industry contribute significant transmission investment needs, driven mainly by:

1. Renewed load growth
2. The need to refurbish aging transmission infrastructure
3. Generator interconnection needs, particularly for clean-energy resources
4. Poorly-timed and -planned retirements of aging generating plants
5. The economic and resilience benefits of broader regional and interregional diversification

Investments necessary to upgrade the existing grid and build new transmission infrastructure will quickly exceed acceptable rate impact and available financing

… unless mitigated through (a) targeted EE, DER, BESS; (b) GETs, advanced transmission technologies, more efficient grid operations; (c) upsizing existing lines and ROWs; and (d) proactive planning

Substantial new load growth projected through 2030

Load growth from data centers, cypto mining, and industrial, transportation, and building electrification is projected to add more than 75 GW of load over the next 6 years.

- Transmission vs. T&D investments for load
- Added demand for clean-energy generation will require additional transmission

CRYPTOCURRENCY MINING

Cryptocurrency mining is the process by which networks of computers generate and release new currencies and verify new transactions. Load from cryptocurrency mining is challenging to estimate because of its unique operational characteristics.

Current capacity: ~10–17 GW
Estimated electricity demand increase by 2030: +8–15 GW

DATA CENTERS

Data centers underpin the online economy technology sector and support the growth of artificial intelligence.

Current capacity: ~19 GW
Estimated electricity demand increase by 2030: +16 GW

TRANSPORTATION ELECTRIFICATION

A growing number of customers purchase electric passenger vehicles as a more climate-friendly alternative to gas vehicles; medium- and heavy-duty vehicles, motorcycles, and ferries can all operate on electricity.

Current capacity: ~7 GW (electric vehicles)
Estimated electricity demand increase by 2030: +8 GW

ONSHORING & INDUSTRIAL ELECTRIFICATION

Electrification of the industrial sector is a major pathway to reduce emissions. New sources of electric demand are triggered by the onshoring of manufacturing activity, hydrogen production (e.g., electrolyzers), indoor agriculture, and carbon dioxide removal.

Current capacity: ~116 GW
Estimated electricity demand increase by 2030: +36 GW

BUILDING ELECTRIFICATION

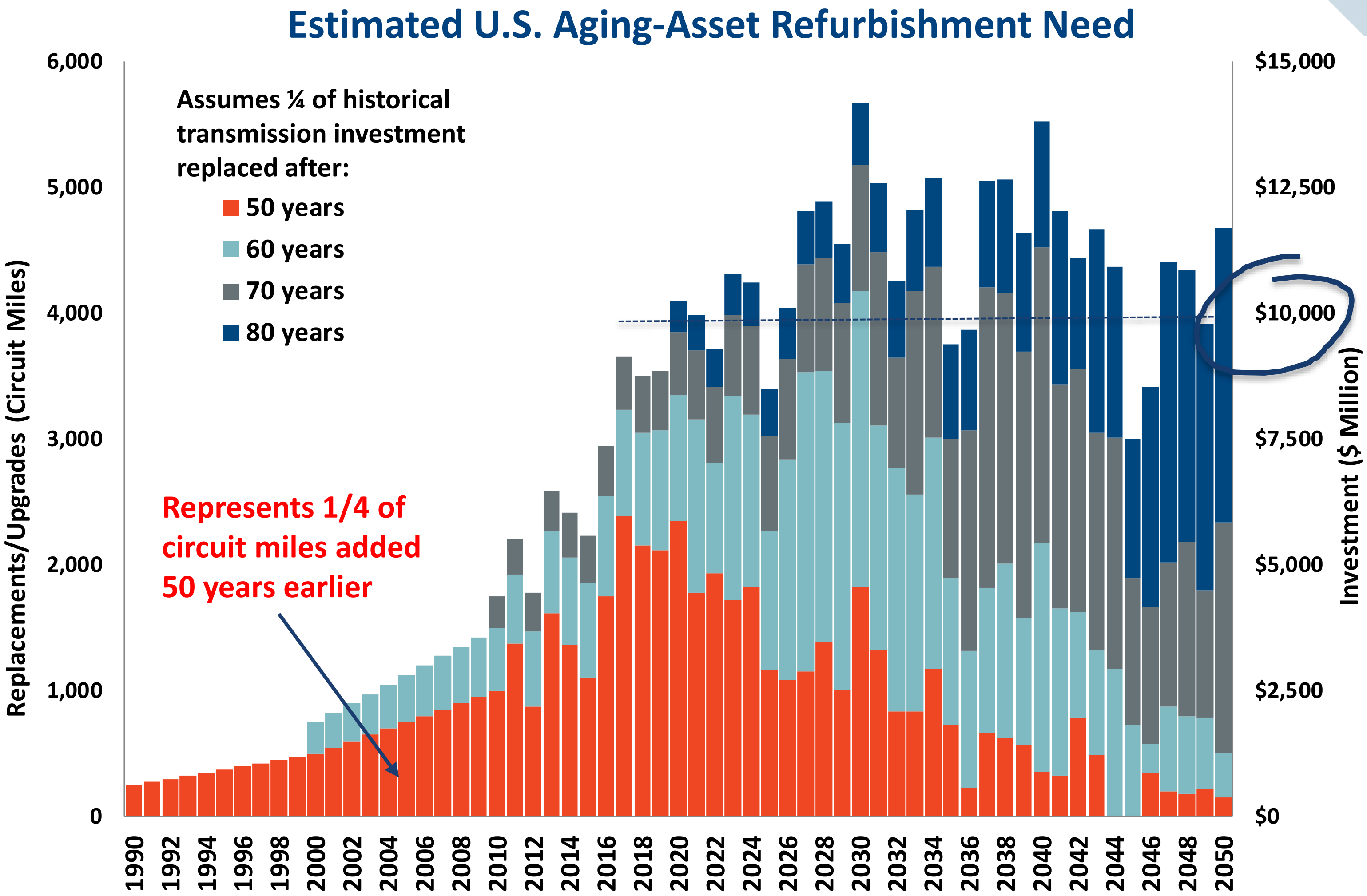
Electrification is a major pathway to decarbonize buildings and can include space heating (e.g., heat pumps), water heating (e.g., heat pump water heaters), and cooking (e.g., electric/ induction cook stoves).

Current capacity: ~50 GW
Estimated electricity demand increase by 2030: +7 GW

Source: Brattle, Electricity Demand Growth and Forecasting in a Time of Change, May 2024

A large part of it: refurbishment of the aging US grid

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

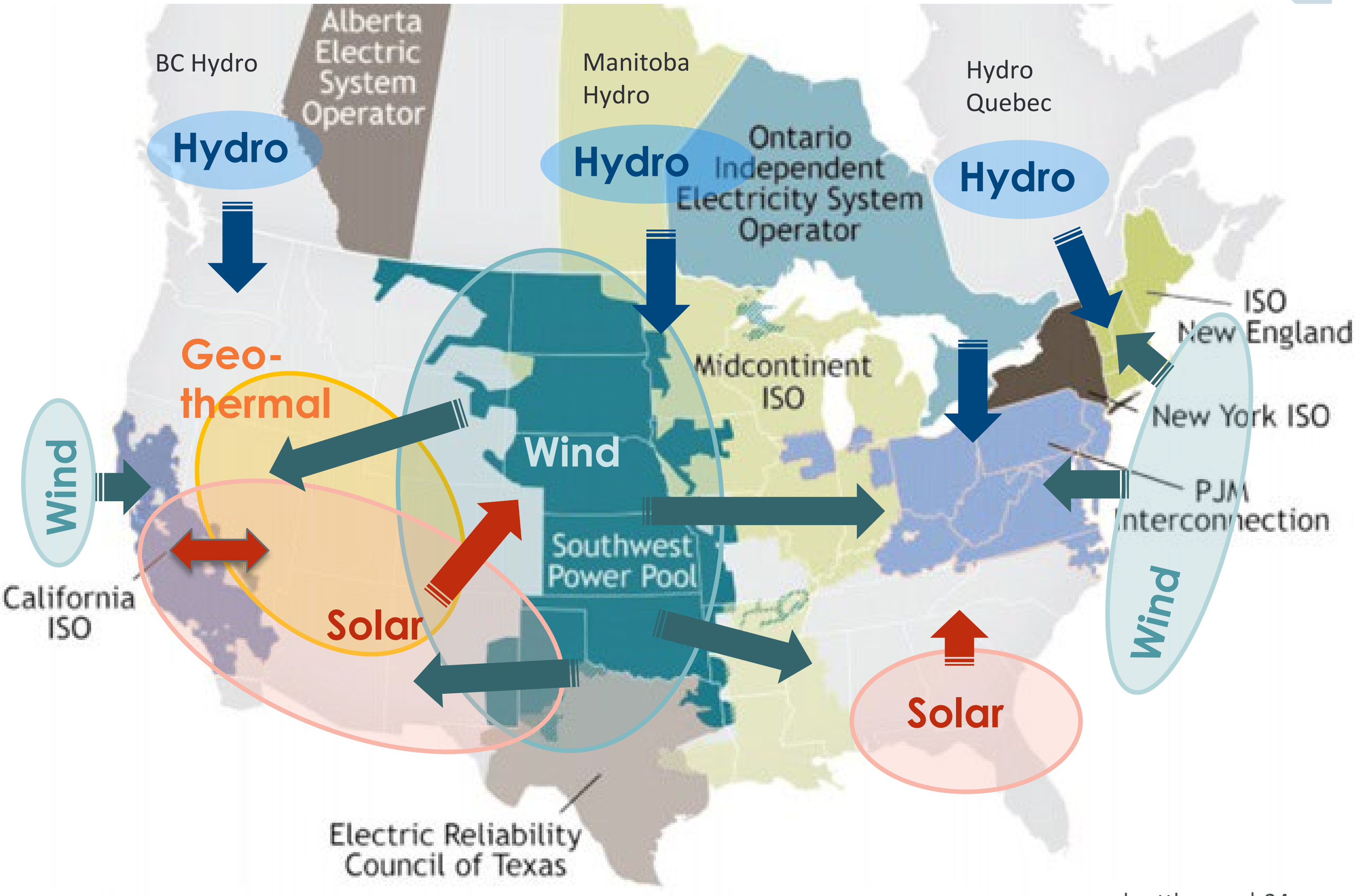


Source: Brattle estimate. Assumes $2.5 million per refurbished circuit mile

More interregional transmission will be beneficial to access and diversify low-cost renewable generation

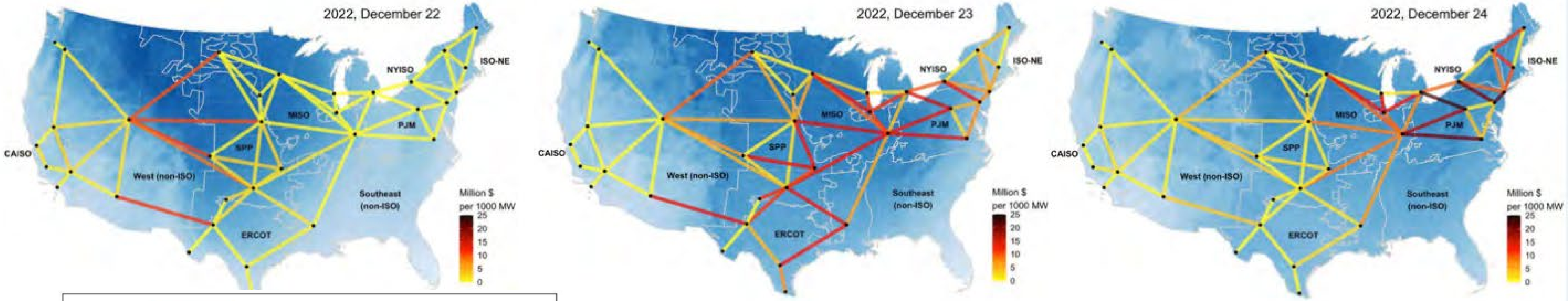
Beyond providing access to low-cost resources, grid-based resource diversification offers increasingly significant benefits:

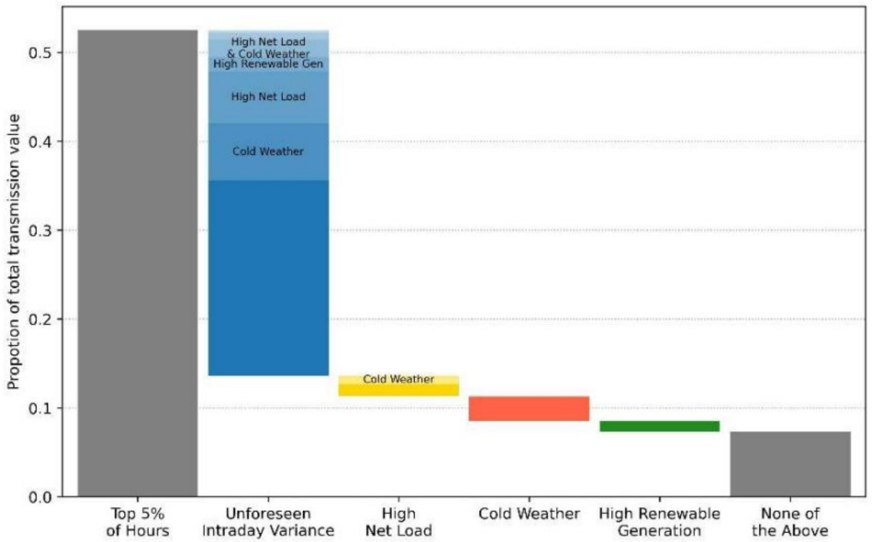
- Regional diversification of resources and customers' electricity usage reduces the investment and balancing cost in a future with high levels of intermittent resources
- Diversity of resources and load increases the value of transmission between them
- **The scale of robust grid solutions needs to exceed the size of large weather systems**



Transmission value is concentrated in only a few challenging hours

Highest transmission congestion is concentrated in relatively few hours of the year and during extreme events. Example: **Winterstorm Elliot** (2022)



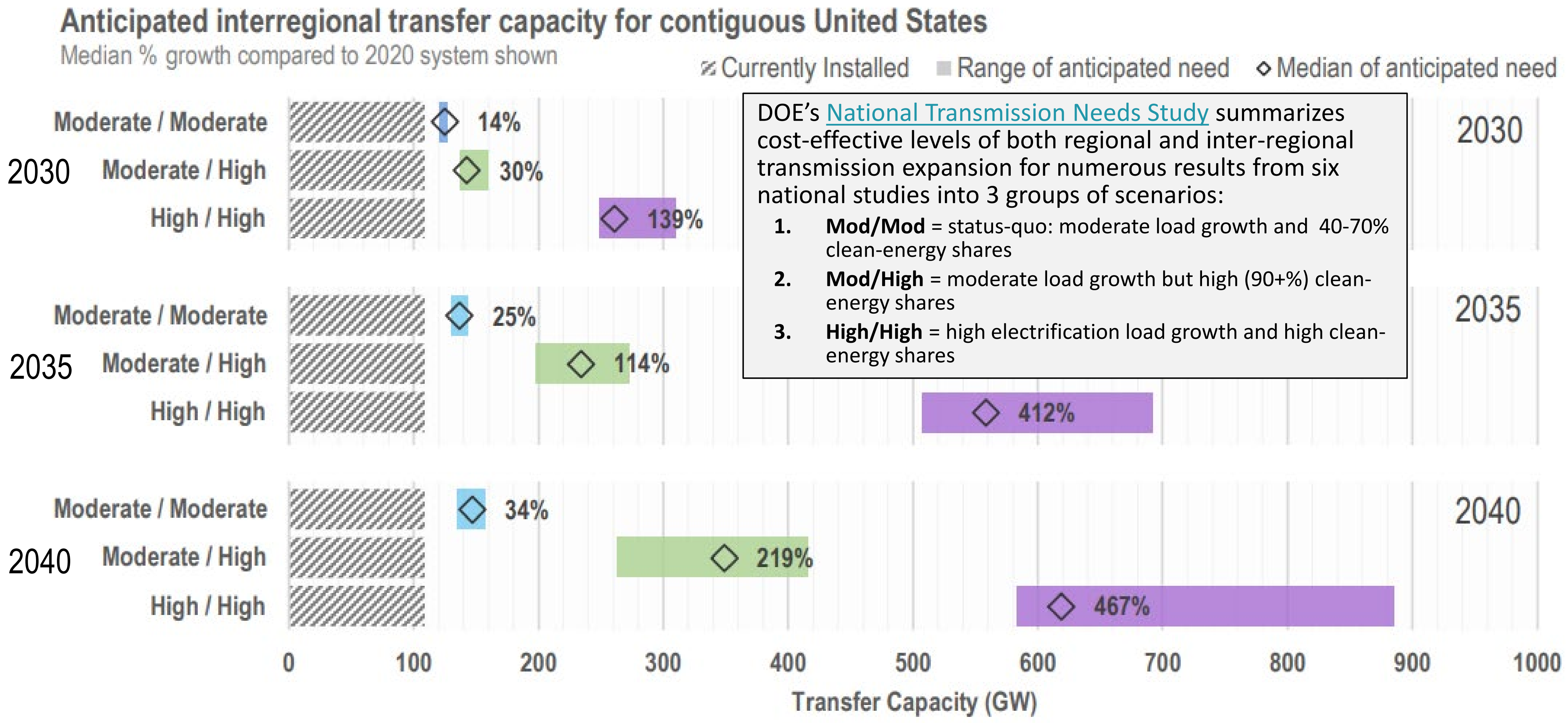


Findings:

- Real-time values (reflecting actual conditions) are higher than DA values
- On average, about **half of the value is concentrated in top 5% of all hours**
- Most of that value is due to unpredictable real-time market conditions that are not foreseeable on a day-ahead basis
- Estimated benefits exceed costs of expanding interregional paths

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

DOE’s 2023 Transmission Needs Study: Interregional Needs



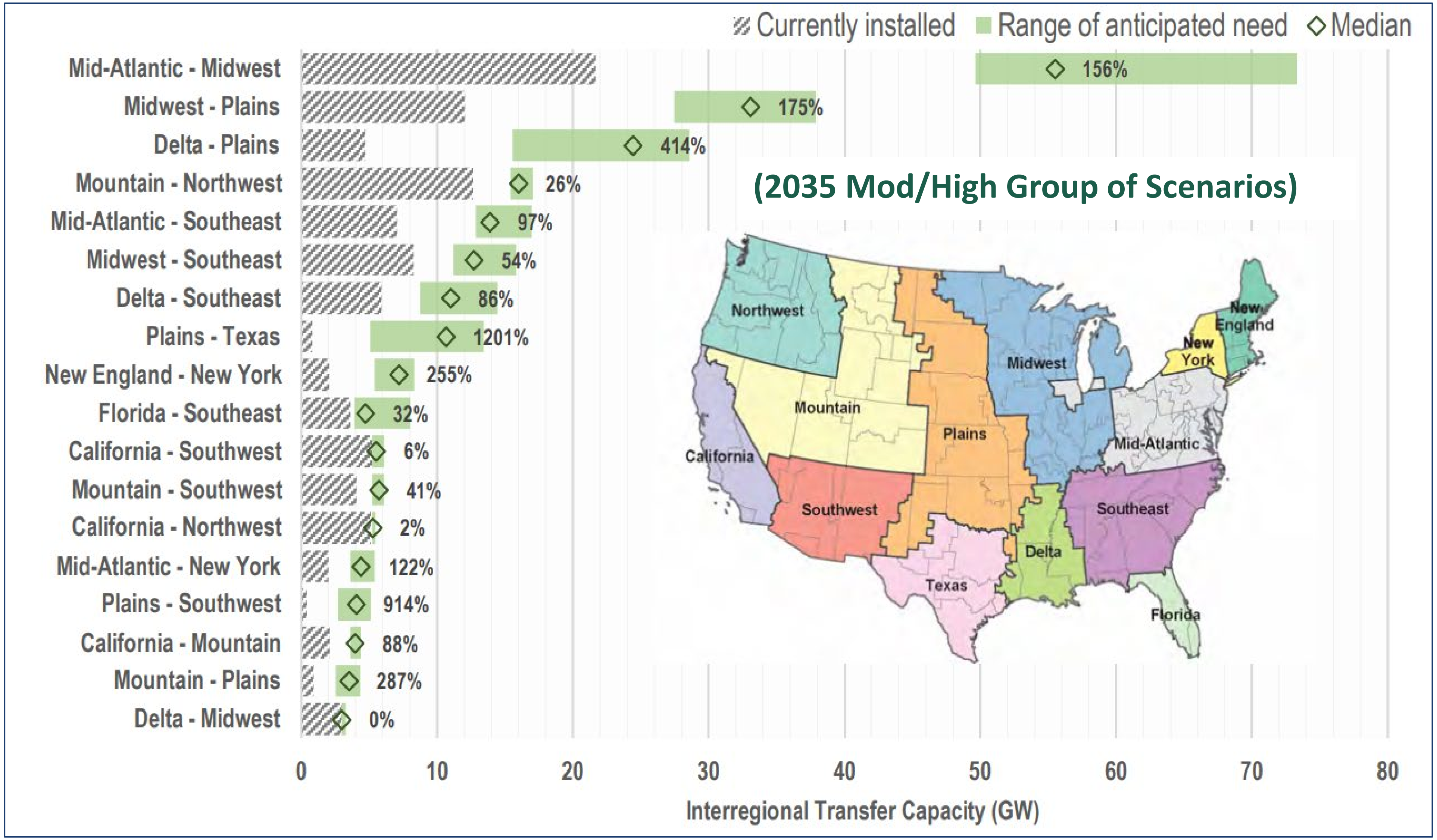
DOE’s National Transmission Needs Study summarizes cost-effective levels of both regional and inter-regional transmission expansion for numerous results from six national studies into 3 groups of scenarios:

1. **Mod/Mod** = status-quo: moderate load growth and 40-70% clean-energy shares
2. **Mod/High** = moderate load growth but high (90+%) clean-energy shares
3. **High/High** = high electrification load growth and high clean-energy shares

Source: DOE, National Transmission Needs Study, October 2023 (report) and Department of Energy’s 2023 National Transmission Needs Study (slides)

Note: Expansion options include enhancing the existing grid & existing ROW plus new transmission lines

DOE's 2023 Transmission Needs Study: 2035 Interregional Needs



Source: DOE, National Transmission Needs Study, October 2023 (report) and Department of Energy's 2023 National Transmission Needs Study (slides)

Note: Expansion options include enhancing the existing grid & existing ROW plus new transmission lines

DOE's 2024 NTPS confirms significant future transmission needs

DOE recently-completed 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.

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:

- 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**: they often do not identify specific transmission projects nor do they support an actionable need such projects
  - The results of these <u>studies do not connect with RTO planning processes and needs identification</u>
- 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 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, reduced 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

Impact of increasingly cost-effective renewables, storage, and advanced transmission technologies

The declining costs and accelerating adoption of new energy technologies has profound implications on how the grid will have to be planned and operated in the future:

- **Declining costs of battery storage** (and exponentially-increasing deployment) will mean:
  - Grid reliability, resource adequacy, and resilience will increasingly shift from being provided by a centralized grid to rely more on distributed generation and storage resources
  - The role of the regional and interregional grid will increasing shift from instantaneously delivering energy+capacity to delivering sufficient energy on a daily basis from a geographically-diverse set of resources
- **Declining cost of solar** generation will mean increased utilization of the local T&D grid, but combined with need to diversify over geographic areas larger than typical weather systems
- **Declining cost of wind** generation will mean increased need for regional and interregional transmission to access (and diversify geographically) utility-scale wind plants in low-cost regions
- **Advanced transmission technologies** (dynamic line ratings, flow and topology control) can help keep transmission to be a cost-effective, competitive solution in light of declining renewables+storage costs
  - But near-term fears of “lower ratebase” would need to be replaced with a longer-term strategic goal of keeping transmission competitive in face of declining costs of competing technologies (solar, storage)

Advanced Grid Technologies: Fast and cost-effective solutions

Advanced and grid-enhancing transmission (GET) technologies can (1) significantly and quickly increase the capability of the existing grid, (2) offer low-cost solutions to address near-term reliability needs, and (3) also make new transmission more valuable and cost effective in the long-term

- Value proposition: more visibility of actual grid capability; shift flows to underutilized portions of the grid
- Increasingly well-tested and commercially-available technologies include: dynamic line rating, smart wires and flow control devices, grid-optimized storage, topology optimization, advanced conductors
- Can be deployed quickly to integrate renewables on the existing grid (see Chapter III of NY Power Grid Study)
- Brattle case study in SPP: DLR, topology optimization, and advanced power-flow controls can integrate 2,670 MW of renewable generation for only $90 million
- See also discussion in MA CETWG report (Section 7), CurrENT's report, topology optimization case studies

Consideration of GETs needs to be expanded beyond addressing operational and congestion needs– GETs should be part of the standard set of available solutions to address generation interconnection and both short- and long-term transmission planning needs

- As low-cost solutions to address reliability needs identified in generation interconnection and near-term planning
- In long-term multi-value planning to make new transmission more cost effective and valuable, reducing system-wide costs

The Challenge: How to keep the energy transition affordable

The challenge to achieving an affordable clean-energy transition is formidable:

1. Much of the (aging) existing generating resources will need to be replaced over the next two decades
2. Electrification and data center load growth will double the amount of generation supply needed (even with EE)
3. Local, regional, and interregional transmission capacity will need to double or triple to achieve a cost-effective outcome (as numerous studies have already shown)

More investment will be needed than can easily be provided and recovered

Unless done efficiently and cost-effectively, the size of investments and customer rate impacts will quickly exceed feasible and acceptable levels!

Nobody will be "happy" if rates start to exceed certain levels

- Unaffordable rates will undermine or delay policy goals
- High fixed costs will create uneconomic bypass of existing facilities, which will further increase total costs
- Unhappy customers and regulators create risk and challenges for regulated companies and their investors
- Utility credit ratings will deteriorate and limit the amount of investments that can be financed

Improve incentives to control project costs and deploy lower-cost solutions

Expanded use of cost-control incentives is advisable. Examples include:

- **Broad-based** performance-based ratemaking (PBR),
  - UK incentives for transmission providers (for both investments and operations) under "RIIO"
  - Australian incentive schemes for networks: efficiency benefits sharing scheme (EBSS), capital expenditure sharing scheme (CESS), and service target performance incentive scheme (STPIS)
- **Project-specific** cost-control and targeted cost-sharing incentives
  - Hard or soft cost caps (with adjustments for some uncontrollable factors)
    - Examples: NJ SAA Evaluation Report, Appendix E
  - Shared savings incentives for project cost (and schedule) under/overruns
    - Australian 70/30 sharing mechanism (for realized vs. forecast costs) under CESS
    - NY PPTN: at least 80/20 sharing strongly encouraged (NYISO tariff at 31.4.5.1.8.3, FERC order, recent award)
    - Proposed shared savings incentives for GETs (e.g., link1, link2)
  - The project-specific "baselines" of expected costs can be: (1) competitive bids, (2) independent cost estimates, or (3) menu-based "revealed expectations" mechanisms
- **Cost reviews** of significant overruns
  - Australian targeted ex-post review process

Competitive procurements: innovation and reduced costs

In the U.S., FERC's Order No. 1000 was intended to promote "more efficient or cost-effective transmission development" through competitive procurements

Solutions-Based Procurements | **Project-Based Procurements**

Transmission Needs Assessment → Solutions Solicited, Proposed and Selected → Projects Solicited, Offered and Selected

Developers compete to provide, finance, build, own, and operate innovative solutions to meet specified needs

- Planning entities identify needs and solicit innovative solutions
- Planning entities select preferred solution; selected developers finance, build, own, and operate projects
- **Examples: PJM, NYISO, UK**

Developers compete to finance, build, own, and operate pre-specified projects

- Planning entities identify need and specify solution; solicit bids for the specified project
- Planning entities select developer to finance, construct, and own the projects based on factors including bid prices
- **Examples: CAISO, MISO, SPP, Brazil, Alberta, Ontario**

Several studies of competitive procurements in the U.S., Canada, U.K., and Brazil show that competitive solicitations yield **more innovative solutions** and **cost savings of 20-30%,** yet less than 5% of projects are subject to competitive procurements

U.S. Reports on Competitive Transmission

Making the case for competition in electric transmission:

- 230609-caladvocates-increasing-competitive-solicitation-in-transmission.pdf
- Electricity Transmission Competition Coalition and CPUC Initial Comments on NOPR
- MA-AGO-NOPR-Reply-Comments
- R Street Reply Comments on FERC ANOPR
- Competition for Electric Transmission Projects (mit.edu)
- Cost Savings Offered by Competition in Electric Transmission: Experience to Date and Potential Value for Electricity Consumers - Brattle
- Report by Brattle Economists Discusses the Benefits of Competitive Transmission – Brattle
- Response to Concentric Energy Advisors' Report on Competitive Transmission – Brattle
- How ROFR Laws Increase Electric Transmission Costs in Midwestern States - R Street Institute
- Counterflow: Say It Ain't So, Joe - RTO Insider
- R Street Responds: Aii Report Does Not Rebuke the Merits of Electric Transmission Competition - R Street Institute

Making the case against competition in electric transmission:

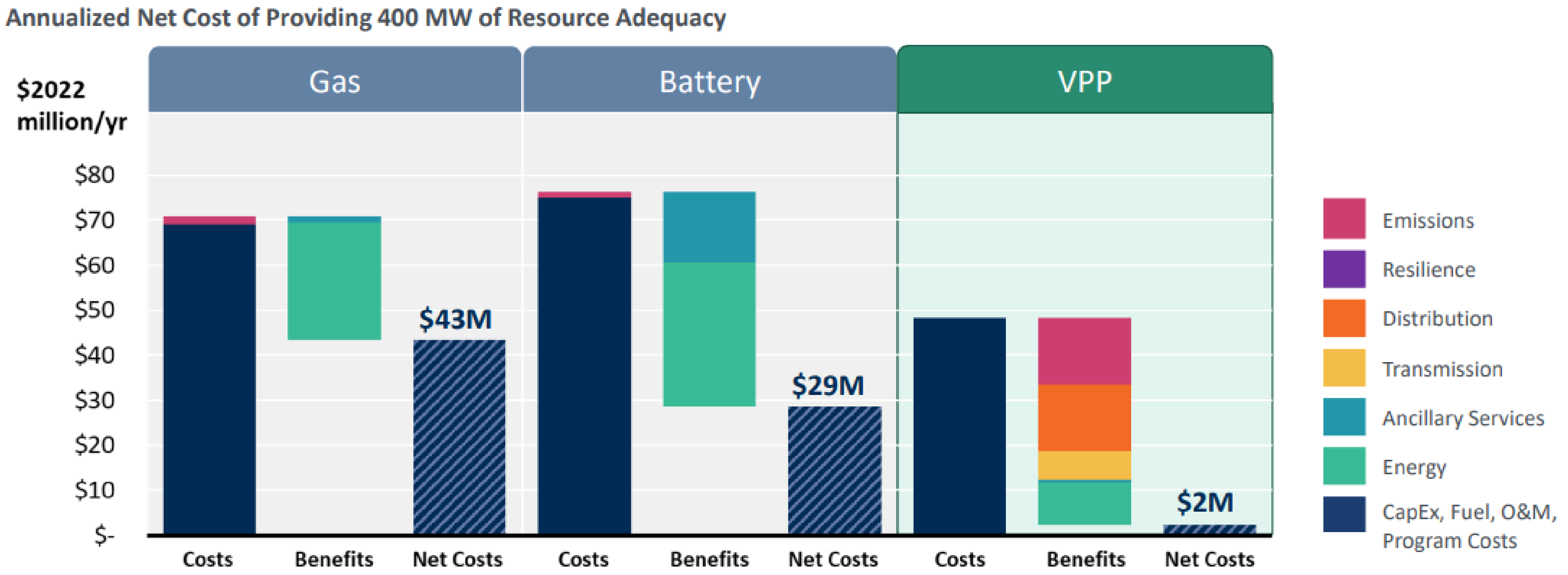
- Building-New-Critical-Infrastructure.-No-Time-to-Waste.pdf (aii.org)
- WIRES Quarterly Newsletter April 2024
- An-Updated-Examination-of-FERC-Order-1000-Projects.pdf (ceadvisors.com)
- DATA supplemental NOPR comments
- Competitive Transmission: Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits (ceadvisors.com)

Efficiency and demand flexibility to reduce G+T+D costs

Electrification is quickly increasing electricity demand and system peak loads … <u>and</u> offers substantial opportunities to more cost-effectively meet system needs

- Most electrification demand is <u>flexible</u> (suitable for Virtual Power Plants or VPPs)
  - Examples: Electric vehicles (including V2G), building HVAC, thermal storage, solar+storage, data centers, H2
- Many electrification loads and distributed energy resources (DERs) are <u>highly controllable</u>
  - RMI: 60 GW of <u>dispatchable</u> VPPs can be developed by 2030 to provide RA and flexibility/operational reliability

Example: VPPs offer <u>resource adequacy</u> at (1) significantly <u>lower cost</u> and (2) <u>without delays</u> in generator interconnection



Source: Hledik and Peters, Real Reliability: The Value of Virtual Power (Brattle, May 2023)

Significant barriers to planning new interregional transmission

A. Leadership, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policy makers to prioritize creating effective 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

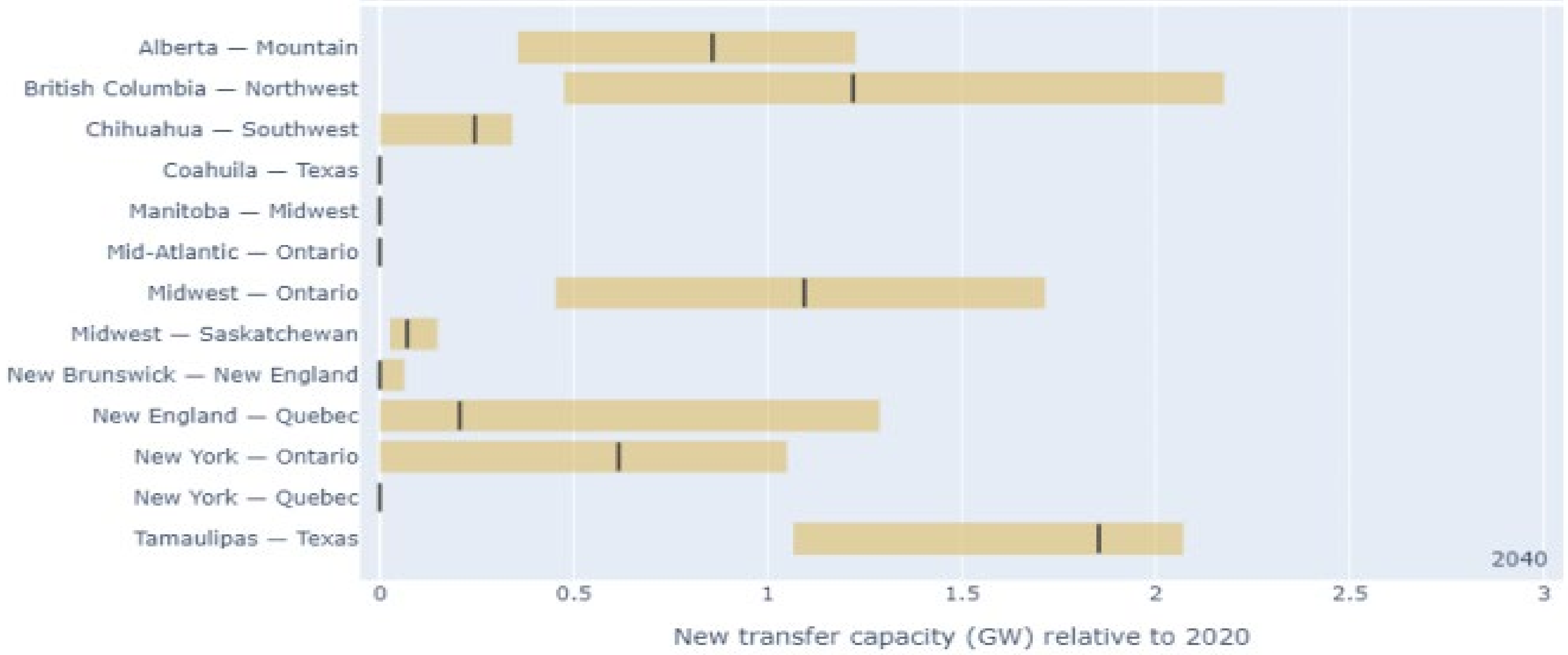
Source: Appendix A of A Roadmap to Improved Interregional Transmission Planning, November 30, 2021. Based on interviews with 18 organizations representing state and federal policy makers, state and federal regulators, transmission planners, transmission developers, industry groups, environmental groups, and large customers.

Additional transmission between the US and Canada would reduce costs and maintain reliability

As more weather-dependent renewable resources are added to the grid, the geographic scope of the grid needs to expand beyond the size of large weather systems!

This will make expanding inter-provincial and international transmission increasingly beneficial!

Example: Cost-effective US-Canadian Transmission Expansion for moderate renewable generation and load growth scenarios (2040)



Source: US DOE, National Transmission Needs Study (Draft), Feb 2023, Table 8, Figure VI-7.

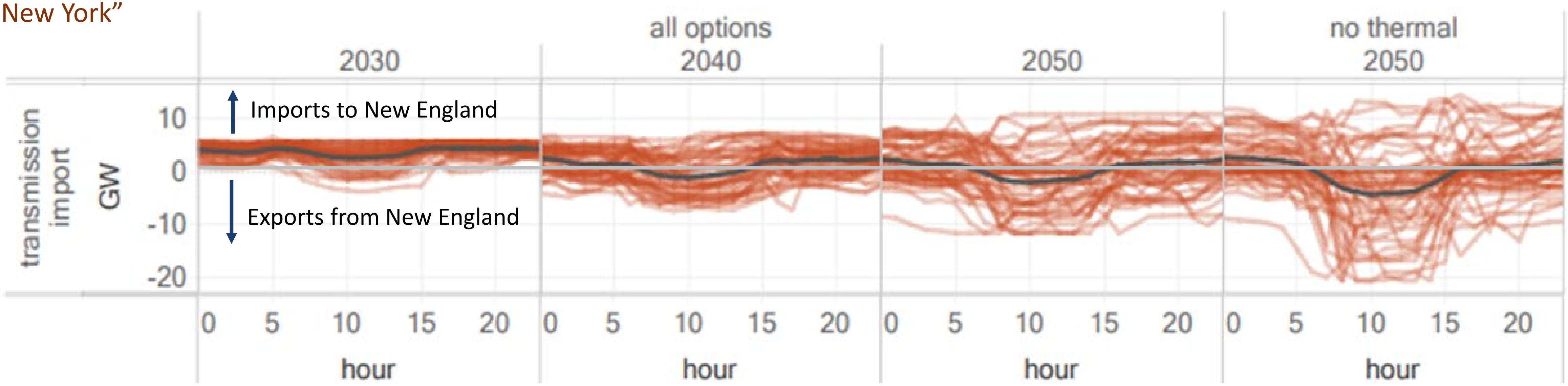
Additional transmission between the US and Canada will be beneficial … and increasingly be used bi-directionally

<u>Example</u>: MA Decarbonization Pathway Study shows additional transmission to Quebec is needed and bidirectional used starting in 2030:

“the Quebec hydro system in effect acts as a form of seasonal energy storage, with energy exported to Quebec during many hours to serve Quebec loads, and with imports from Quebec in other hours to serve loads in New England and New York”

Cost effective new transmission by 2050:

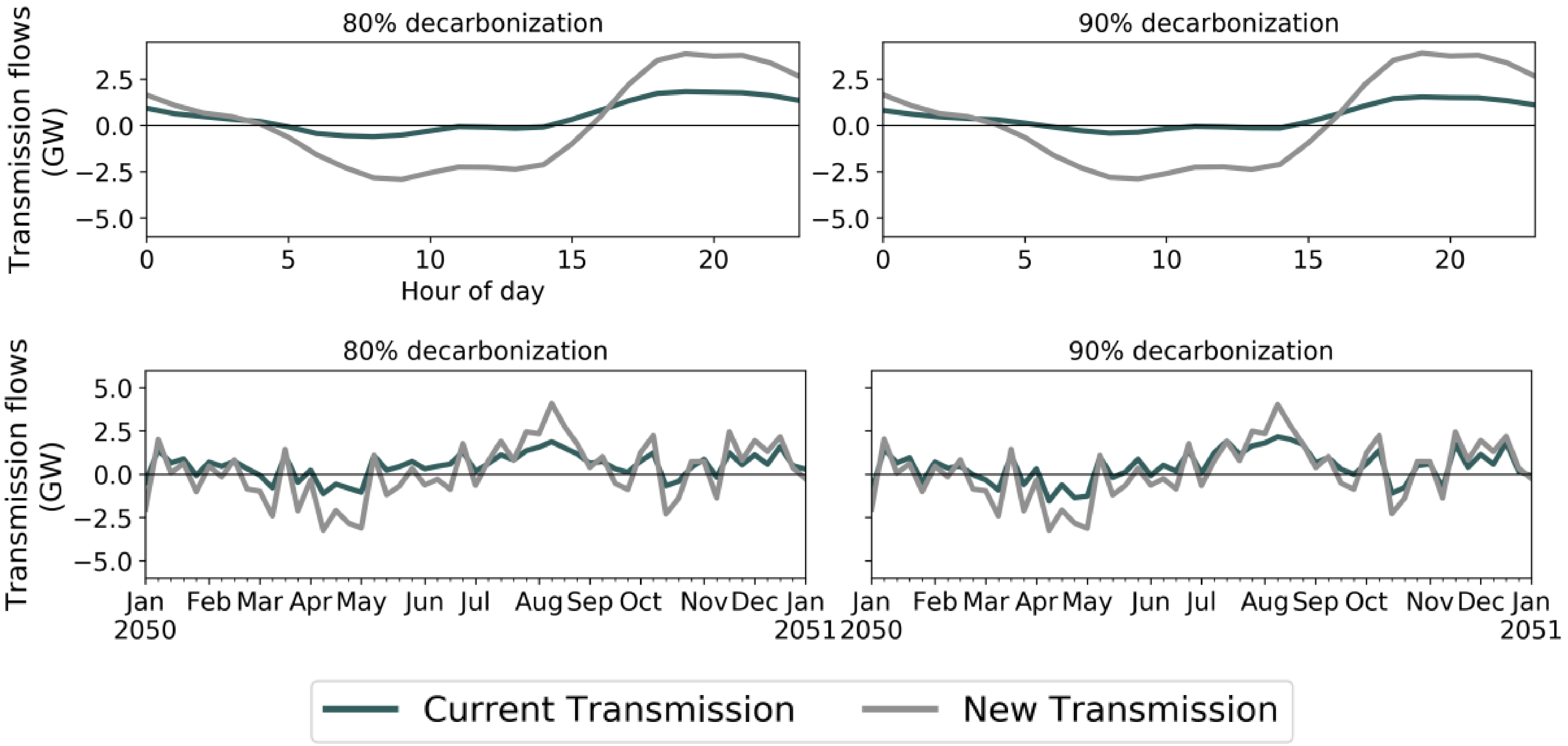
Zone from	Zone to	no thermal	regional coordination	limited efficiency	100% renewable primary	all options	der breakthrough	pipeline gas	constrained offshore wind
Quebec	Maine	2	1.2	1.1	0.9	0.6	0.6	0.6	0.9
Quebec	Massachusetts	4.3	4.8	3.7	3.3	2.7	2.8	3.1	3.9
Quebec	New Brunswick	0	0	0	0	0	0	0	0
Quebec	New York	6.8	6.8	6.8	4.7	4.4	4.2	5.6	3.8
Quebec	Vermont	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8



Source: MA Decarbonization Pathways Study, Dec 2020, Table 8, Figure 27.

MIT Study: Additional transmission between the Northeastern US and Canada will be cost effective and used bi-directionally

MIT similarly found that decarbonization of the electric grid in the Northeastern US will increase the need for transmission capacity and bidirectional power flows.



Source: Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower, MIT, Feb 2020.

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

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Grid Strategies:
Rob Gramlich
Michael Goggin
Jay Caspary
Jesse Schneider

OCTOBER 2021

Brattle
GRID STRATEGIES LLC

Summarizes proven approaches to quantifying various benefits

Brattle Group Publications on Transmission

Gramlich, Hagerty, et al., Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid, Grid Strategy and Brattle, August 2024.
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Pfeifenberger, How Resources Can Be Added More Quickly and Effectively to PJM's Grid, OPSI Annual Meeting, October 17, 2023.
Pfeifenberger, Bay, et al., The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encourage Interregional Transmission, October 2023.
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Pfeifenberger et al., New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report, October 26, 2022.
Pfeifenberger, DeLosa III, Transmission Planning for a Changing Generation Mix, OPSI 2022 Annual Meeting, October 18, 2022.
Pfeifenberger, Promoting Efficient Investment in Offshore Wind Transmission, DOE-BOEM Atlantic Offshore Wind Transmission Economics & Policy Workshop, August 16, 2022.
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.
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.
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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
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- Valuation
- White Collar Investigations & Litigation

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