Transmission Cost Allocation for Order 1920 Compliance

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NARUC-NASEO-DOE Webinar on FERC Order 1920: Taking Action on Transmission Planning and Cost Allocation

December 6, 2024

Brattle

Summary of Order 1920 (1920-A) cost allocation provisions*

Ex ante (default) methodology for long-term regional transmission cost allocation:

- Ex ante cost allocation method is meant to provide certainty before transmission projects are built
- Transmission providers must engage with states to develop (over 6-12 months) one or more *ex ante* "default" cost allocation methods that apply to long-term regional transmission facilities
- Proposed cost allocations must distribute costs in a manner that is at least roughly equal with estimated benefits
- Default allocation cannot be based on project types (such as reliability, economic, or public policy requirements)
- Transmission providers must involve states in any future changes to cost allocations; must file both their own and the states' cost allocation proposal, if different

State Agreement Process (permitted but not required):

- If implemented, gives states the opportunity to propose (prior to or within 6 months of project selection) an alternative cost allocation method for specific long-term regional transmission facilities
- Offers flexibility to customize processes and requirements. However, if no cost allocation agreement is reached, the default cost allocation will be used

Voluntary Funding Opportunities (required):

- States and interconnection customers must be provided with the opportunity to voluntarily fund the cost (or a portion) of a facility that otherwise would not meet the planning entity's selection criteria

* For a more detailed overview, see Order 1920 Explainer and Order 1920-A Summary

Agreeing on cost-allocation is critical, challenging, and possible

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

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

- Most TOs strongly prefer recovering costs associated with their own ratebase
- Policy makers reluctant to share costs of distant projects in other states

Even harder: share costs of economic or public-policy projects:

- Planning challenged by often fundamentally different views of the future
  - State policy makers may disagree on key planning assumptions, such as fuel prices, technology options, and public policy objectives (e.g., environmental policies or load growth from electrification and economic development support)
- Large regional projects for environmental or economic development (e.g., data center) policies pit states that have them (often with major population centers) against states that don't (often more remote areas)
- Reluctance to pay for transmission that facilitates out-of-state generation investments with few in-state jobs

Hardest: cost allocation for interregional projects; few models and little experience because no significant interregional projects have been planned in the last decade

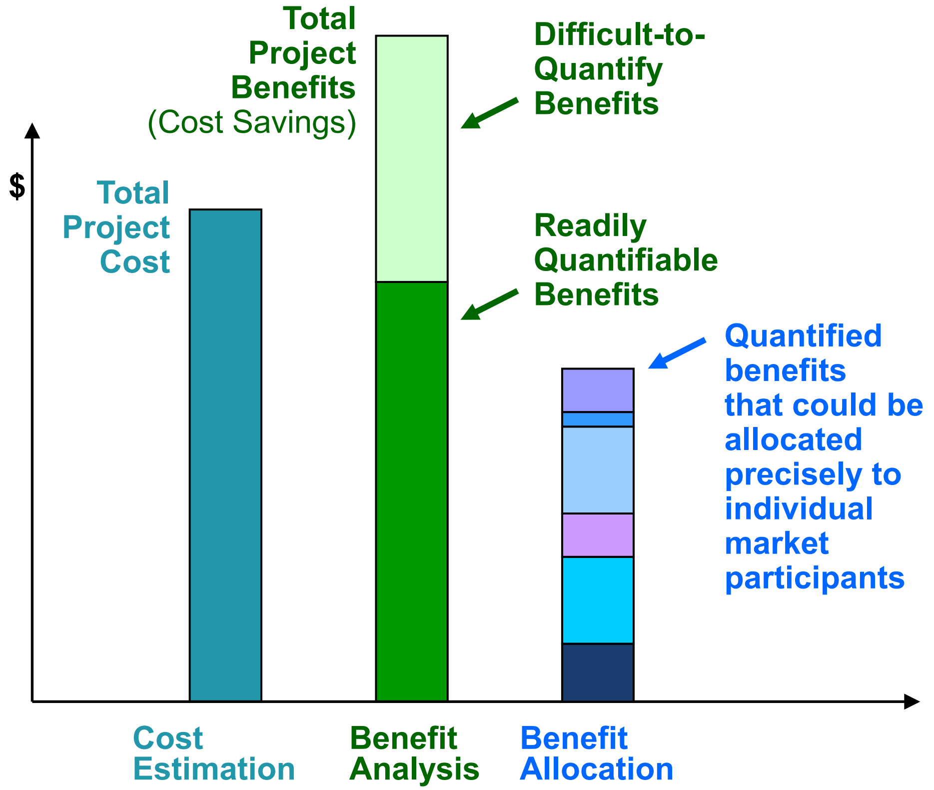
Basic cost allocation and recovery mechanisms

1) **License Plate:** each utility "locally" recovers the costs of its transmission investments (usually located within its footprint). Example: used for all MISO "reliability" and all RTOs' "local" projects
2) **Beneficiary Pays:** various formulas that allocate costs of transmission investments to individual Transmission Owners (TOs) that benefit from a project, even if the project is not owned by the beneficiaries. TOs then recover allocated costs in their License Plate tariffs from own customers
3) **Postage Stamps:** transmission costs are recovered uniformly from all loads in a defined market area
   - RTO-wide examples: ERCOT, >200kV in CAISO, >100kV in ISO-NE, Multi-Value Projects in MISO
   - Highway/Byway in SPP: postage stamp for all projects >300 kV; 1/3 postage stamp and 2/3 license plate for projects 100-300 kV; 100% license plate for projects below 100 kV
   - Often implemented by first allocated costs to TOs (e.g., on a MW or MWh load ratio share), who then recover these allocated costs in their license plate tariffs
4) **Direct Assignment/Participant Funding:** transmission costs (e.g. associated with generator interconnection or transmission service requests) are assigned to requesting entity
   - Innovative variance: CAISO's Tehachapi LCRI (up-front shared funding, later charged back to generators)
5) **Merchant Cost Recovery:** the project sponsors recover costs outside regulated tariffs through negotiated rates with individual long-term transmission service customers
6) **Co-ownership:** benefitting transmission owners co-own the facility (each recovering costs through rate base treatment); one operator, shared transmission rights (e.g., CAPX 2020; often used in WECC)

Recommendation: Clearly separate benefit-cost analysis for selecting projects from cost-allocation of approved portfolios

Recommend 2-step approach (as contemplated in Order 1920):

1. Determine whether projects are beneficial overall, quantifying a broad set of benefits
   - Without quantifying most benefits, many desirable projects (or synergistic portfolios) will be rejected
   - Benefits that can be allocated precisely may only be a subset of total benefits
   - Avoid temptation to understate benefits in effort to reduce cost allocation to individual study participants
2. Evaluate how the cost of a broad portfolio of beneficial projects should be allocated based on their joint distribution of benefits
   - Reduces conflict: a broad set of benefits quantified for a portfolio of projects tends to be more stable over time and be distributed more uniformly



Portfolio-based cost allocation offers significant advantages over project-by-project allocations

Orders 1000 and 1920 do not require that the cost of each project is allocated precisely based on its benefits … as long as the cost allocation for a portfolio of projects is "roughly commensurate" with overall benefits received.

Even postage stamp (load-ratio share) allocation is appropriate and acceptable if:

- All customers tend to benefit from class or group of facilities
- Distribution of benefits is likely to vary (but "average out") across the region and long life of facilities

Portfolio-based cost allocations are less controversial and easier to implement

- **Portfolio-wide benefits tend to be more even distributed and more stable over time**
- **Only one cost allocation analysis needed for portfolio** (vs. many analyses for many projects)

Examples of portfolio-based cost allocations:

- SPP Highway-Byway (designed by RSC): Periodic review to ensure combined benefits (of all approved projects) are roughly commensurate with allocated costs (for all projects)
- MISO MVPs (with OMS input): Benefits of entire portfolio compared with allocated costs for each zone
- CAISO and ISO-NE: Postage stamp above 200kV and 100kV (without quantifying distribution of benefits)

Recommendation: Allocate costs "roughly commensurate" with (but not formulaically based on) quantified benefits

Cost allocations that are formulaically based on quantified benefits are inherently contentious and counter productive:

- Quantified values of benefit metrics depend on analytical approach and assumptions
- Benefits vary across scenarios and can change quickly as current and projected market conditions change
- Market participants question benefit metrics, approaches, and assumptions that yield large allocations to them
- Tends to yield overly "conservative" (understated) benefit estimates … such that even very valuable transmission projects cannot meet the required B-C thresholds

Formulaic benefits-based allocations for individual projects yield the most contentious and often unexpected outcomes

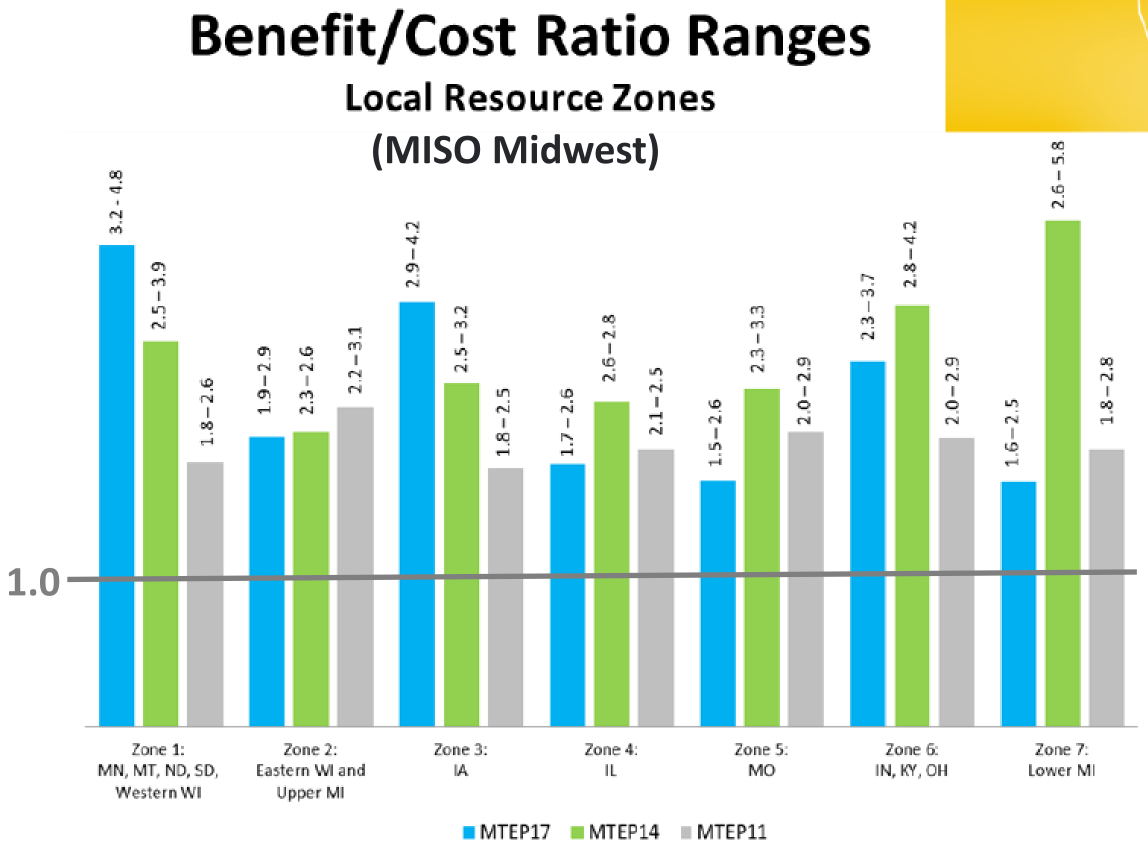
- Benefits and utilization of individual transmission projects change significantly over time (with differences load growth, generation retirements and additions, other transmission investments, and changes in fuel costs)
- Formulaic allocations based on individual benefit metrics (incl. physical power flows) have a track record of creating unexpected and contentious outcomes (e.g., in PJM)

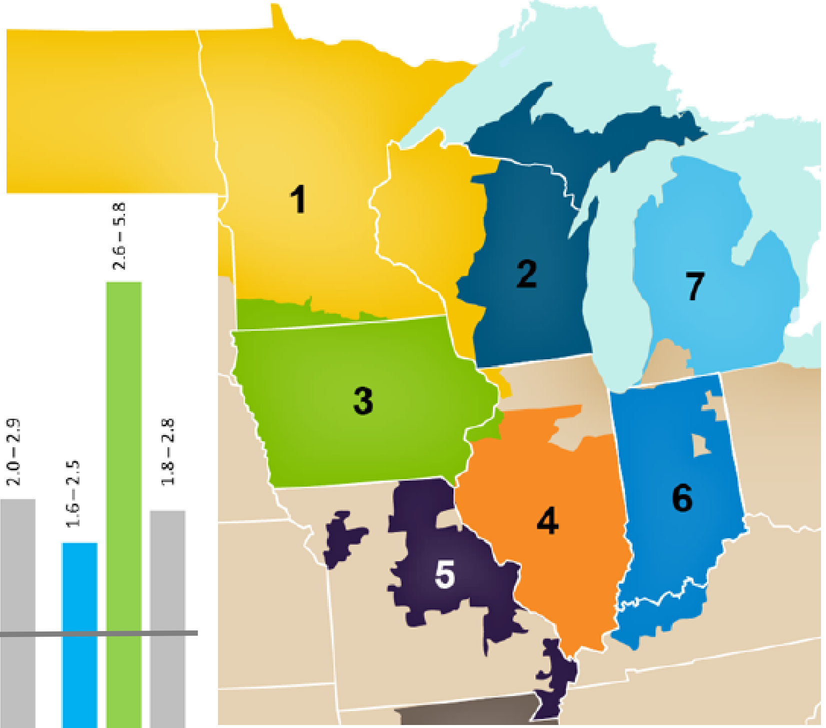
Simple cost allocations that are roughly commensurate with broad set of benefits quantified for a portfolio of transmission projects (such as SPP's highway-byway or MISO's MVP approach) tend to be less contentious and have proven to be longer-lasting

Example: MISO's MVP subregional postage stamp – total portfolio benefits significantly exceed allocated costs in all zones

Benefits of MISO's Multi-Value-Project Portfolios are roughly commensurate with allocated cost (using postage-stamp for Midwest Subregion)

- MISO quantifies multiple economic benefits (including reliability and public benefits)





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

- Total costs of first MVP portfolio increased from $5.6 to $6.7 billion, but benefits grew even more!

- **B-C ratios for zones are not identical nor constant over time**
- **Zonal benefits exceed allocated costs everywhere (with B-C ratios of 1.5 to 3.2 in every zone)**

Example: SPP's experience – more uniform total benefits for large ITP portfolio evaluated with multiple benefits metrics

SPP's Regional Cost Allocation Reviews (RCAR) showed (1) B-C Ratios of SPP's ITP Portfolio has grown over time and (2) provides members with total benefits that exceeds their allocated costs in most cases

- Was done every few years for all ITP projects approved to date
- Evaluation of entire ITP portfolio makes quantification of multiple benefits metrics possible

Metric	RCAR I (2013$m)	RCAR II (2016$m)
APC Savings	$3,020	$8,974
Assumed Benefit of Mandated Reliability Projects	$2,475	$5,759
Mitigation of Transmission Outage Costs	$340	$1,014
Capacity Savings from Reduced On-Peak Losses	$155	$743
Increased Wheeling Through and Out Revenues	Not Monetized	$641
Marginal Energy Losses Benefits	Not Monetized	$427
Avoided or Delayed Reliability Projects	$97	$41
Benefit from Meeting Public Policy Goals	$296	$0
Reduced Cost of Extreme Events	Not Monetized	Not Monetized
Reduced Loss of Load Probability	Not Monetized	Not Monetized
Capital Savings from Reduced Minimum Required Margin	Not Monetized	Not Monetized
Total Benefits (PV of 40-yr Benefits for 2015-2054)	$6,383	$17,599
Total Portfolio Cost (PV of 40-yr ATRR)	$4,581	$7,180

Estimated 40-year Present Value of Benefit Metrics and Costs (2016 $million)

	Present Value of 40-yr Benefits for the 2015-2054 Period (2016 $million)												PV of 40-yr ATRRs (2016 $million)			
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-Peak Losses	Mitigation of Trans-mission Outage Costs	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Reduced Cost of Extreme Events	Reduced Loss of Load Probability	Capital Savings from Reduced Minimum Required Margin	Total Benefits	Before PtP and MISO Revenue Offset	PtP and MISO Revenue Offset	After PtP and MISO Revenue Offset	Benefit/ Cost Ratio
AEP	$1,216	$20	$87	$207	$965	$0	$133	$59				$2,686	$1,654	$121	$1,533	1.75
CUS	-$33	$0	$0	$14	$53	$0	$5	$2				$42	$76	$5	$71	0.59
EDE	-$25	$0	$0	$24	$83	$0	$12	$0				$95	$126	$9	$117	0.81
GMO	$174	$1	$3	$38	$180	$0	$19	-$2				$412	$207	$15	$192	2.15
GRDA	$82	$0	$1	$19	$70	$0	$13	-$6				$179	$114	$8	$106	1.68
KCPL	$642	$1	$6	$76	$308	$0	$37	$51				$1,122	$407	$29	$378	2.97
LES	$115	$0	$1	$19	$64	$0	$8	$15				$223	$106	$8	$98	2.27
MIDW	$76	$0	$11	$8	$93	$0	$5	-$3				$190	$71	$5	$66	2.89
MKEC	$60	$0	$17	$13	$171	$0	$14	$30		Not Monetized		$306	$259	$20	$239	1.28
NPPD	$158	$1	$53	$58	$275	$0	$38	-$9				$574	$404	$29	$375	1.53
OGE	$1,428	$2	$65	$131	$635	$0	$66	-$64				$2,262	$838	$60	$777	2.91
OPPD	$24	$1	$3	$48	$150	$0	$23	$9				$257	$320	$23	$297	0.87
SEPC	$83	$0	$12	$9	$159	$0	$8	$11				$283	$82	$6	$76	3.73
SPS	$3,537	$12	$357	$115	$1,024	$0	$90	-$13				$5,122	$1,402	$102	$1,301	3.94
UMZ	$281	$1	$47	$96	$595	$0	$55	$191				$1,266	$397	$45	$352	3.60
WFEC	$159	$0	$77	$34	$222	$0	$20	$56				$568	$295	$21	$274	2.08
WR	$996	$1	$5	$105	$710	$0	$94	$100				$2,011	$1,002	$73	$930	2.16
TOTAL	$8,974	$41	$743	$1,014	$5,759	$0	$641	$427				$17,599	$7,760	$579	$7,180	2.45

Source: https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf

Example: Cost allocation alternatives developed in 2010 by MISO and OMS for $29 billion transmission overlay

MISO analyzed for OMS cost allocation options for projects identified in the Regional Generation Outlet Study (RGOS). OMS proposal used injection-withdrawal approach:

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

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

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

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

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

Summary and Recommendations

Order 1920 create a unique opportunity to focus planning less on near-term reliability and local needs, but proactively on grid infrastructure that provides <u>greater flexibility</u> and <u>higher long-term value</u> at <u>lower system-wide cost</u>

- Recognize that every transmission project offers multiple values
- Lowest-cost transmission is not "least cost" from an overall customer-cost perspective
- Lower-cost/higher-value solutions facilitate cost allocation (by reducing total customer costs)

Improve benefit-cost analyses to yield more cost-effective and less controversial outcomes that facilitate cost allocation:

- Consider <u>broad range of reliability, economic, and public-policy benefits</u> (even beyond 1920 mandates)
- Utilize experience gained in last 2 decades (by CAISO, MISO, SPP, NYISO, and others)
- Reduce divisiveness of <u>cost allocation</u> through broad set of portfolio-based benefits
  - Recognize broad range of benefits → more likely to be evenly distributed and exceed costs
  - Focus on larger portfolios of transmission projects → more uniform distribution of benefits
  - Broad range of benefits for a larger portfolio will also be more stable over time

Use allocations that are <u>roughly commensurate</u> with but <u>not formulaically based</u> on quantified benefits

Thank You!

Additional Slides on Opportunities for Order 1920 Compliance

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!

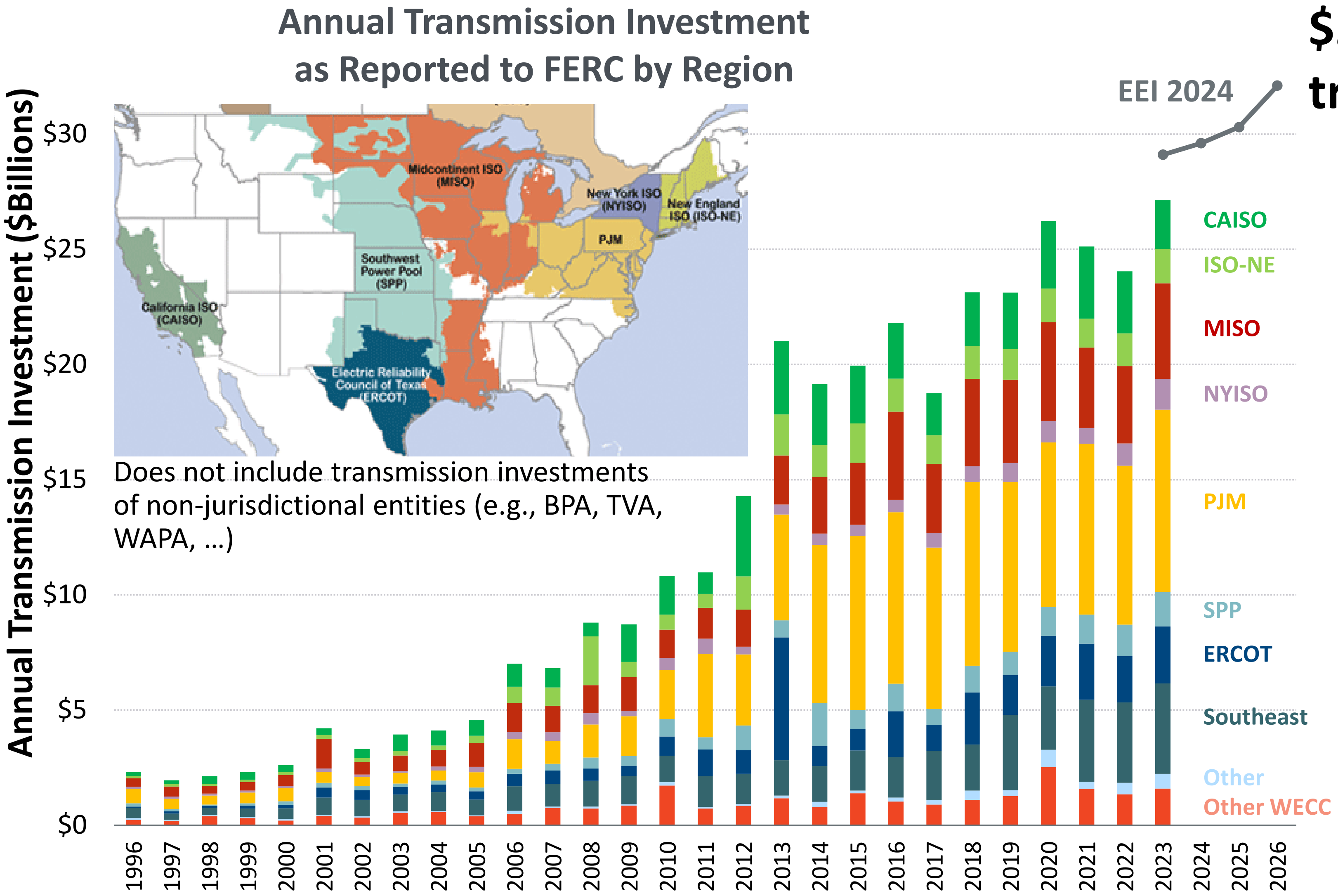
1920 does not require *inter*regional transmission planning

- 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

Annual U.S. Transmission Investments 1996-2023



Sources: The Brattle Group analysis of FERC Form 1 Data; EEI "Historical and Projected Transmission Investment" report.

$25+ billion in annual U.S. transmission investments, but:

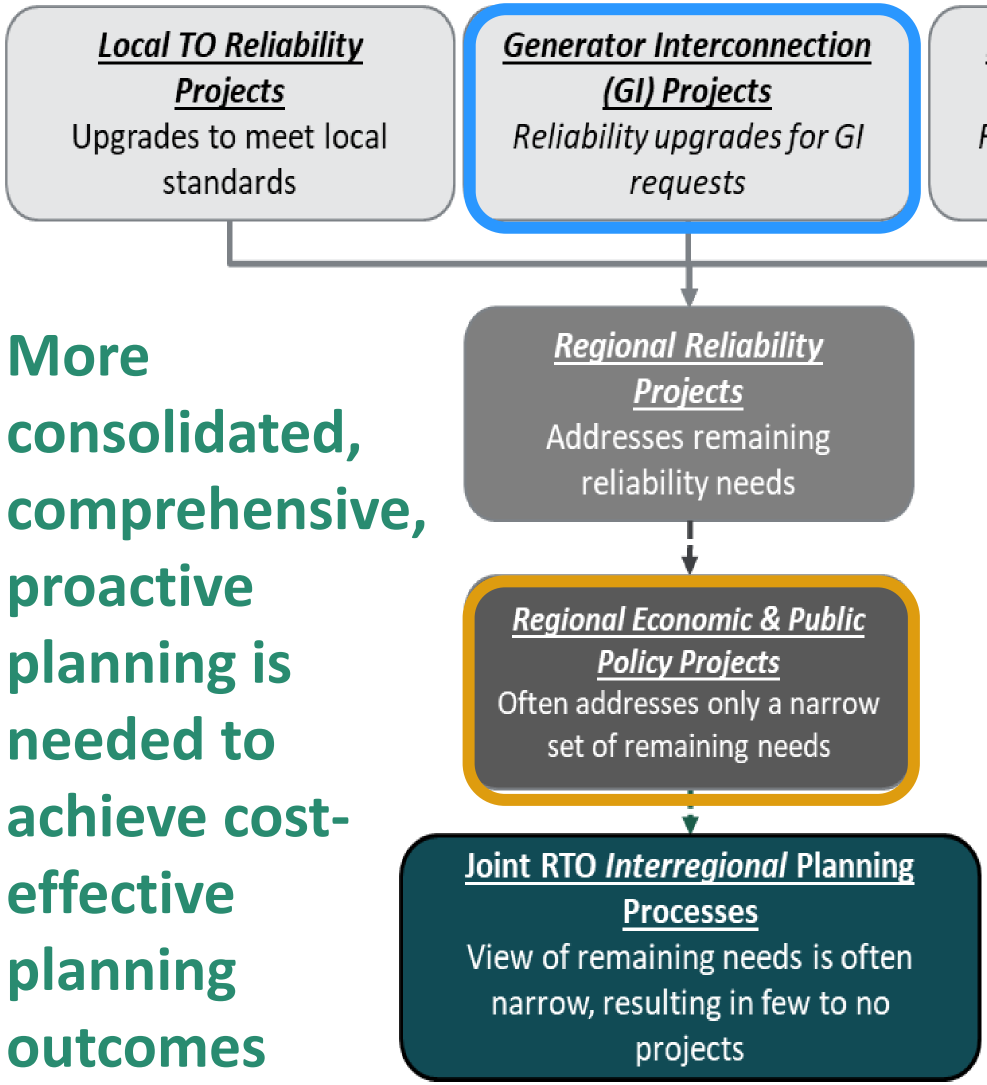
- More than 90% of it justified solely based on reliability needs without benefit-cost analysis
  - About 50% solely based on "local" utility criteria (without going through regional planning processes)
  - The rest justified by regional reliability and generation interconnection needs
- While significant experience with transmission benefit-cost analyses exists, very few projects are justified based on economics to yield overall cost savings
- FERC Order 1920 may change that

Current U.S. Transmission Planning = Higher Total Costs

Current planning processes do not yield the most valuable transmission infrastructure and result in higher overall costs:

- Reactive, reliability-driven planning results in piecemeal, higher-cost transmission solutions
  - For example: PJM generation interconnection studies for 15.5 GW of individual offshore wind plants identified $6.4 billion in onshore transmission upgrades
  - In contrast: A recent PJM study that proactive evaluated onshore upgrade needs for 17 GW of offshore wind (along with 14.5 GW of onshore wind and 45.6 GW of solar) identified only $3.2 billion in onshore upgrades
  - Result: **at least 50% lower costs** if renewable interconnection is planned proactively for the entire region's public policy needs (rather than one project at the time through the generation interconnection process)
- Failure to evaluate multiple benefits of transmission projects does not result in the selection of the highest-value projects that reduce system-wide costs
- Failure to evaluate the full range of plausible futures (to explicitly account for long-term uncertainties), results in higher-cost outcomes when the future deviates from base case planning assumptions, which usually are based on "business-as-usual" or "current-trends" forecast
- Failure to consider interregional transmission solutions result in higher-cost regional and local transmission investments

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

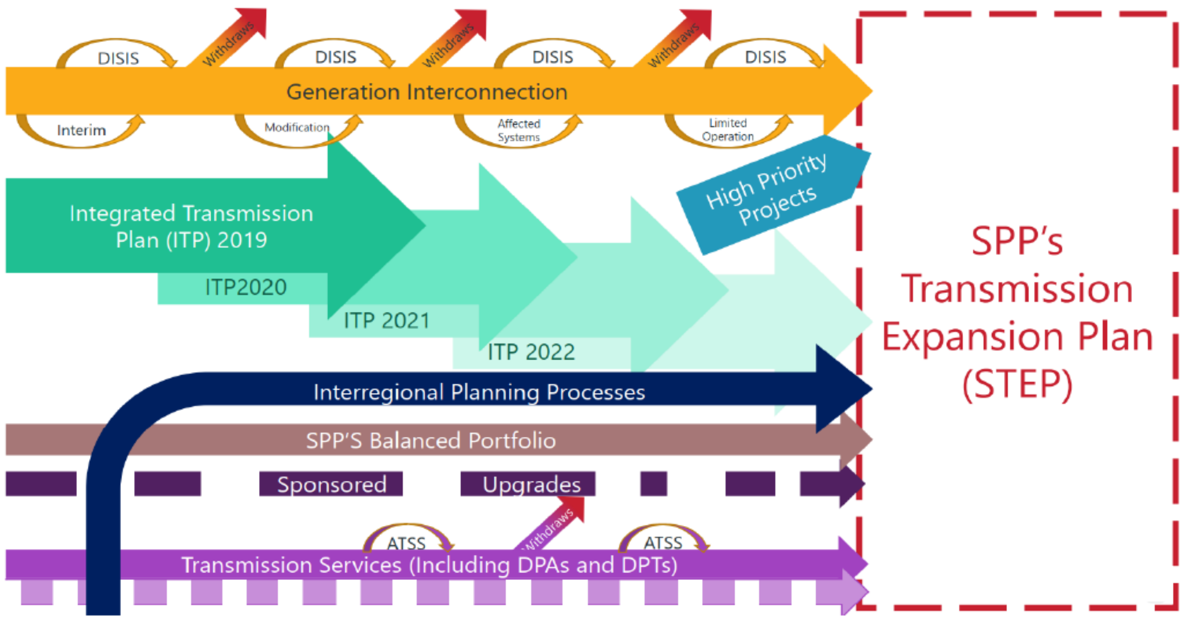
- Essentially no major interregional transmission projects have been planned and built in the last decade
- Numerous national studies show that more interregional transmission is needed to reduce total system costs

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

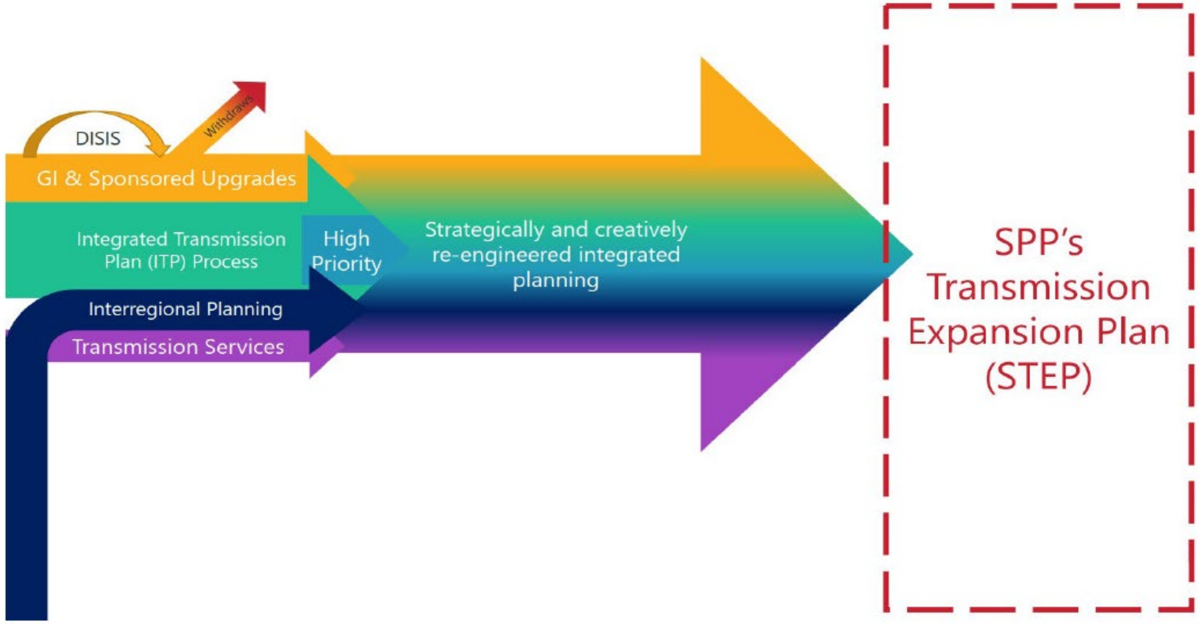
Example: SPP's proposed Consolidated Planning Process (CPP)

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

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 <u>all transmission needs over longer time frames</u> (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 <u>both urgent near-term</u> needs <u>and long-term</u> needs, utilizing <u>scenario-based</u> planning to address long-term uncertainties
3. Reduce the scope of network upgrades triggered by <u>generator interconnection</u> through the proactive planning process (and improve generator interconnection <u>study criteria</u>)
4. Look <u>beyond regional seams</u> to identify more cost-effective <u>interregional</u> solutions to the range of identified transmission needs
5. Rely on <u>advanced transmission technologies</u>, <u>upsizing opportunities</u>, and <u>flexible solutions</u> to address identified needs and enhance the grid
6. Utilize <u>pragmatic cost allocations</u> 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:

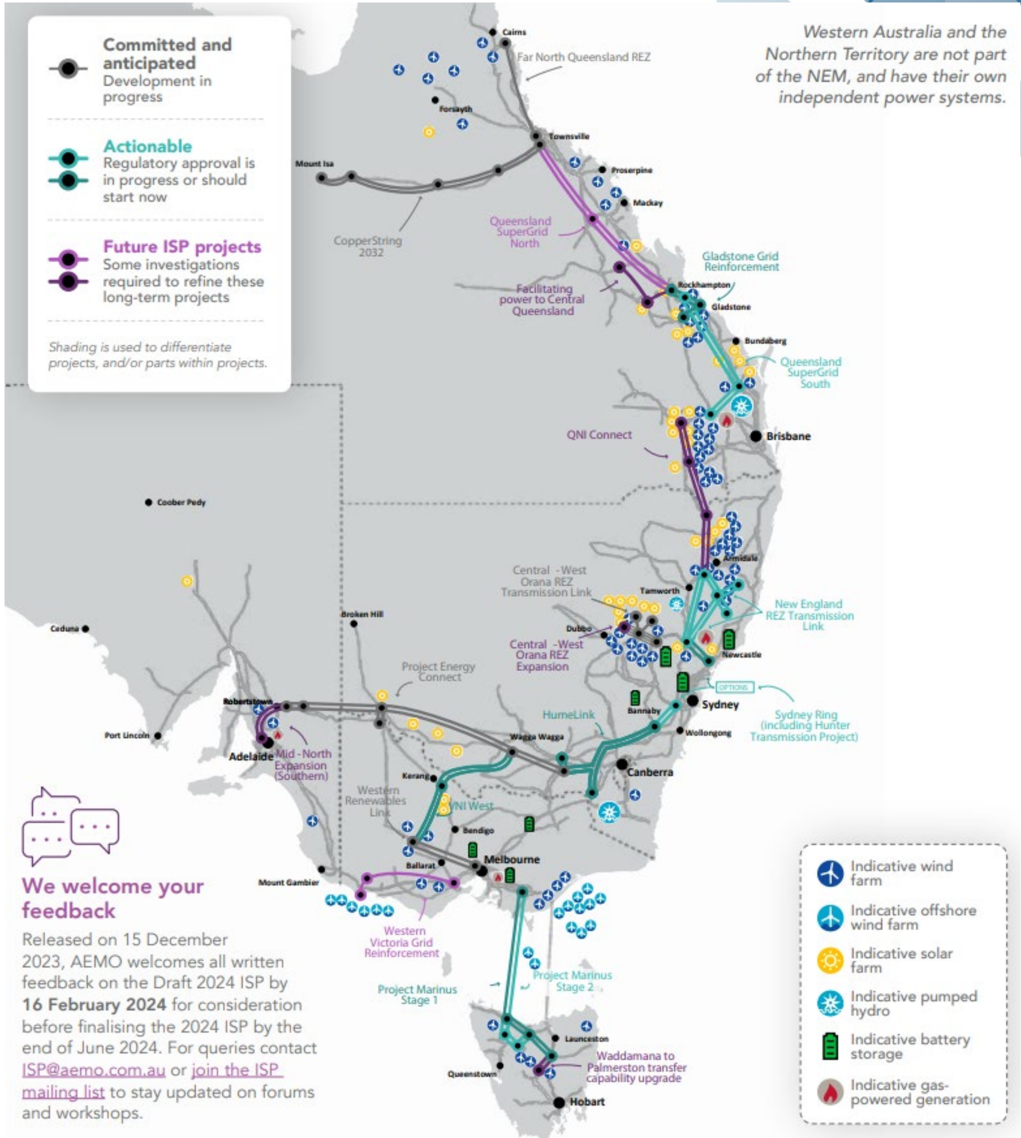
1. Define scenarios of plausible futures by scanning the current reality, trends and forecasts, uncertainties, and important internal and external drivers
2. Develop a series of plans (initiatives, projects, policies, tactics) that work well across multiple scenarios (e.g., by developing **solutions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

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

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

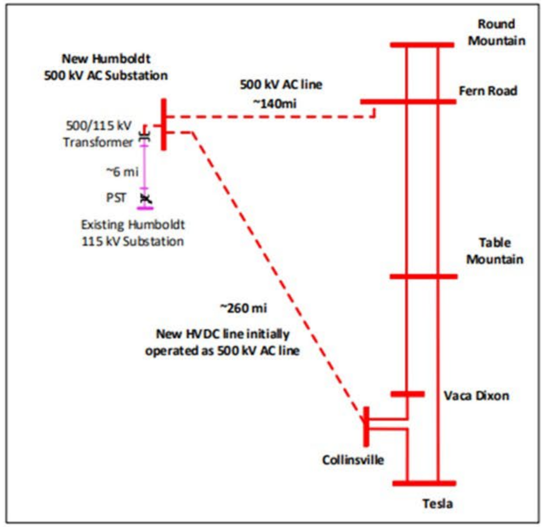
Reduce costs and mitigate risk through more flexible solutions

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:

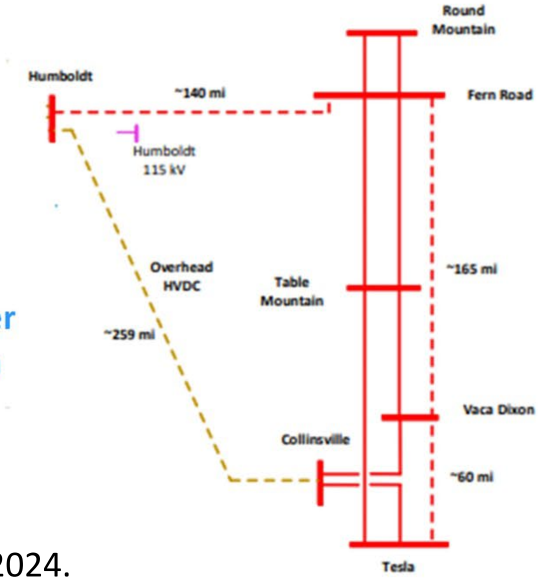
Phase 1: Base Case Plan
(1,607 MW)

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



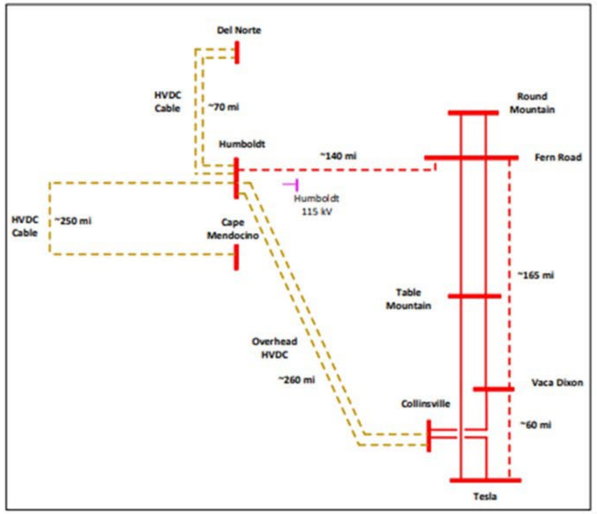
Add DC converter stations to each end of the line

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

See Ensuring Cost Effective Transmission to Support Affordable State Electricity Policies, NARUC Annual Meeting, Nov 13, 2024

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

Examples:

Priority order required by the German “NOVA Principle”

MA CETWG Report: “Loading Order” and ATT/GETs recommendations

2. Upgrades of existing lines

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

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

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

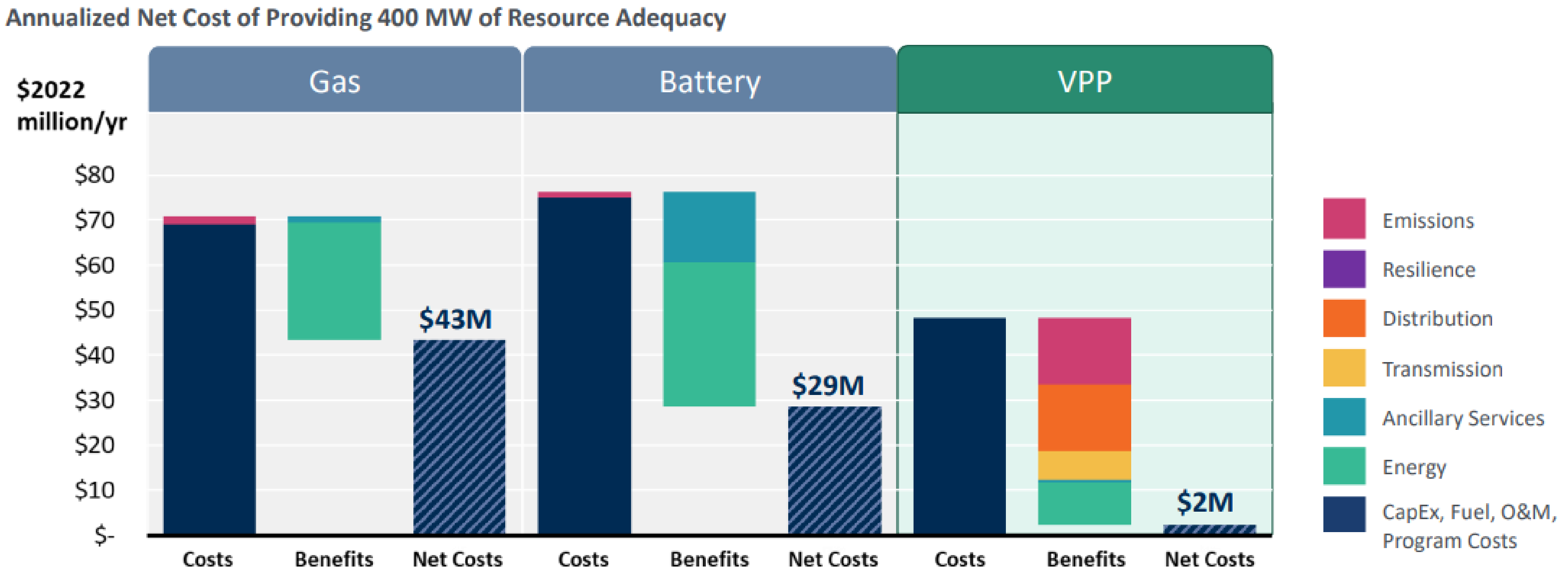
- **Broad-based** performance-based ratemaking (PBR),
    - UK incentives for transmission providers (for both investments and operations) under "RIIO"
    - Australian incentive schemes for networks: efficiency benefits sharing scheme (EBSS), capital expenditure sharing scheme (CESS), and service target performance incentive scheme (STPIS)
- **Project-specific** cost-control and targeted cost-sharing incentives
  - Hard or soft cost caps (with adjustments for some uncontrollable factors)
    - As often included in bids of competitive solicitations (see 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

And let’s not forget …
… 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>
  - <u>RMI</u>: 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, <u>Real Reliability: The Value of Virtual Power</u> (Brattle, May 2023)

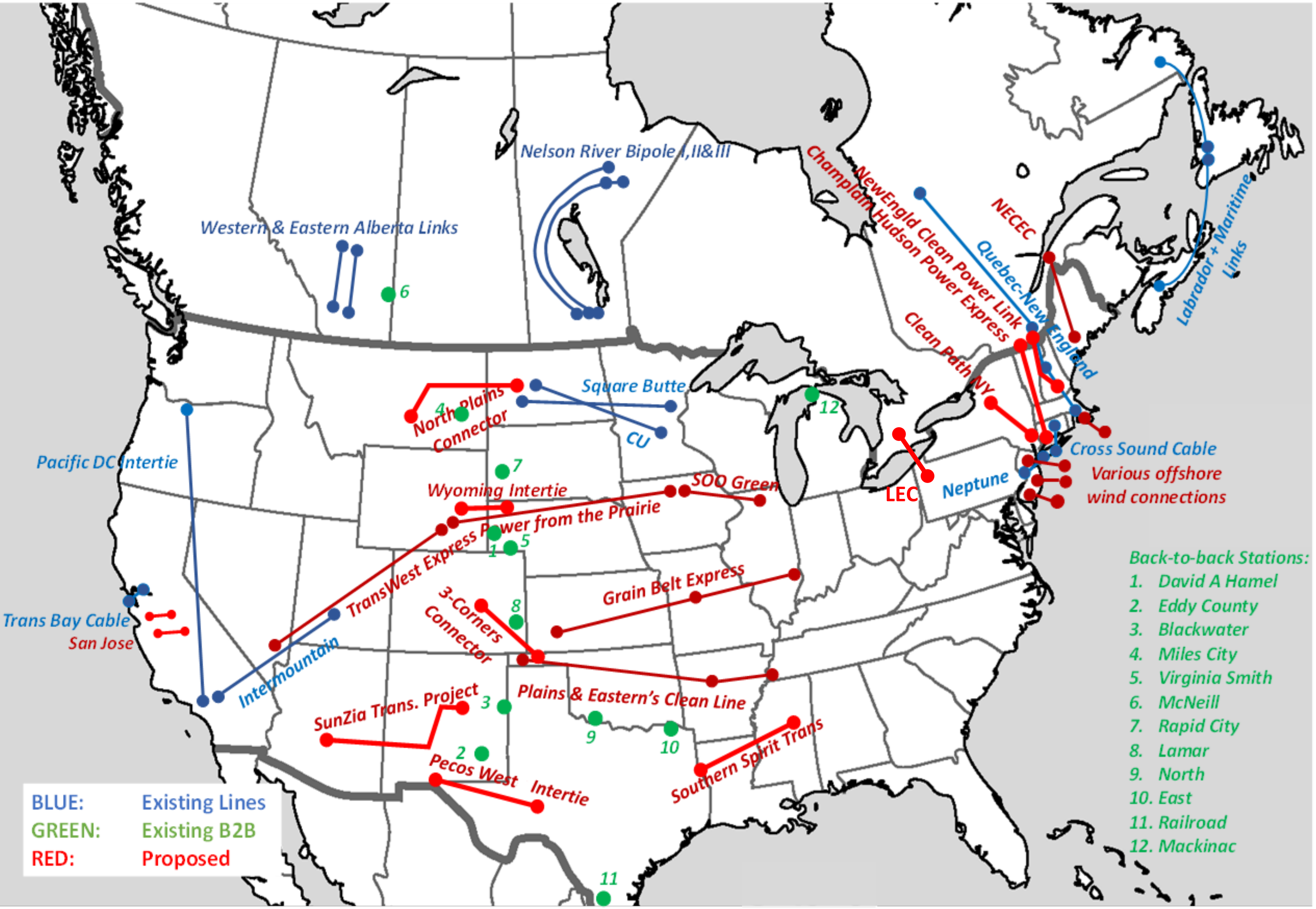
Need: More efficiently plan and utilize interregional transmission

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's "Interregional Transmission Coordination" requirements

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."

Order 1920 compliance can improve interregional planning

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

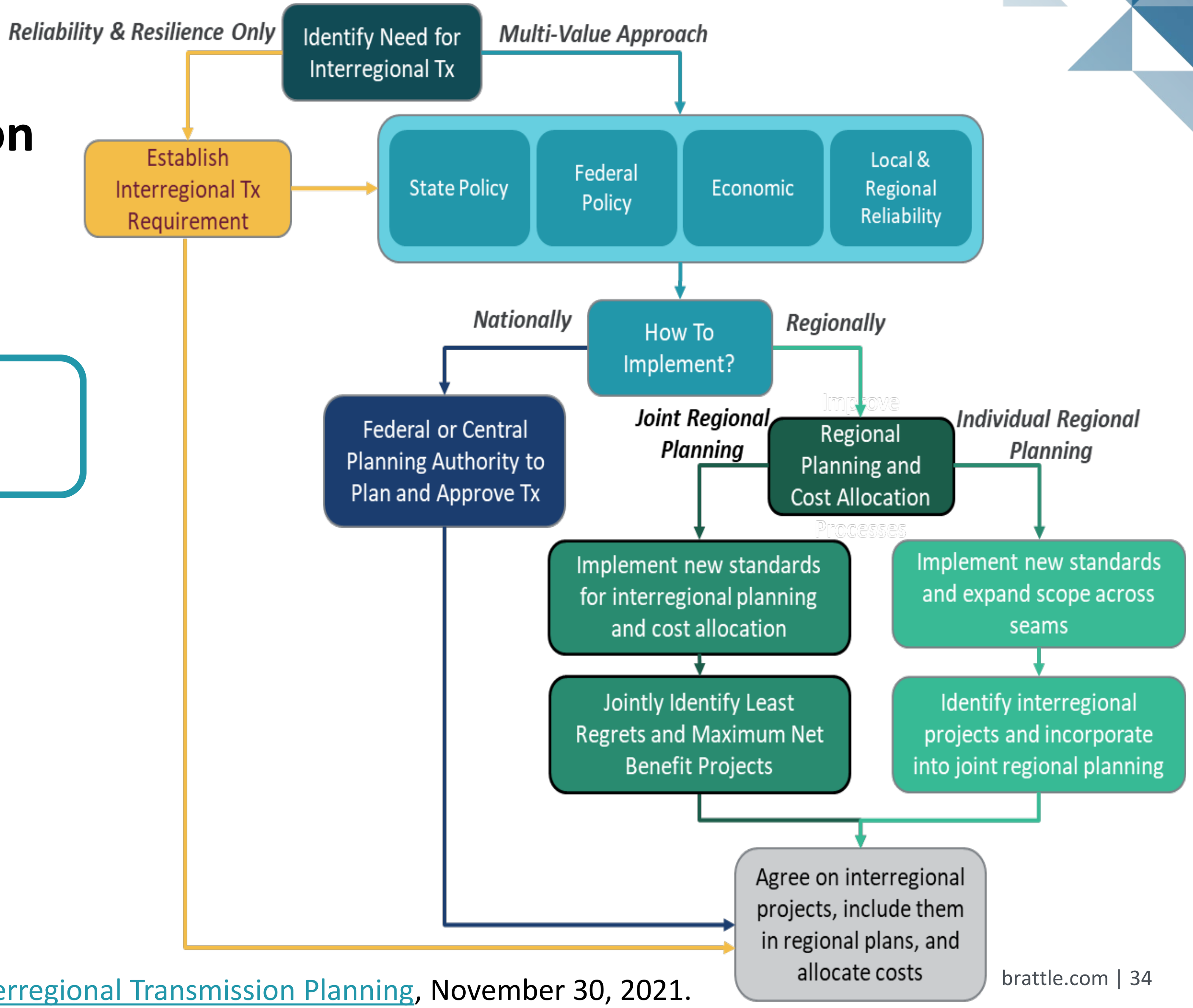


Chart: A Roadmap to Improved Interregional Transmission Planning, November 30, 2021.

What States may propose for 1920 interregional compliance

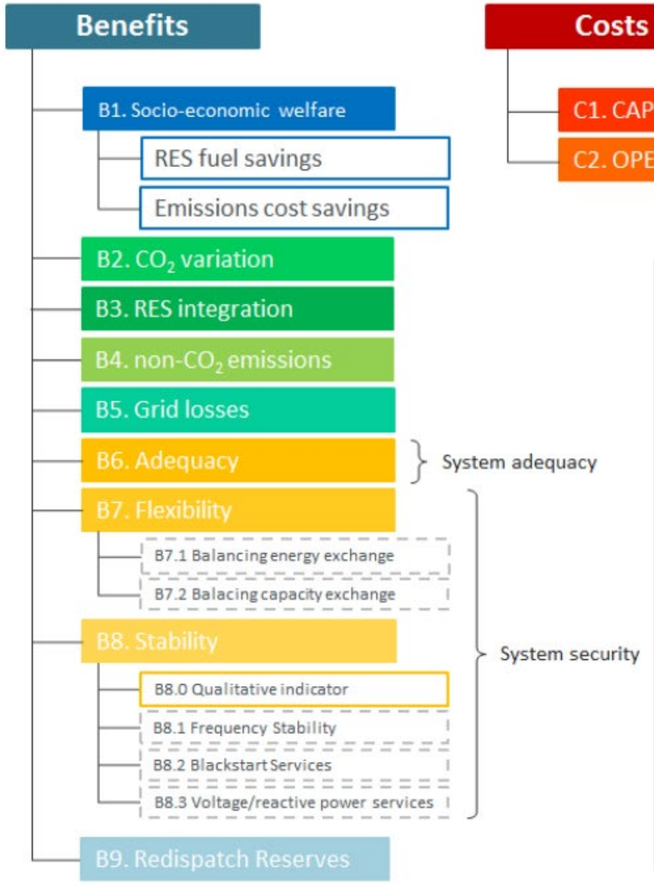
For example: States could propose to make the process under which they and others can propose interregional projects to address identified transmission needs more easily … so that:

- The process would not be limited to RTO-identified regional transmission needs (but allow proposers to explain the needs that their project would address, which may differ by regions)
- Needs are not limited to only the needs identified in the new 1920 long-term planning processes
- The process is not limited to interregional projects that are proposed to both RTOs at the same time, in the same planning cycle (which for 1920 cycles may never fully coincide). If only proposed to one RTO, the "coordination requirement" should mean that the initiating RTO will coordinate with the neighbor
- Benefits evaluated for the proposed interregional project are not limited to the 1920 mandated benefits, but consider all benefits (cost savings, reliability) that the regions may be able to obtain.
- Benefits calculations should not be limited to only the (least-common-denominator) subset of benefits that both RTOs typically calculate … but should instead consider all benefits considered by either one of the RTOs

See benefits and cost allocation principles in Brattle's Interregional Transmission Planning Roadmap Report

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)

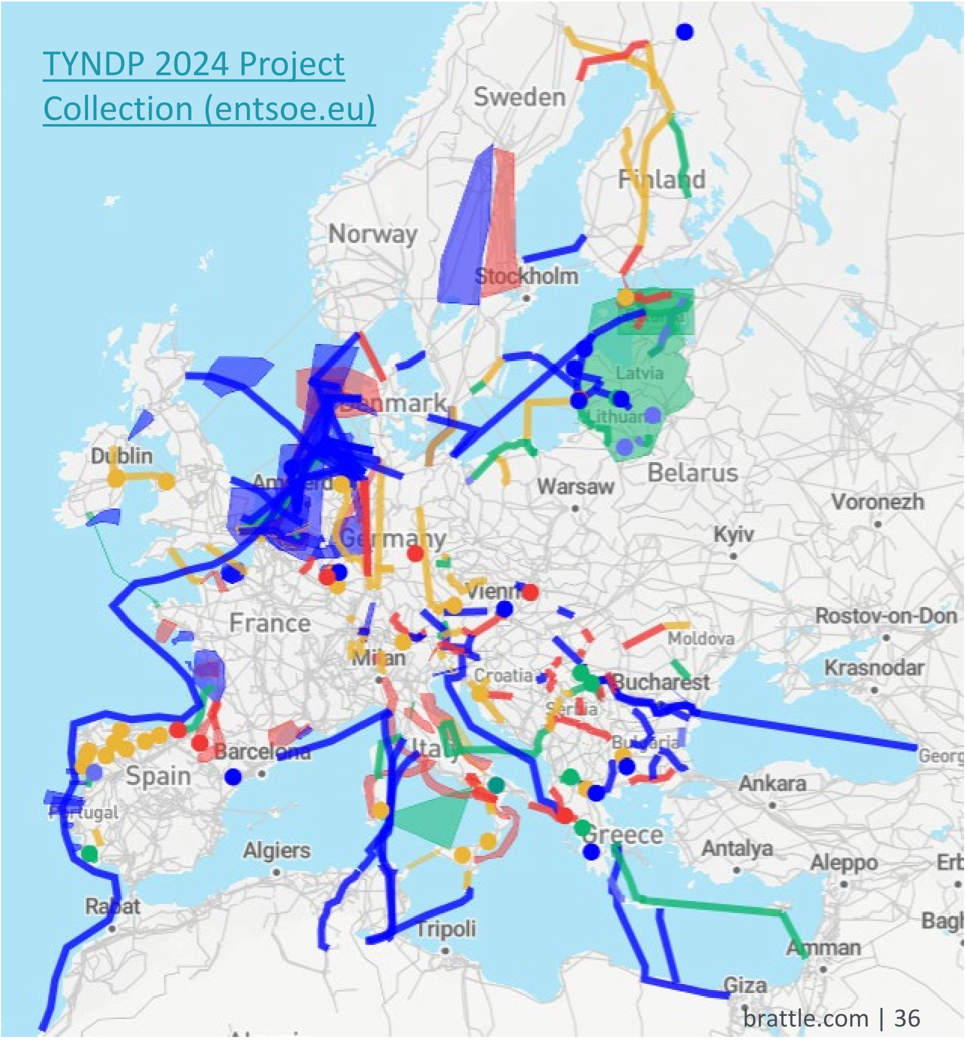


Entso-E Planning and CBA framework

- 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

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

TYNDP 2024 Project Collection (entsoe.eu)



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.

Need: Improving generator interconnection processes

U.S. generator interconnection processes received poor grades. Improving them requires addressing five elements of the interconnection processes:

1. **GI Process and Queue Management:** individual vs. cluster studies, type of studies and contractual agreements, readiness criteria, financial deposits, study and restudy sequences, etc.
2. **GI Scope and "Handoff" to Regional Transmission Planning:** are major ("deep") network upgrades triggered by incremental generation interconnection requests or handled proactively and comprehensively through regional transmission planning?
3. **GI Study Approach and Criteria:** study assumptions, modeling approaches, and specific criteria differ significantly across regions (e.g., firm/non-firm study differences, injection levels studied, are generation redispatch opportunities and "remedial action schemes" considered?)
4. **Selecting Solutions to Address the Identified Criteria Violations:** most regions select only traditional transmission upgrades to address criteria violations; grid-enhancing technologies (such as power-flow-control devices or dynamic line ratings) often are not seriously considered and accepted
5. **Cost Allocation:** most U.S. regions require the interconnecting generator (or group of generators) to pay for all upgrades identified, even though (a) there may be significant regional benefits to loads and other market participants and (b) more cost effective (multi-value) regional solutions may exist

Generator Interconnection: Scorecard assessing 2023 status quo

FIGURE 5 | LBNL Estimate of Interconnection Process for IAs Executed from 2018 to 2022[22]

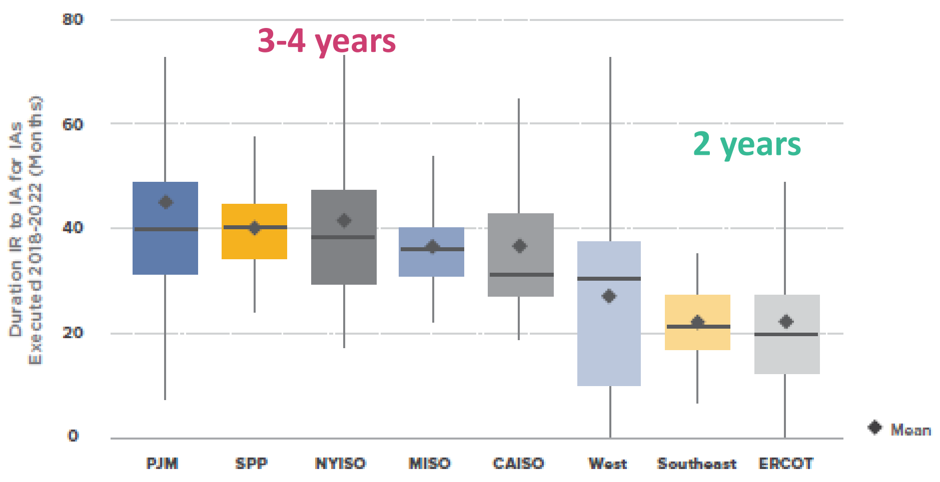


FIGURE ES–1 | Interconnection Agreements Executed Through 2022 for Interconnection Requests Submitted from 2012-2020[2]

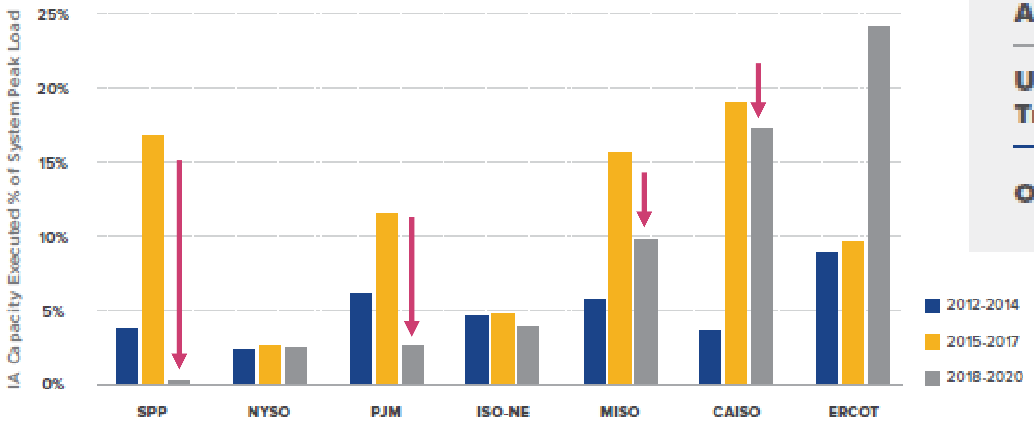


TABLE 1 | Generator Interconnection Scorecard Grades

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Interconnection Process Results	B-	A	C	C	D	D	C-
Pre-queue Information	C+	C	D	C+	C	C	C-
Interconnection Study Process Design	B	A-	C-	D+	B-	F	D
Study Assumptions, Criteria, Replicability	A	A+	C+	D	C+	F	C
Usefulness of Interconnection Alternatives	B+	B	D	B-	D	D	B
Using Regional Transmission Planning	A-	D	D	B	C+	D+	C+
Overall grade	B	B	D+	C-	C-	D-	C-

Source: GridStrategies-Brattle Generator Interconnection Scorecard, Feb 2024.

Generator interconnection: Recommended improvements

FERC sought to address the significant delays and backlogs associated with generator interconnection to the bulk transmission system in Order 2023:

- Adoption of cluster studies for interconnection requests in a given year
- Switch from "first-come, first-served" to "first-ready, first-served"
- Readiness requirements include higher study deposits, 90% site control at time of request, 100% at start of Facilities Study
- Publish heatmaps of available transmission capacity
- Deadlines for completion of interconnection studies
- Consideration of grid-enhancing technologies (GETs)

Order No. 2023 is a step in the right direction, but there is more to do to improve the interconnection process.

We (with GridStrategies) recommended these additional reforms that would increase the certainty and cost-effectiveness of generator interconnection

GridStrategies-Brattle Report, Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid (August 2024)

- **REFORM 1 | *Adopt an interconnection entry fee for proactively planned capacity***, provides interconnection customers significant interconnection cost certainty and addresses cost allocation of the upgrades identified through proactive planning processes. This reform allows projects to move forward with upfront certainty by specifying in advance the cost information in exchange for taking on some of the cost of planned transmission buildout.
- **REFORM 2 | *Implement a fast-track process to utilize existing and already-planned interconnection capacity***, implements an efficient process to quickly utilize existing and planned system capacity. In combination with Reform 1, these reforms create a fast-track process that opens up available transmission headroom for full utilization and prioritizes its use by "most ready" generator projects.
- **REFORM 3 | *Optimize the interconnection study process***, targets improvements to the interconnection study process to increase the system headroom considered to be "available" for interconnecting new resources through existing and new fast-track processes. It also identifies reforms necessary to make the study process more efficient. In combination with Reforms 1 and 2, interconnection requests should proceed through the study process more quickly.
- **REFORM 4 | *Speed up the transmission construction backlog***, addresses growing constraints to constructing network upgrades needed to bring new resources online after completing the interconnection study process.

Options for interconnecting resources 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, October 17, 2023

About the Speaker

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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.

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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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