Integrated System Planning under Uncertainty

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PRESENTED AT

LAW SEMINARS® INTERNATIONAL

Electric Power in the Southwest
Santa Fe, NM

September 23, 2025

Brattle

Our discussion today

1. **Planning Under Uncertainty**
   - The need for more proactive planning
   - Scenario-based planning for an uncertain future
   - Least-regrets planning
2. **Integrated System Planning**
   - Benefits of more integrated planning
   - Resource Adequacy + Generation Expansion + Transmission
3. **Case Study: SPP Future Energy & Resource Needs Study**

The Challenge: How to Meet Growing Needs Affordably

The challenge of meeting growing needs while keeping rates affordable 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

Better, more integrated, more proactive planning is a key tool to meet growth affordably

Transmission Example: Order 1920 Requires Improved Planning

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

1. Better deal with long-term uncertainties through proactive **scenario-based planning**
2. Use best-practice experience for 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** solutions
6. Get more out of the existing grid, focus on cost effectiveness, and include cost-control incentives*
7. Explicitly consider interregional solutions to regional needs

Key planning tools for an uncertain future

(beyond transmission):

- Scenario based
- Flexible, least-regrets solutions

*See Optimizing Grid Infrastructure and Proactive Planning to Support Load Growth and Public Policy Goals, July 2025

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:

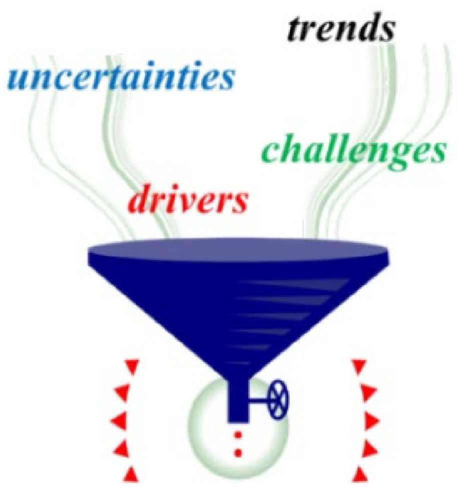
- Used by Shell with great success since the 1970s for long-term planning under large uncertainties
- **Allows planners to think, in advance, about the many ways the future may unfold and how to respond effectively and flexibly as uncertain future outcomes become reality**
- Ranks among the top-ten management 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: TransGrid and ERCOT Scenarios for LT Planning



	Current Trends	Econ Boom	High Gas	Strict Env.
Gas Prices	Base	Low	High	High
CO2 Costs	Base	Low	Base	High
Renewable Costs	Base	Low	High	High
Inflation	Base	Low	Base	Base
Gross Load	Base	Low	Base	Low

TransGrid (Australia) created and analyzed six scenarios of possible futures based on drivers and uncertainties related to: technology trends, energy policies, consumer preferences, decentralization, demand growth, market rules & regulations, and community expectations

Current trends

Ageing coal power stations are replaced with competitively priced large and small-scale renewables and storage

- Economic growth, immigration and energy efficiency are consistent with historic and projected growth rates under present trends, taking into account current projections for the recovery from COVID-19
- Electric vehicle, rooftop solar and behind-the-meter battery uptake is consistent with current central projections

Deep decarbonisation

Market forces, international and domestic politics and consumer expectations drive a huge reduction in carbon emissions across all sectors of our economy. Australia commits to limit global warming to 1.5°C, in line with the aspirations of the Paris Agreement

- Australia achieves net zero emission by 2035 and then net-negative emissions beyond
- Our electricity system is powered by 100% renewable energy from 2035
- Internal combustion engine vehicles are completely phased out by 2050, replaced primarily by electric vehicles
- Hydrogen is used for some domestic heavy-transport and industry applications and for peaking electricity generation

Prosumer power

Consumer choices and technology advancement drive a very high penetration of well-coordinated distributed energy resources into the energy system

- Extremely high uptake of rooftop solar, behind-the-meter storage and electric vehicles (many equipped with Vehicle-to-Grid capabilities)
- Artificial intelligence and automation enable the coordination of consumer devices to respond to local system and market conditions
- A net zero emissions economy is achieved by 2050

De-industrialisation death spiral

A global economic downturn causes Australia's economic growth to slump, particularly impacting the industrial sector

- Industrial electricity consumption in the NEM declines by 50% to 2025. Australia's aluminum and steel production facilities close by 2025
- Commercial electricity demand falls by 9% in the NEM before slowly growing in the 2040s

States go it alone

A breakdown of NEM regulations sees a siloed approach from the states which establish their own policies and local energy solutions. A regulatory impasse prevents new interstate transmission developments from proceeding

- New transmission links between states cannot be built, although existing links remain in use
- Each state must generate and balance its own electricity to maintain energy reliability
- Other modelling assumptions align to the **Current trends** scenario

Clean energy superpower

Australia leverages its abundant renewable energy resources and mineral ores to become a global clean energy superpower, exporting green hydrogen and metals to the world

- Australia's hydrogen sector grows to produce 19.2 million tonnes (MT) of hydrogen annually by 2050. This is broadly consistent with the high scenario from Australia's National Hydrogen Strategy
- 61% of the hydrogen produced is exported to our trading partners, 22% is used to produce green steel for export and 17% is for other domestic purposes
- Australian steel production increases significantly (from 0.3% to 5% of global steel output) and aluminum production (a five-fold growth)
- A net zero emissions economy is achieved by 2050

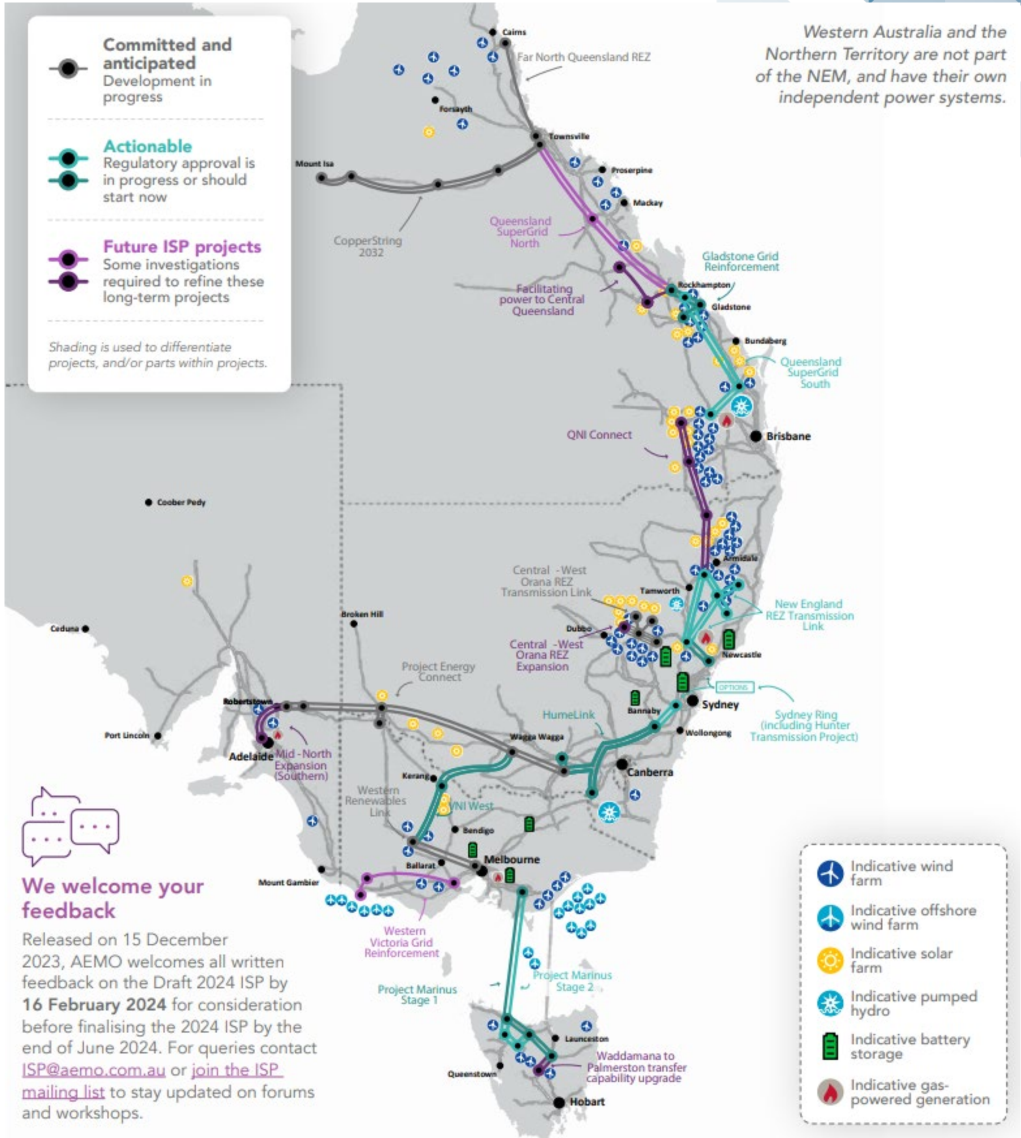
ERCOT has been undertaking similar scenario development efforts for its long-term transmission system assessments (LTSAs) since 2014

Source: Our Energy Vision | Transgrid and ERCOT Scenario Planning - Brattle

Example: Australian Integrated System Plan (ISP)

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

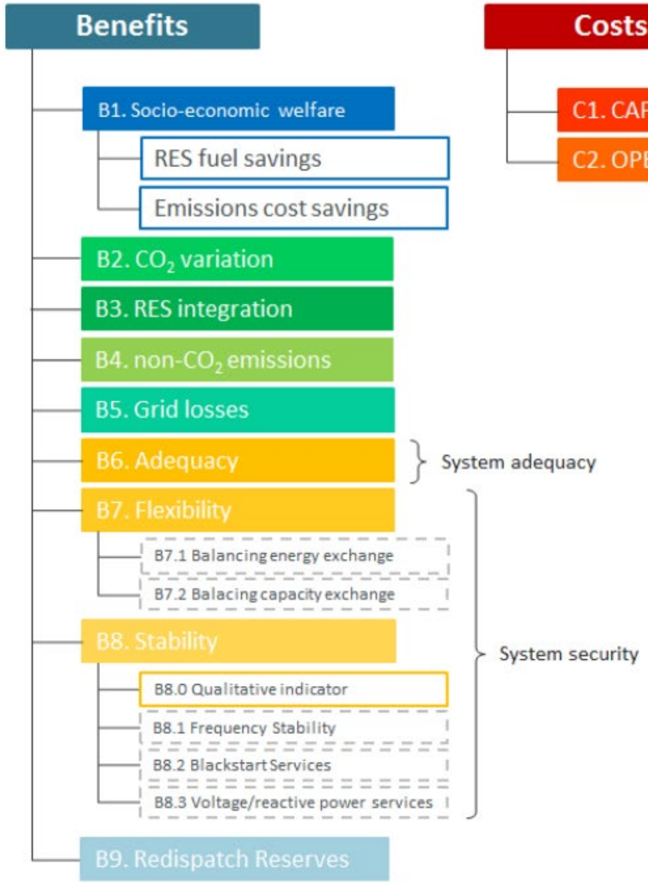
- Clearly-specified methodology (link) produces updated plans every two years with extensive stakeholder consultations (see Draft 2024 ISP)
  - Scenario-based analysis explicitly considers long-term uncertainties and risk mitigation over next 30 years (link)
  - Plans distinguish: (1) actionable projects 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

Example: European grid operators continent-wide proactive, scenario-based multi-value planning

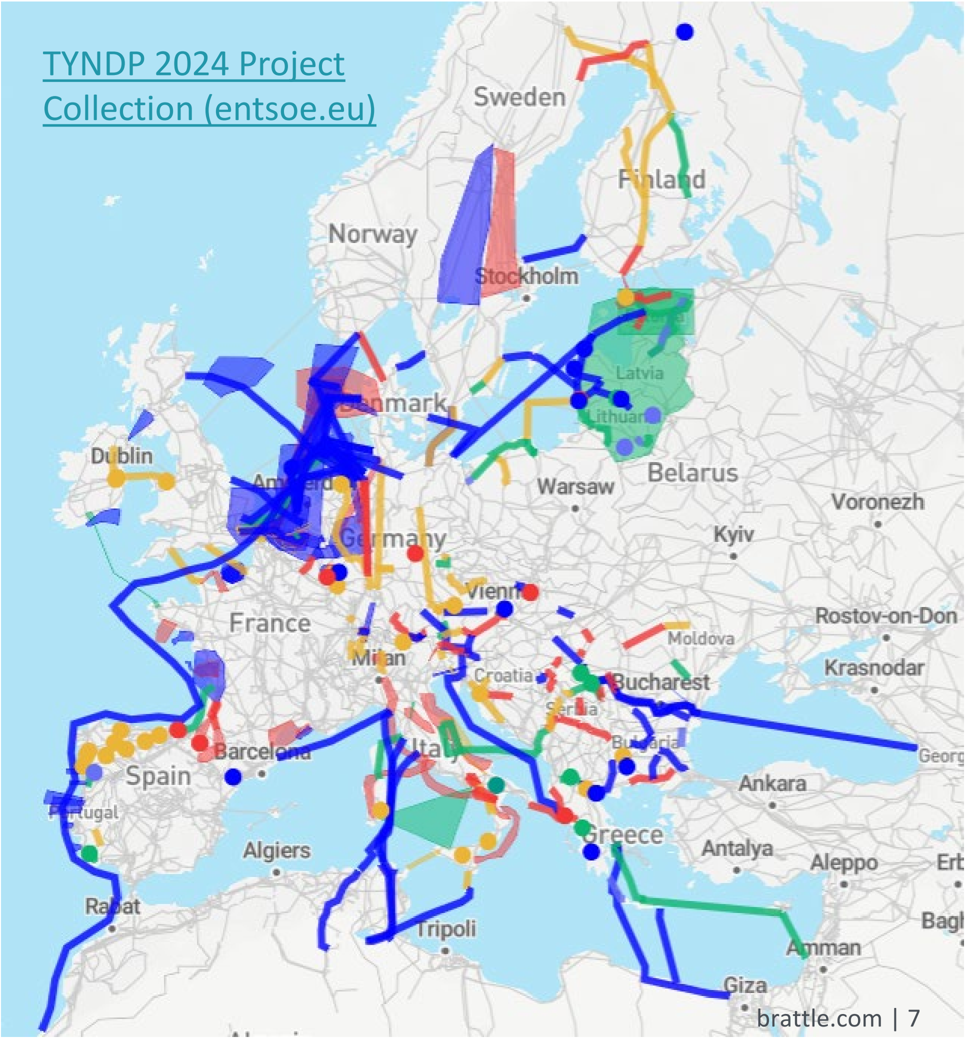
ENTSO-E: Standardized Multi-value Benefit-Cost Analysis Framework for EU-wide Transmission Planning (incl. HVDC)



Entso-E Scenario-based Planning and CBA framework

- Association of European Grid Operators
- **Scenario-based**, looking out 10-30 years
- Standardized benefit-cost analysis
- Yields 10-year investment plan

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



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.

Risk mitigation through "least-regrets" planning

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

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

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

This is what least-regrets planning should focus on!

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

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 solutions:

- Given that it can take a decade to develop new grid infrastructure, **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 value more flexible solutions that mitigate 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

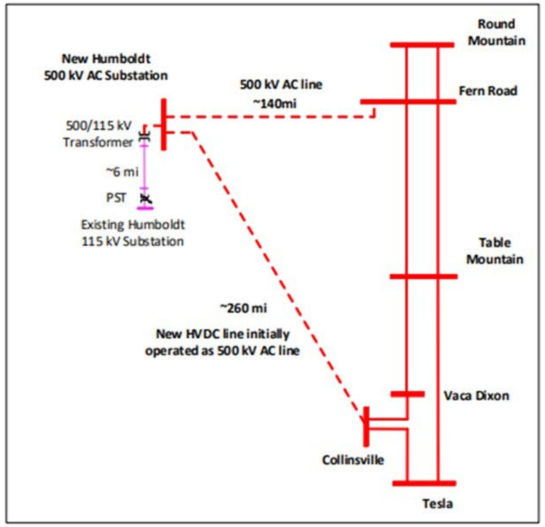
Reduce costs and mitigate risk through more flexible solutions

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

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

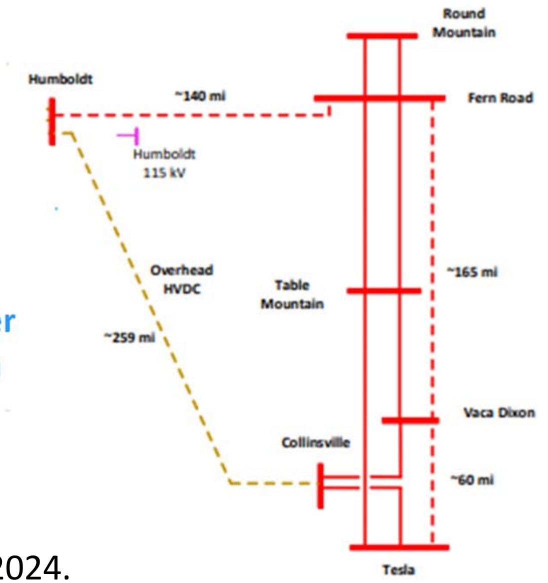
Two new 500kV lines, of which one is "HVDC-ready"

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



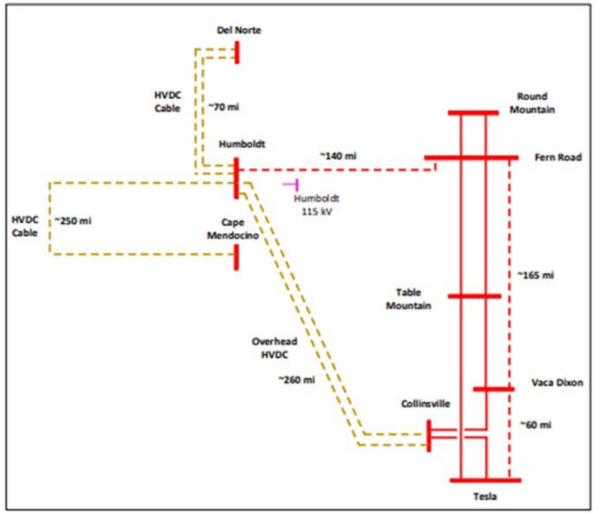
Add DC converter stations to each end of the line

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



Add a second HVDC line

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



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

Options for achieving more cost-effective, affordable outcomes

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

1. More **proactive and comprehensive planning** (as mandated for transmission 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 planning that prioritizes lower cost/impact options
   - Optimize existing resources and grid → upsize existing facilities → add new resources and 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

Example: can we double or triple US grid 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

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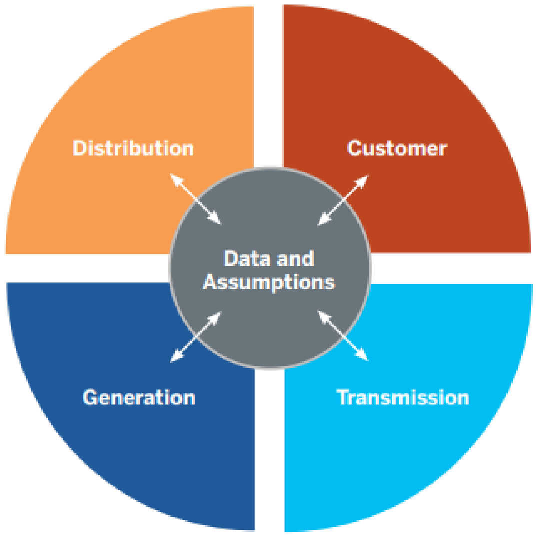
More Integrated Planning Would Offer Significant Benefits

- The Four Main Power System Planning Domains

Planning Domain	Description
Generation planning (G)	Economics-focused near- and long-term optimized capacity expansion, production cost, and resource adequacy studies to meet reliability and policy goals
Transmission planning (T)	Economic and physics-based studies to identify near- and long-term* trans-mission investment needs for capacity, reliability, stability, congestion relief, and other factors
Distribution planning (D)	Physics-based studies to identify typically near-term distribution system investment needs relative to planning criteria
Customer program and DER planning (C)	Economics-informed studies or fixed incentive budgets to support distributed energy resource solicitations, customer programs, and rate/tariff design

Integration of Inputs	Integration of Analysis	Integration of Actions	Integration with Decision-Making
Aligning inputs, modeling assumptions, scenarios, and data formats and structures across planning processes to set a common foundation across all planning processes	Determining the key data flows between both economic and physical planning analyses needed to reach a compre-hensive solution	Leveraging integrated planning analyses to determine a coordinated set of near-term proposed investments across all planning domains	Ensuring that these proposed near-term action plans fit within existing infrastructure decision-making structures or that those decision-making structures evolve to support regulatory approval and implementation of compre-hensive planning solutions

The Iterative Integrated Planning Approach

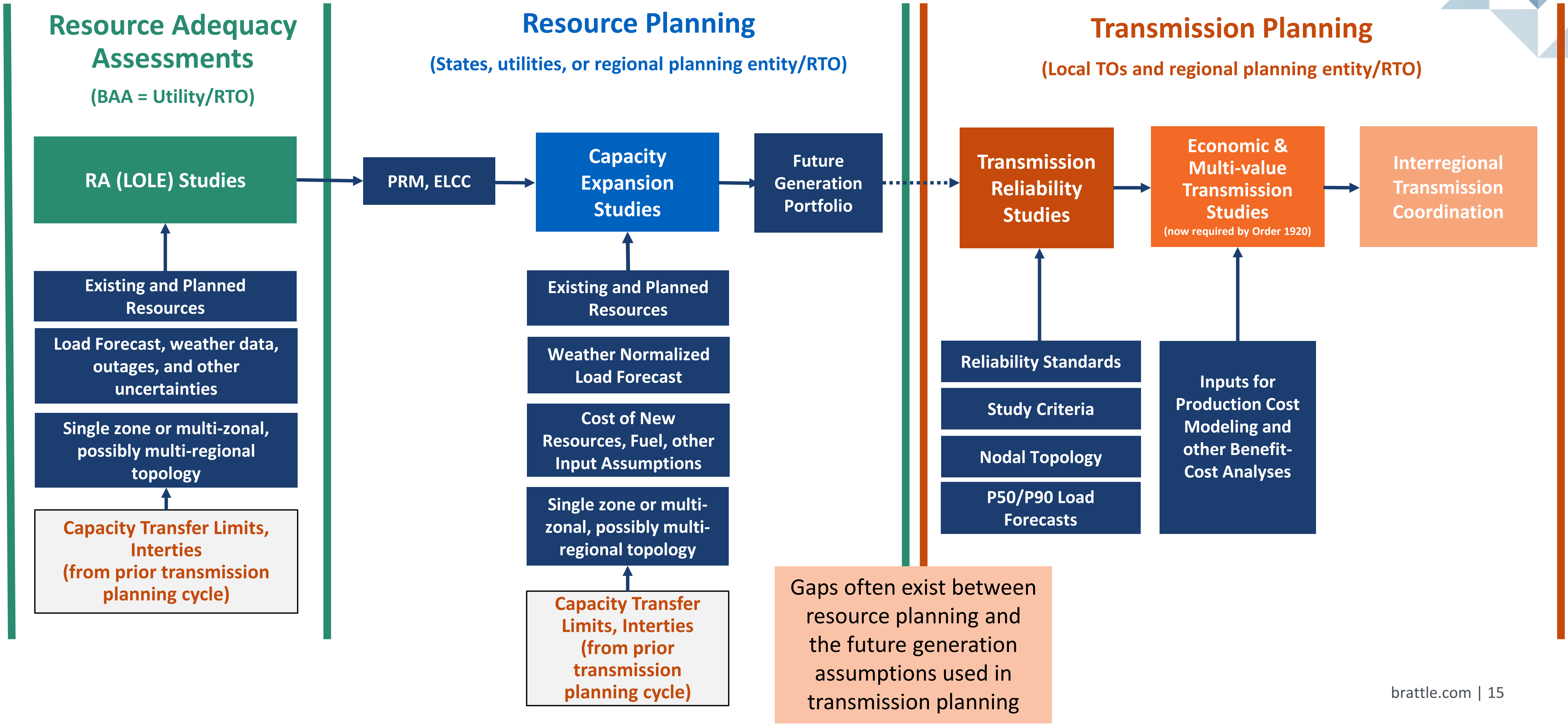


Benefits Delivered by Integrated Planning Across Multiple Dimensions

Lower costs	Integrated planning optimizes resource allocation, eliminating redundancies and reducing overall expenditures.
Increased system resilience	Planning with a comprehensive view of the energy system strengthens the system's ability to withstand disruptions, thus increasing safety, reliability, and adaptability in the face of changing demands.
Streamlined processes	Integrated planning promotes smoother utility operations by enabling coordination and consistent data sharing across planning areas.
Data integrity	Integrated planning standardizes assumptions and shared datasets for planning across generation, transmission, distribution, and customer loads and resources, thus reducing errors and improving process efficiency and electricity system reliability.
Accurate benefit accounting	Integrated planning avoids double-counting benefits while ensuring that the unique advantages of each planning area are effectively incorporated into system-wide strategies. Integration also enables a clearer assessment of reasonable reliance on markets and power purchases, ensuring that system benefits are considered not only internally but also in the context of broader market interactions and regional coordination.
Ability to balance competing objectives	Integrated planning enables trade-off analysis among priorities, such as maintaining grid reliability, ensuring grid resilience, and minimizing costs. By providing a comprehensive view of system needs and objectives, integration also facilitates more meaningful stakeholder engagement.

Source: [Integrated Planning - ESIG]

Example:
Planning for Resource Adequacy, Generation, and Transmission



Siloed Transmission Planning Processes Create Inefficiency

Local TO Reliability Planning

- Process conducted by local transmission owner (TO) to interconnect loads and meet local reliability needs or those not addressed by other planning processes

Generator Interconnection

- Process for new generation seeking to interconnect to inject energy and capacity into the grid, processed by region in conjunction with local TOs

Transmission Service Requests

- Process for service requests seeking to reserve transmission capability to support power trades

Regional Reliability Planning

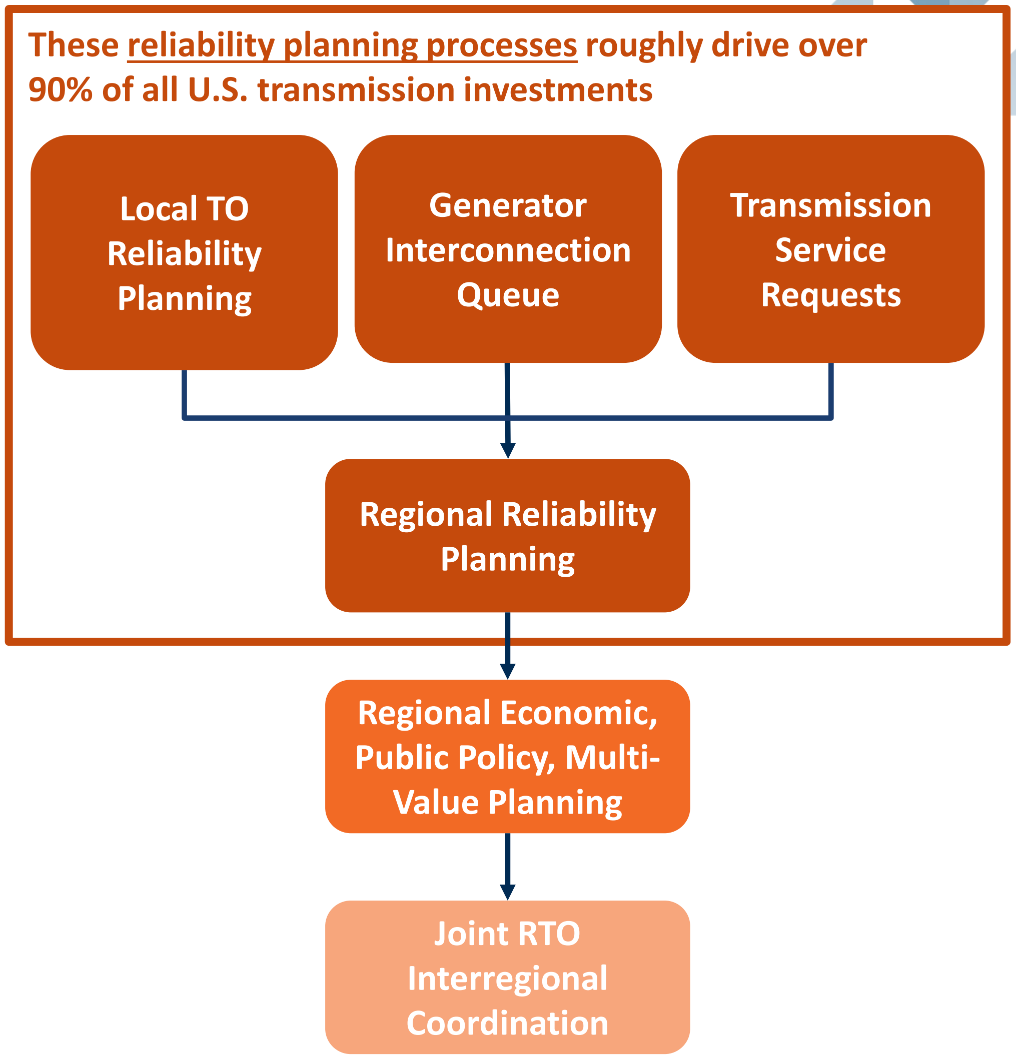
- Process to identify and address regional reliability needs

Regional Economic, Public Policy, Multi-Value Planning

- Process to address economic (market efficiency), public policy, and multi-driver needs (if applicable)

Interregional Coordination

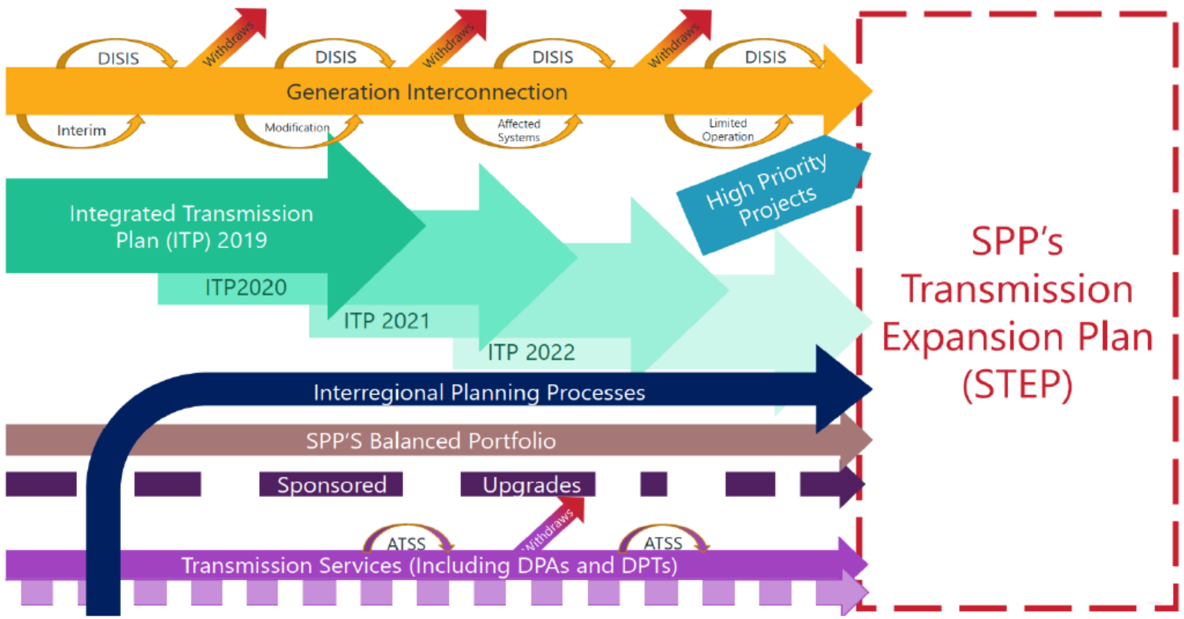
- Coordination between regions to (a) address cross-border impacts of regional planning (routinely done) or (b) identify if an interregional solution could more efficiently address regional needs/offer sufficient benefits (mostly ineffective)



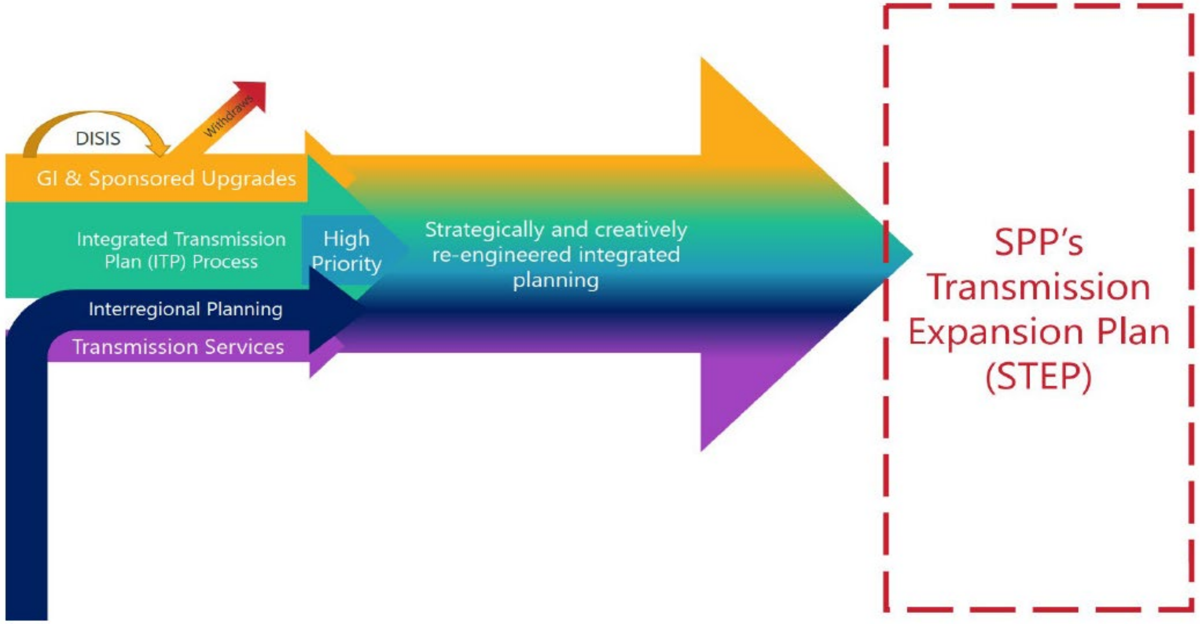
Consolidate Transmission Planning Processes

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 (CPP)

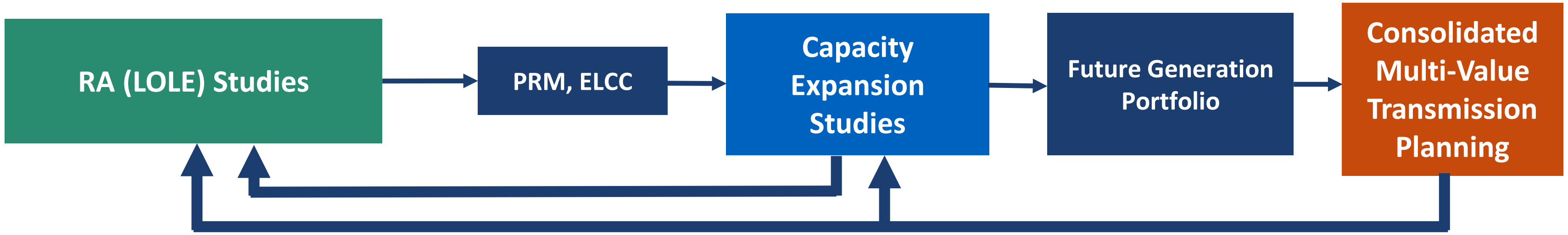


Source: Consolidated Planning Process - Southwest Power Pool

Integrated Resource Adequacy, Generation, and Transmission Planning

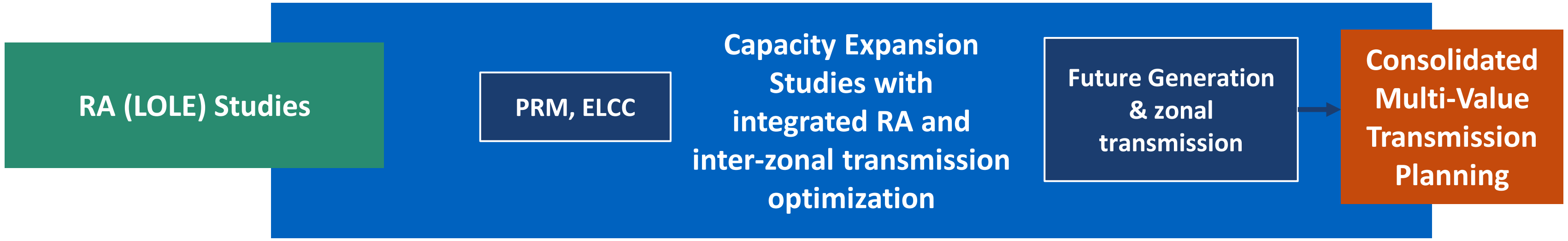
Option 1: Iterative RA, capacity expansion, and multi-value transmission planning

- RA value of transmission explicitly quantified in multi-value transmission planning (e.g., MISO LRTP)
- Iterative either within same planning cycle or (at least) across subsequent planning cycles
- Example: CPUC-CEC-CAISO coordinated (and iterative) planning process



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

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



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3. **Case Study: SPP Future Energy & Resource Needs Study**

Case Study: SPP's Future Energy & Resource Needs Study

The Brattle Group worked with SPP to:

- Examine **future costs and resource adequacy (RA) risks** in SPP under multiple scenarios of uncertain load, technology cost, and resulting resource mix
- Identify **co-optimized generation and transmission** investments that minimize system costs, capture changing market conditions, and ensure resource adequacy
- Identify future **resource adequacy** challenges based on sampled proxy periods reflecting hourly data for 15 SPP-supplied weather years and cold snaps
- Model storage and generators with **chronological commitment and dispatch** to understand their performance during challenging system conditions (heatwaves, cold snap, renewable drought, thermal outages)

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Link

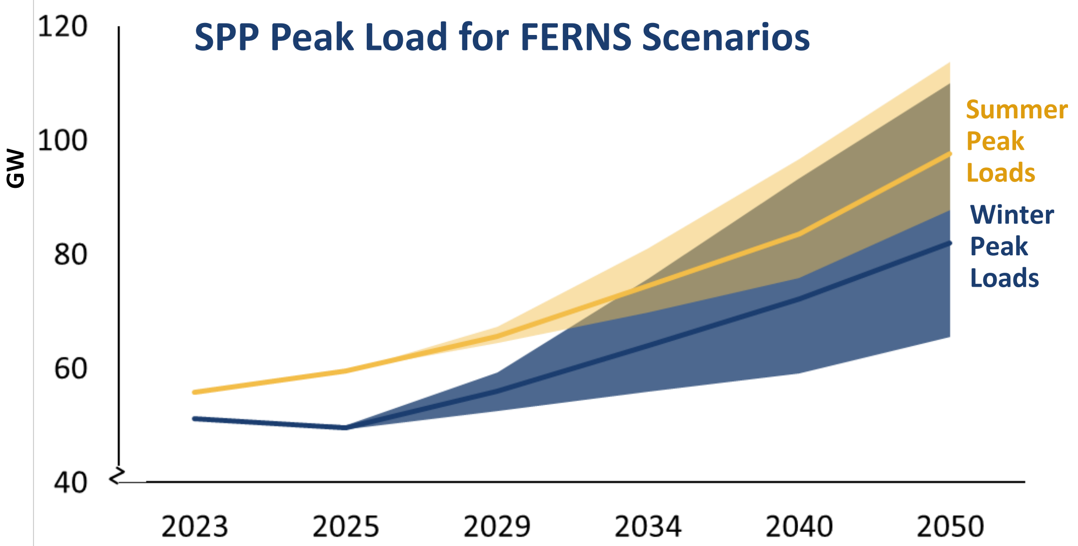
SPP

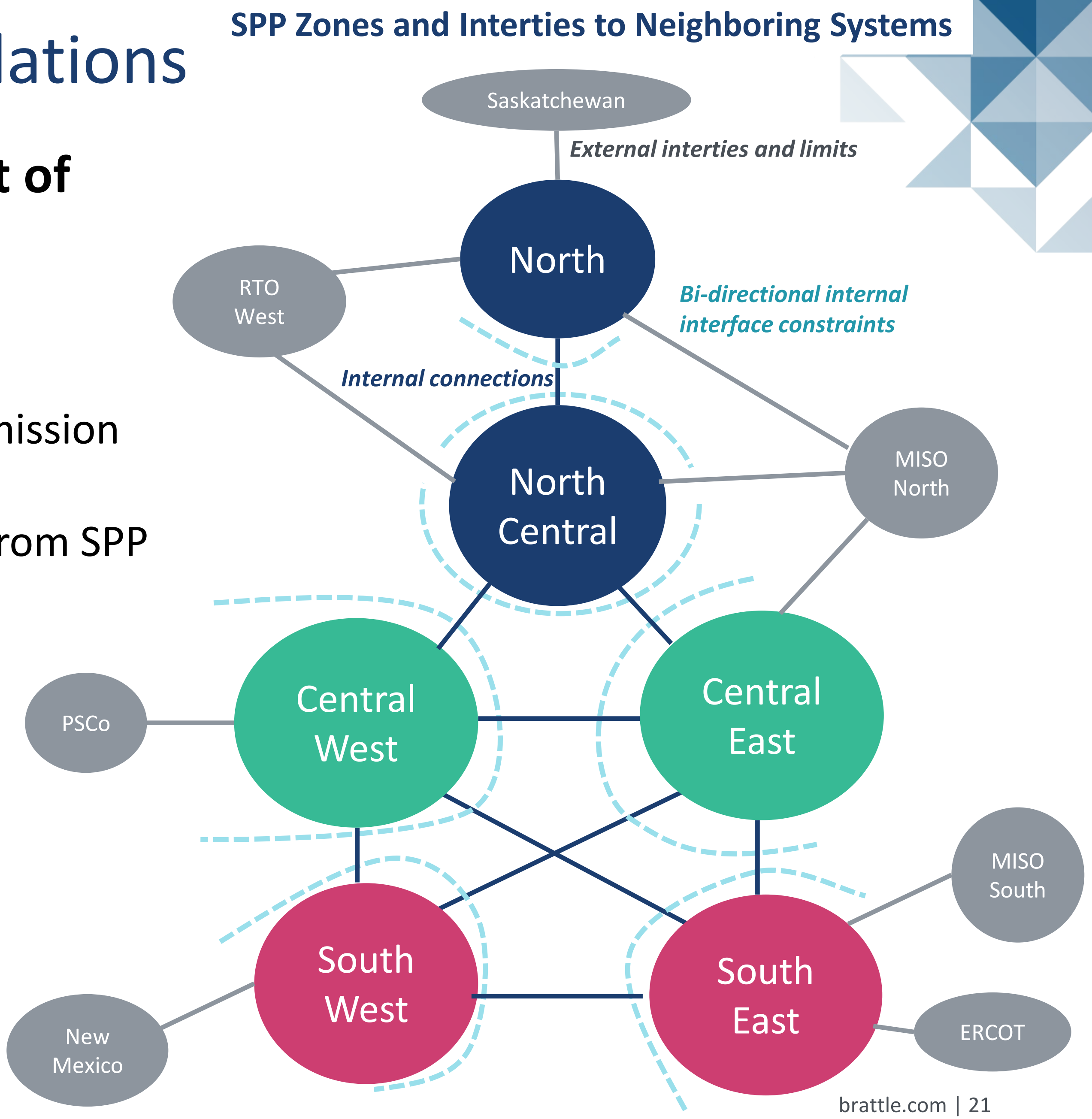
Multi-Zonal, Multi-Regional Simulations

Focused on economic and resilience benefit of regional and interregional diversity:

- Six SPP-internal zones
- Interties for eight external zones
- Contract path capabilities and simultaneous transmission limits
- Dynamic hourly transmission flows within and to/from SPP

3 load and 2 tax-credit scenarios



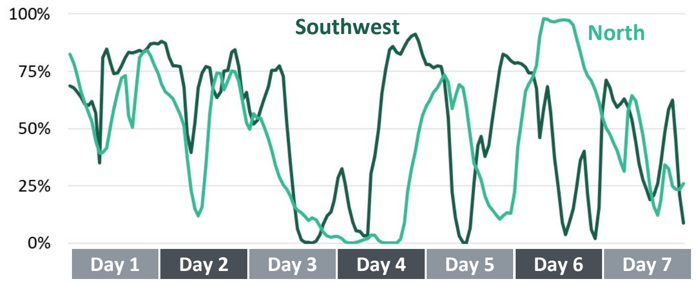


Existing and Emerging Resource Adequacy Challenges

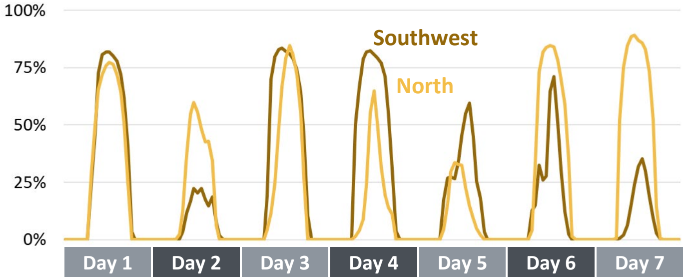
The simulations realistically captured a wide range of existing and emerging resource adequacy challenges, including:

- Cold snaps and heat waves
- Renewable droughts
- Weather-driven plant outages
- Large solar ramps and surplus

Example: Hourly Wind Profiles
(March 2020 Week in North and Southwest Regions)

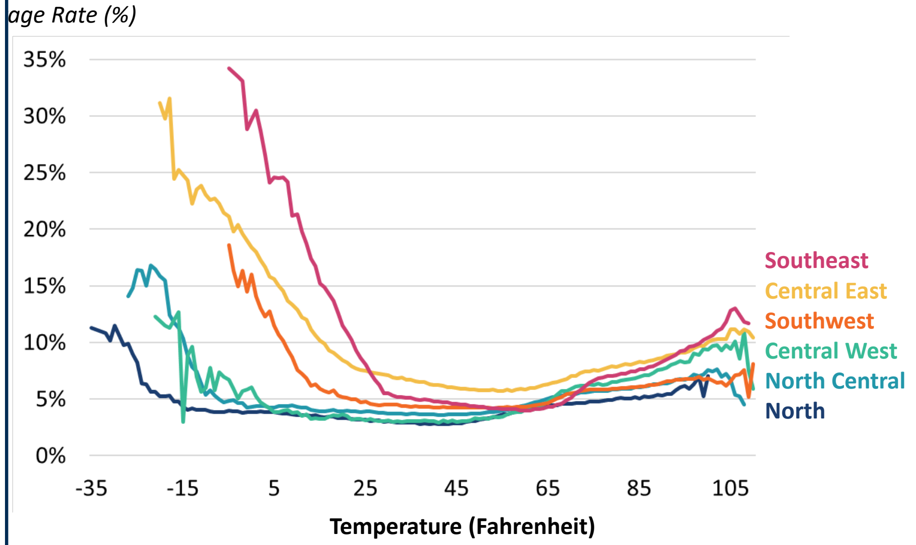


Example: Hourly Solar Profiles
(March 2020 Week in North and Southwest Regions)

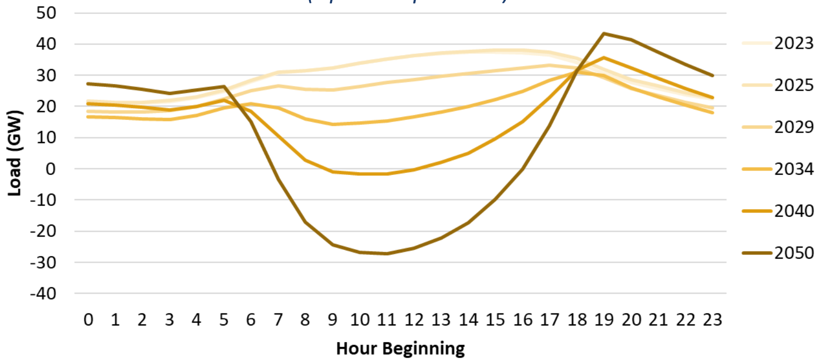


Note: Renewable profile shown for a sample week in March 2020 to highlight hourly and geographic variation in the 15-year dataset. Profile expressed as hourly generation % of nameplate capacity.

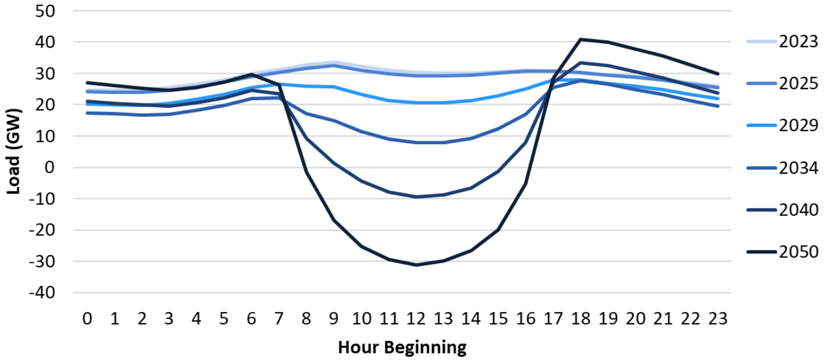
Thermal Temperature Based Outages



Average Hourly Adjusted Net Load
(April – September)



Average Hourly Adjusted Net Load
(October – March)



Note: Results show average 24-hour seasonal shapes of system gross load minus variable renewable generation (solar, wind) plus fossil outages, without any battery storage impacts. Results show the B2 scenario with medium electrification and high carbon-free resource share reaching ~90% by 2050.

Key Findings from FERNS effort

In scenarios with high load growth and high shares of renewable generation, SPP is projected to **maintain resource adequacy in a cost-effective and affordable manner** if fossil-fuel generation capacity is retained (or replaced) for reliability purposes and sufficient new resources, including storage, are added to the SPP system.

A projected **$88–$263 billion of generation** investments will be needed to support SPP's load growth through 2050. This is possible **without significant rate increases (in inflation-adjusted terms)** due to load growth and fuel-cost savings, especially if federal tax credits (or similar renewable generation support) remain available.

Between **70% and 90% of SPP's annual energy is projected to be generated from renewable resources by 2050**, though conventional generation is expected to continue to serve a large share of SPP's resource adequacy needs, representing 40–60% of the region's accredited capacity. This is a function of technology costs, natural gas prices, and the availability of tax credits (or similar policies).

Solar generation is projected to outcompete wind generation. By 2050, 20–48 GW of new wind generation is expected to be added, which compares to 42–130 GW of new solar generation. As solar generation expands, 22–59 GW of battery storage is projected to be cost-effective (and often co-located) to maintain resource adequacy.

Key Findings from FERNS Simulations

4–21 GW of new regional transmission capacity (between SPP zones) is projected to be cost-effective by 2050, necessary to support the delivery of generation to load centers.

Resource adequacy challenges evolve over time to be more frequent during: (a) winter months (particularly in high electrification futures) and (b) the early evening hours (after sunset). This implies that **winter planning reserve margins will need to be significantly higher than summer reserve margins,** due to low solar capacity values and high temperature-correlated fossil outages in the winter.

SPP has **sufficient available land to accommodate** the projected 60–180 GW of wind and solar generation capacity additions through 2050 in all scenarios evaluated.

The effective load carrying capability **(ELCC) value of solar and short-duration storage resources is projected to decline over time**, while the ELCC of wind resources increases slightly. Even the ELCC of 8-hour storage declines in the high renewable generation scenarios, indicating a need for long-duration storage. Interties with neighboring regions offer valuable resource adequacy and extreme-weather resilience benefits to the SPP footprint.

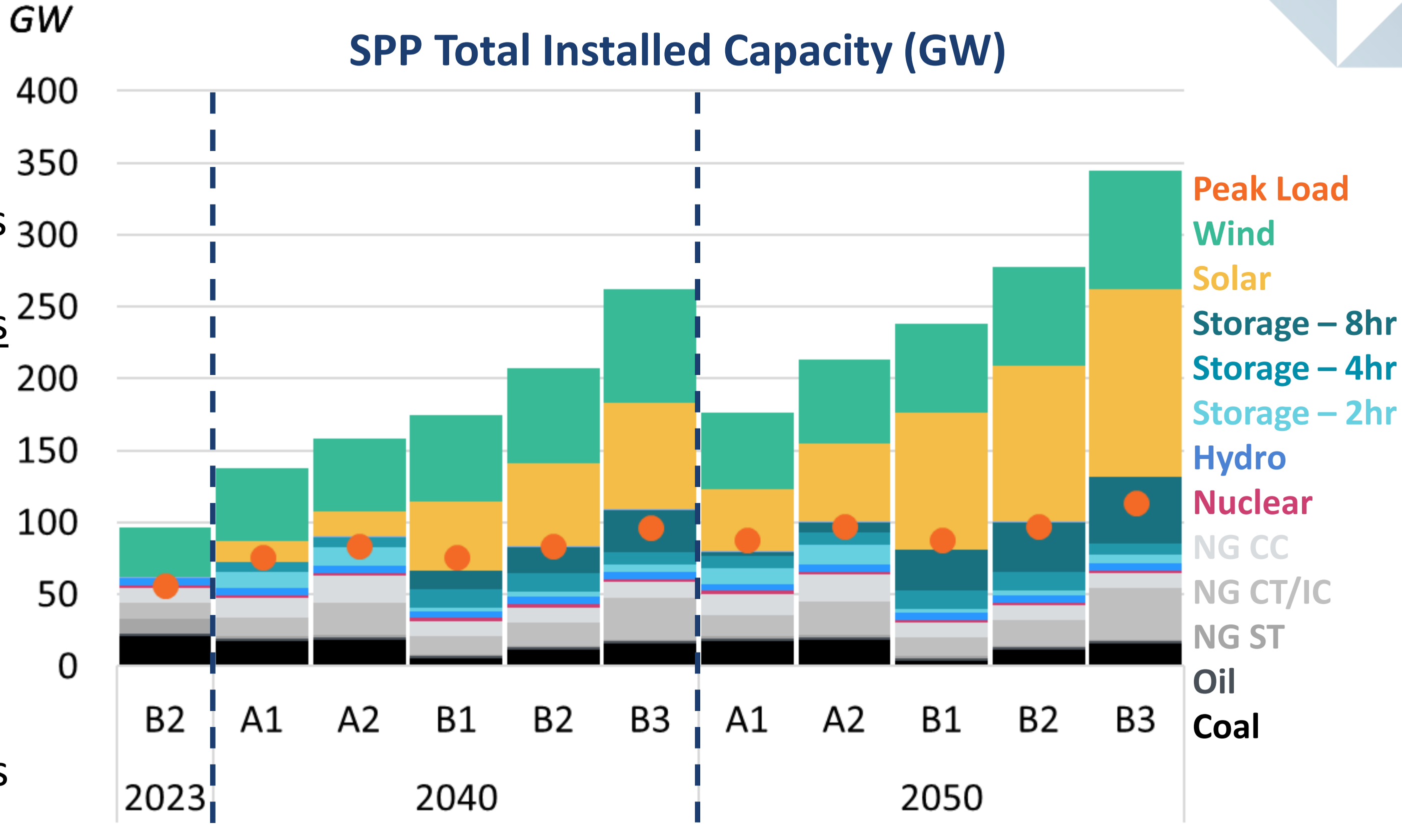
SPP is projected to become a **more significant net exporter by 2050**, particularly in the high renewable generation scenarios, due to the high-quality of renewable generation in the region.

		Carbon Free Resource Shares	
		Moderate	High
Electrification	Low	A1	B1
	Moderate	A2	B2
	High		B3

Capacity Buildout Across Scenarios

The extent to which SPP will electrify and decarbonize will lead to different optimal resource solutions as shown through scenario analysis:

- **Through the 2020s:** In the near term, all scenarios have comparable capacity buildout driven by <u>already scheduled retirements and planned builds</u> currently in the interconnection queue
- **In the 2030s:** High decarbonization scenarios replace fossil capacity with low-cost <u>renewables and storage</u> resources, with more resources needed for higher electrification scenarios
- **In the 2040s:** Longer duration storage becomes a key resource adequacy asset for the high decarbonization scenarios paired with renewables (primarily solar). Moderate decarbonization scenarios rely on more fossil, shorter duration storage assets, and much less solar by 2050



Note: Only select later years, 2040 and 2050, are highlighted in this chart. For full capacity buildout by year see detailed tables later in the appendix.

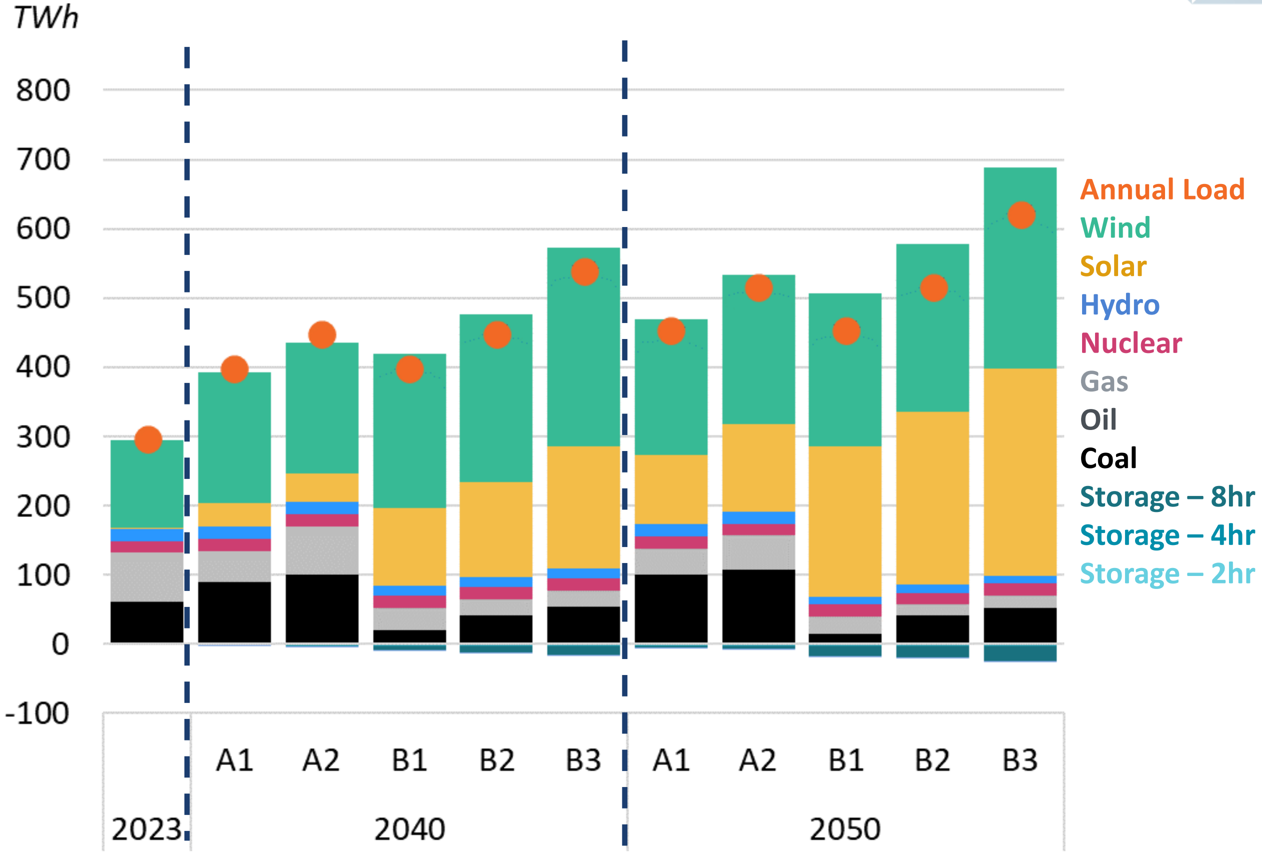
Generation Output Across Scenarios

Carbon Free Resource Shares		
Electrification	Moderate	High
Low	A1	B1
Moderate	A2	B2
High		B3

Electrification and decarbonization scenarios lead to different optimal use of the generation fleet:

- **Through the 2020s:** In the near term, all scenarios have comparable buildout with less generation in lower electrification scenarios
- **In the 2030s:** By the 2030's, high decarbonization scenarios deploy mostly new solar resources in SPP, while moderate decarbonization buildout continues to rely more heavily on fossil resources to meet electrification load
- **In the 2040s:** High decarbonization scenarios continue to deploy renewables for local demand and for cost-effective exports to neighboring regions. High decarb scenarios result in ~90% carbon-free while moderate decarbonization results in ~70% carbon-free generation by 2050

SPP Annual Energy Generated (TWh)



Note: Total SPP generation exceeds annual load in years when SPP is a slight net exporter to neighboring regions. This occurs in later years when SPP is highly renewable saturated.

Interzonal SPP Transmission Expansion by Scenario

	Carbon Free Resource Shares	
Electrification	Moderate	High
Low	A1	B1
Moderate	A2	B2
High		B3

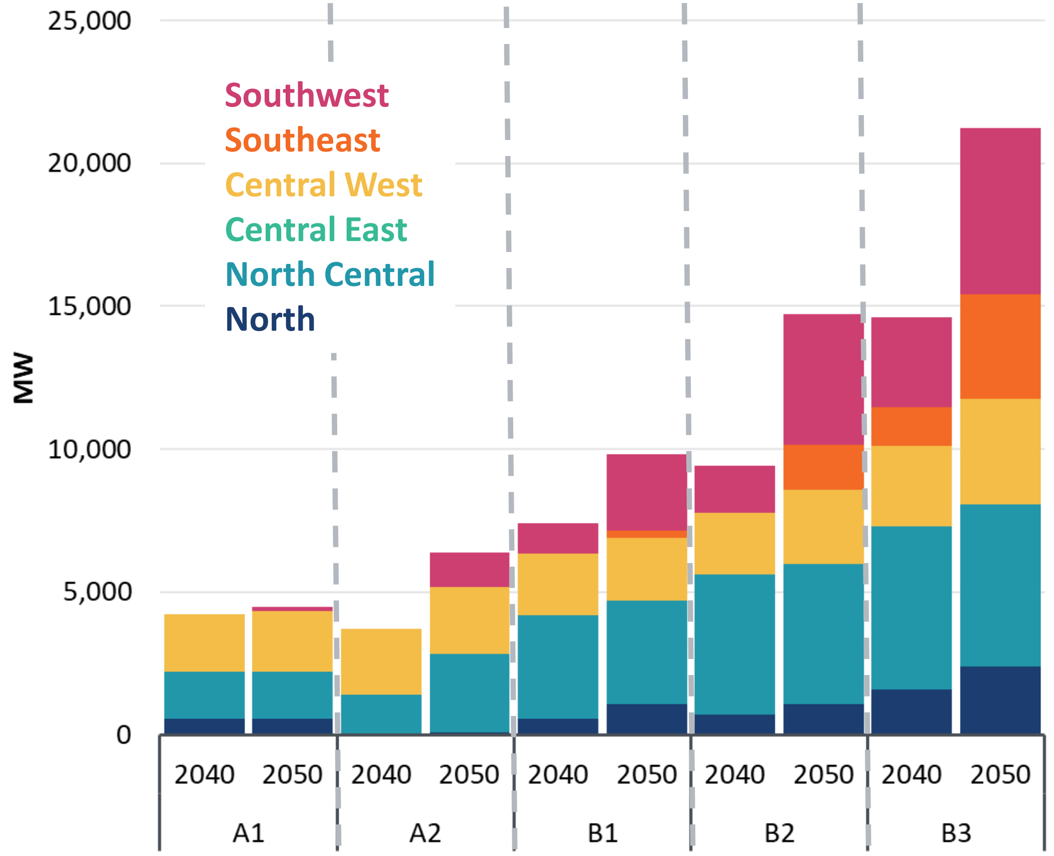
The need for additional SPP interzonal transmission (relative to assumed import/export limits of LOLE zones) varies significantly with electrification and decarbonization trajectories:

- Moderate carbon-free scenarios (A1, A2) result in the lowest demand for additional interzonal transmission because load is met by local dispatchable fossil generators
- In high decarbonization scenarios (B1, B2, B2), it is more cost effective to locate (the lower-cost) renewables in high resource-quality regions (Southern and Central zones) and invest in transmission infrastructure when renewables are not zonally located with load.
- Although carbon-free share drives differences in transmission investments, higher electrification leads to increased transmission builds in order to accommodate increased SPP wide demand and additional generation needed to serve load
- The optimal level of transmission expansion is a function of both transmission costs and generation costs

A portion of these expansion levels will be addressed by SPP's 2024 ITP proposed transmission investments, which total $7.7 billion. FERNS modeling was completed before ITP 2024 release.

SPP Cumulative Economic Interzonal Incremental Transmission

(MW of added zonal import/export capability by 2050)



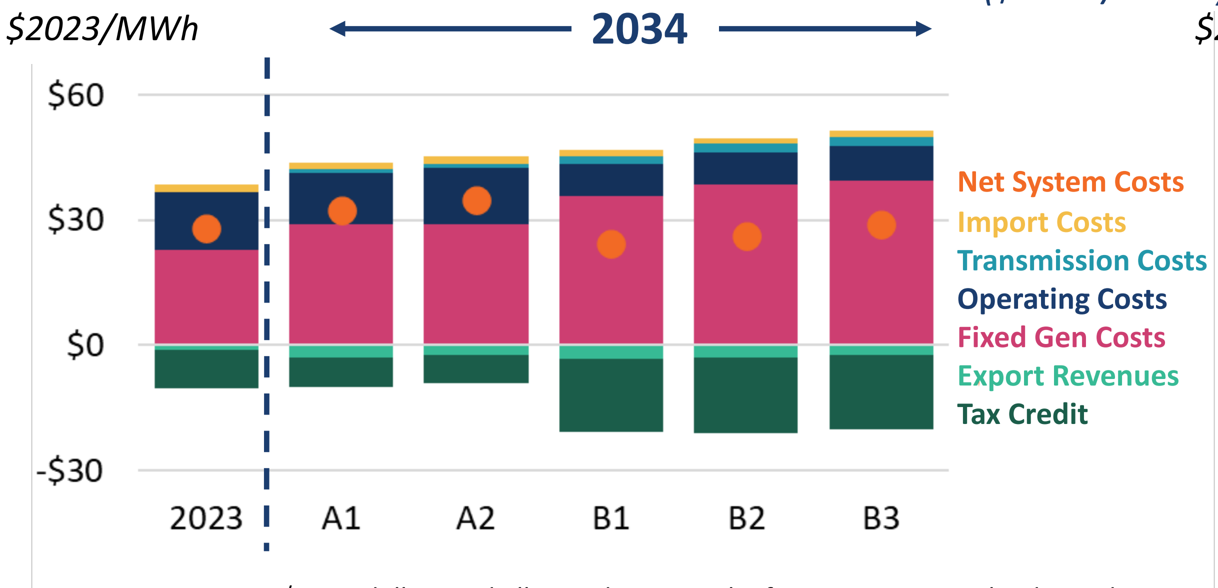
Average ($/MWh) G+T Costs Across Scenarios

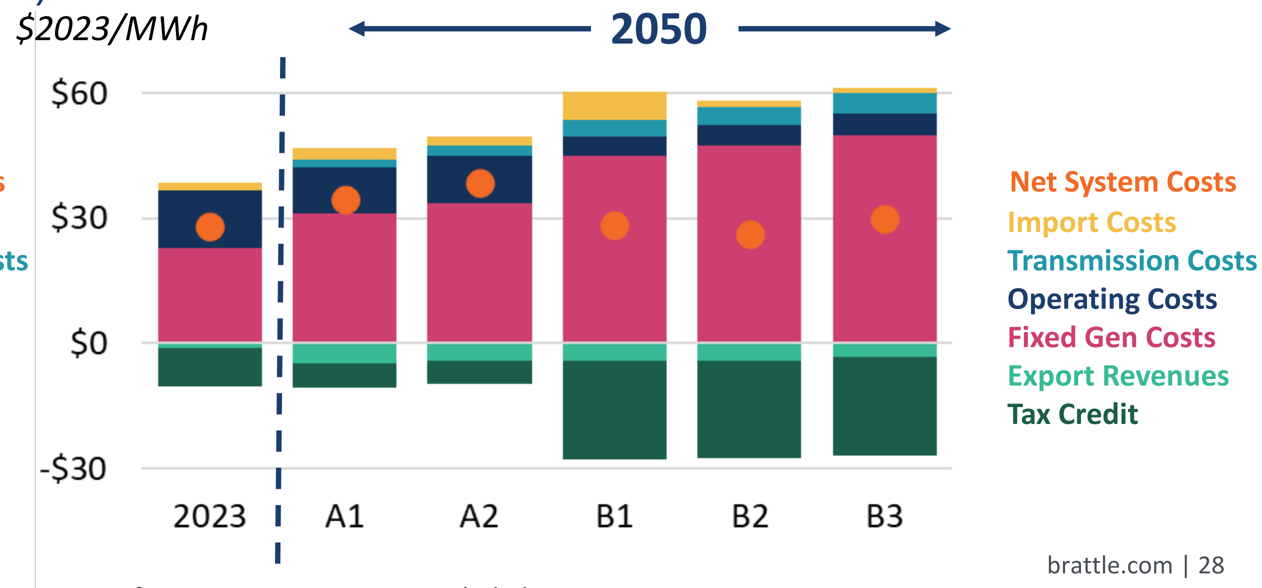
Electrification	Moderate	High
	Carbon Free Resource Shares	
Low	A1	B1
Moderate	A2	B2
High		B3

Per-unit system costs (total annualized cost divided by total annual load, in inflation-adjusted 2023 dollars) show modest increases in Scenarios A1 and A2; with no increases in Scenarios B1 – B3:

- Moderate carbon-free resource scenarios (A1, A2) have $10/MWh cost increases (in 2023 dollars) driven by additional fossil generation costs, while B scenarios have no cost increases due to value of continued tax credits
- On a per-MWh basis, differences in electrification scenarios do not drive significant differences in system costs
- This suggests SPP could achieve high levels of decarbonization and electrification with minimal rate impacts

SPP Unitized System Costs
($2023/MWh)





Note: costs are in $2023 dollars and allocated over MWh of SPP system gross load. Fixed costs recovery of existing generation not included.

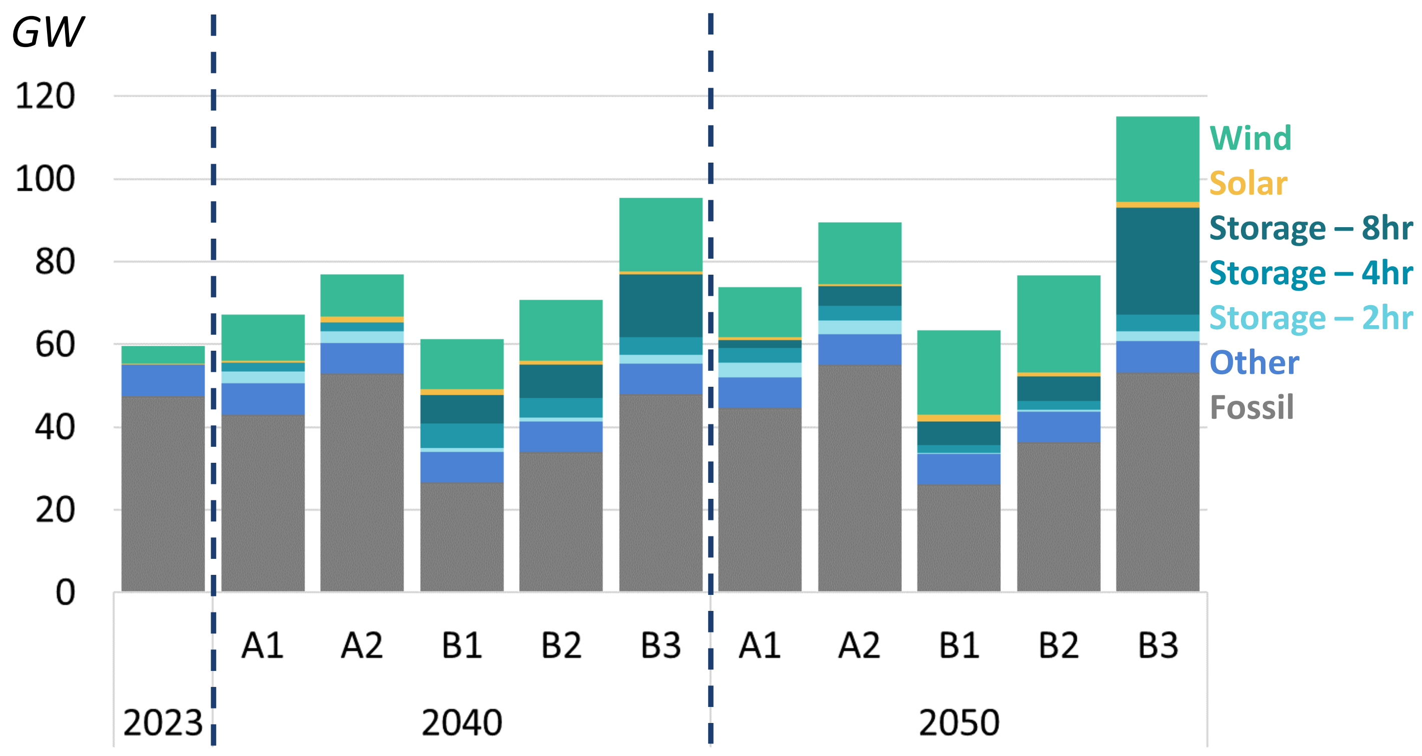
Available Capacity During 100 Most Challenging Hours

Electrification \ Carbon Free Resource Shares	Moderate	High
Low	A1	B1
Moderate	A2	B2
High		B3

SPP will continue to rely on fossil resources during challenging system hours:

- **Today:** SPP primarily serves load during risk hours (high summer load and winter risk days) with thermal resources, supplemented by low quantities of wind and nuclear generation
- **2040:** Wind resources increase their contributions in peak hours across all scenarios, with high-renewable scenarios also relying on battery storage
- **By 2050:** Fossil resources still contribute to 40% to 60% of rated capacity in RA risk hours in scenarios with 70-90% clean energy generation

SPP Available Capacity During 100 Highest RA-Risk Hours (GW)



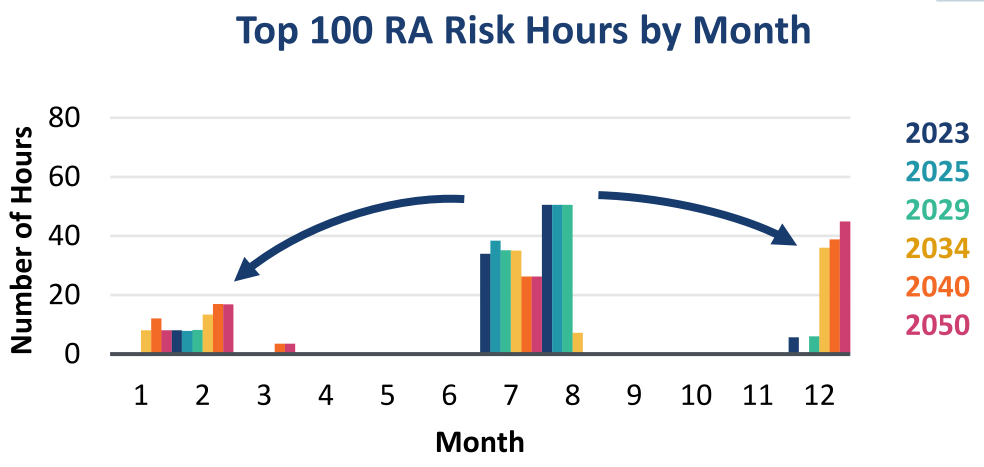
Note: Only select later years, 2040 and 2050, are highlighted in this chart.

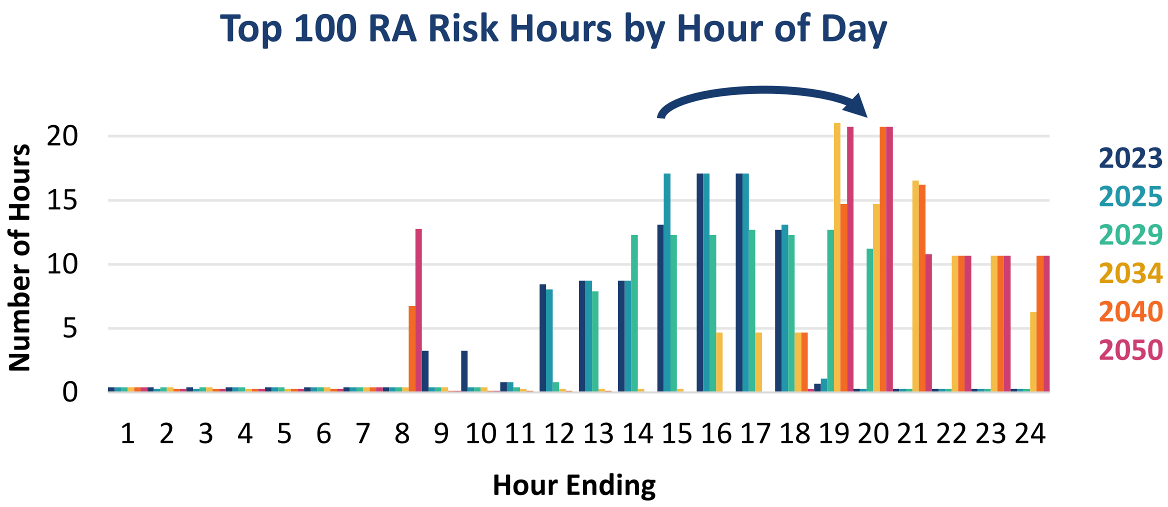
SPP Evolving Resource Adequacy Needs and Challenges

Simulations show SPP resource adequacy challenges evolve over time as the system electrifies and decarbonizes, reflecting changing net loads:

- **Through the 2020s:** Resource adequacy risk continues to be primarily concentrated during early summer afternoons and during (infrequent) severe winter cold-snaps
- **In the 2030s:** Net load conditions (high solar generation) shift resource adequacy risk to later evening hours and increased frequency of RA challenges during winter months
- **In the 2040s:** Tight resource adequacy hours become significantly more frequent in winter months, during mornings and late evenings (even outside of severe winter storm periods)

Charts show the top 100 hours with highest resource adequacy risk in each year (defined as hours with the lowest "supply cushion") and reveal when tight conditions could occur.

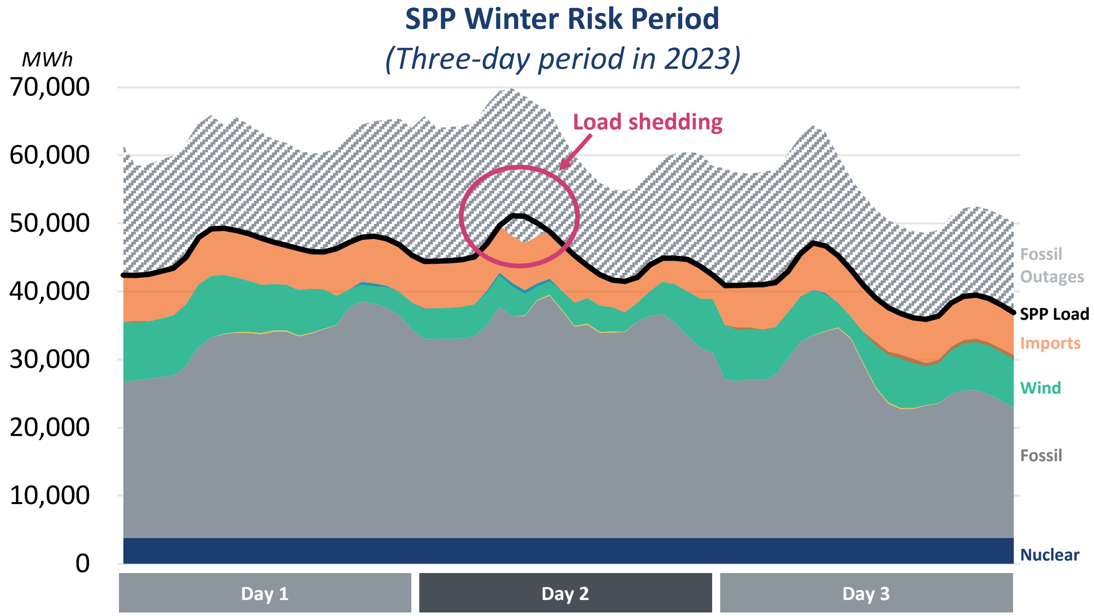


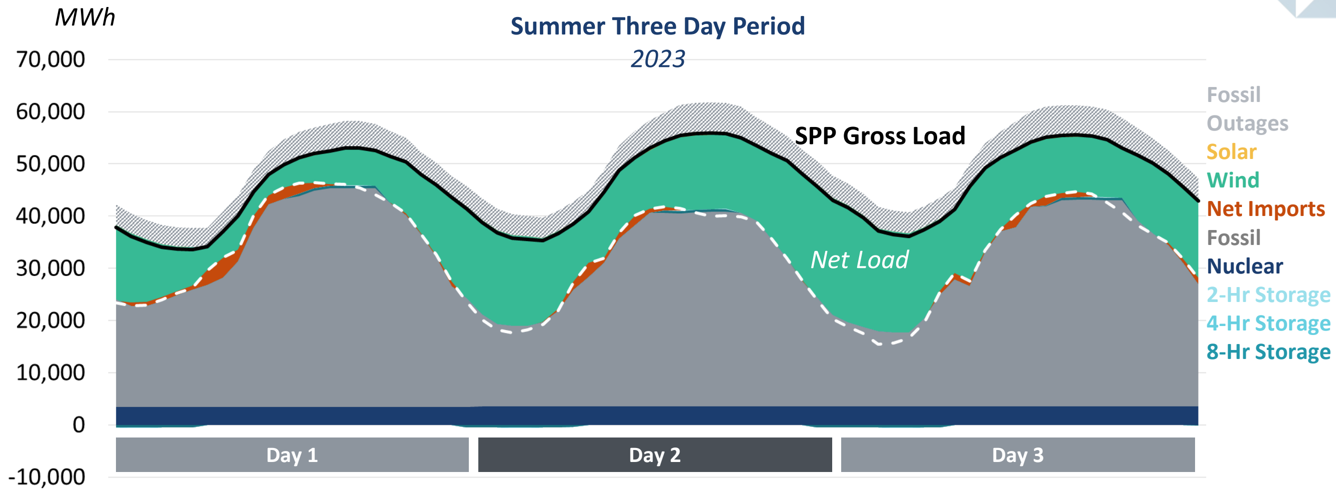


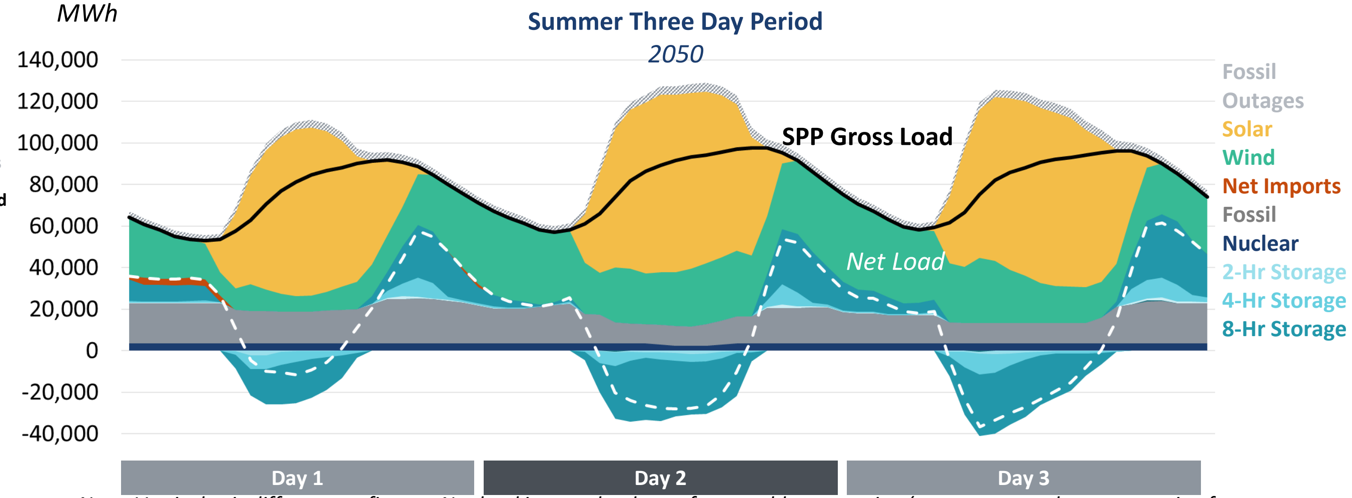
SPP Operations: Winter Cold Snap and Summer Days: 2023 vs. 2050

As SPP's resource mix changes over the next 25 years, renewables and storage:

- Solar generation yield a "duck curve" net load
- Fossil plants continues operations as a base load
- The highest RA risks occur during cold-snap period (representing Uri-like severe winter storms, assumed to occur once every 5-10 years)

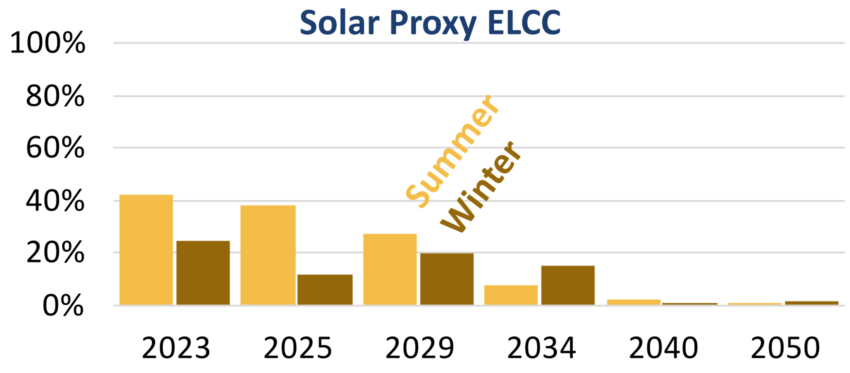


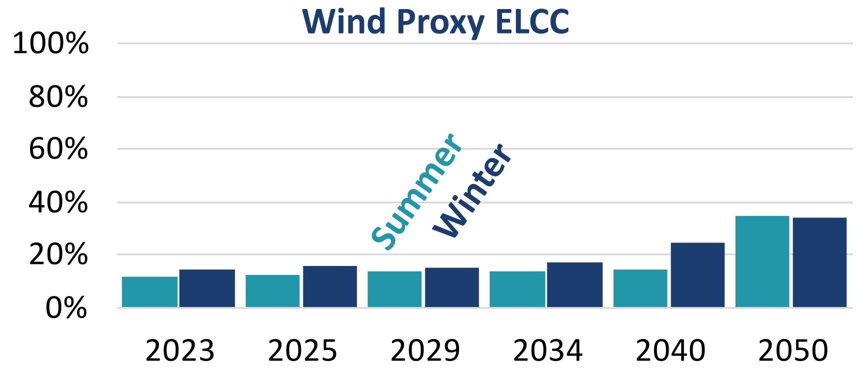


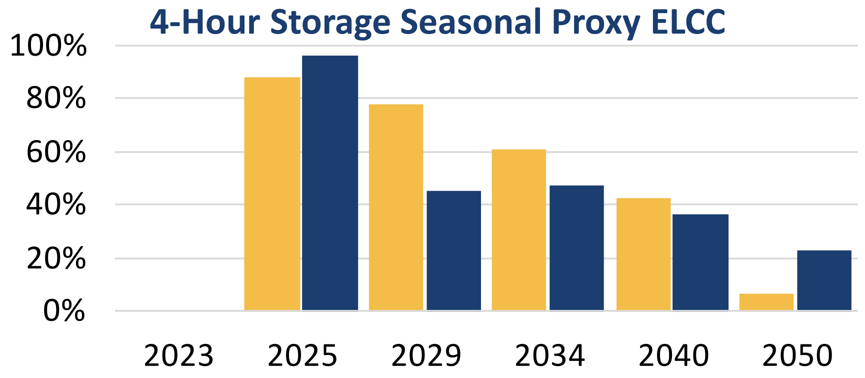


Note: Vertical axis differ across figures. Net load is gross load net of renewable generation (not storage and not accounting for fossil outages because they are shown individually in the chart.

Seasonal "Proxy ELCC" Values of Wind, Solar, and Storage







ELCC values endogenously determined within planning model (based on average of resource performance during the top 100 most resource-adequacy challenged hours:

- ELCC value of solar generation, high through early 2030s, declines quickly as "net peak" is shifted into the early evening
- ELCC value of wind generation, plateaued through late 2030s, increases as RA-challenged hours shift into winter and evenings, when wind generation is higher
- ELCC value of 4-hour battery storage, high initially, declines in the 2030s as longer duration storage is needed to supply loads evening and night-time loads
- Even 8hr storage shows declining ELCC values in high solar futures, suggesting that longer duration storage may become cost-effective

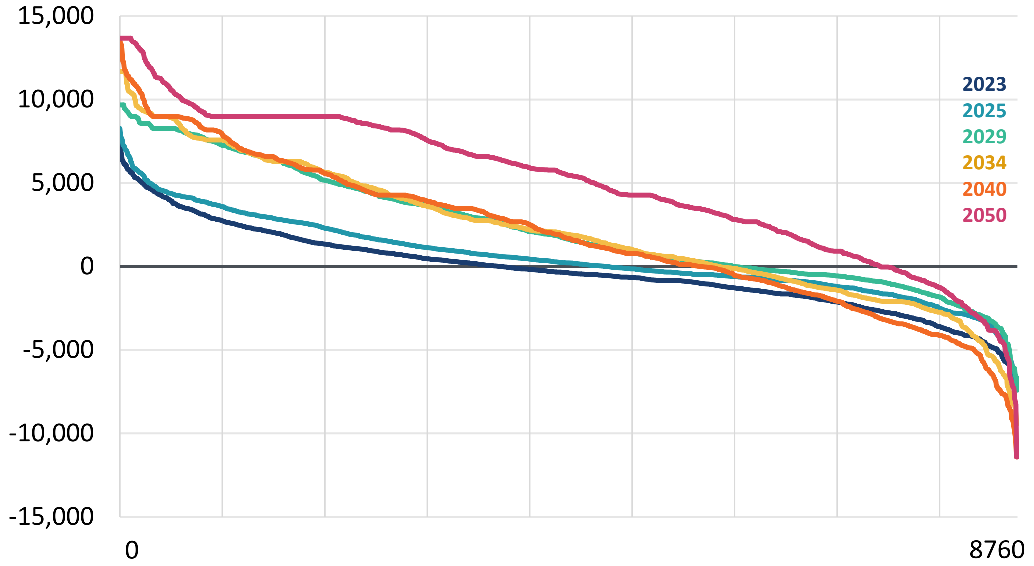
Trade with Neighboring Regions (Scenario B2)

SPP trades with all neighboring regions through interties with MISO, ERCOT. and the West

- **Through the 2020s:** SPP is a slight net exporter, exporting from other regions in just over half the hours throughout the year
- **In the 2030s:** Through the 2030's as SPP continues to deploy solar and wind resources, SPP begins to export more generation to neighboring regions
- **By 2050**, SPP exports in most hours of the year as neighboring regions import low-cost renewables

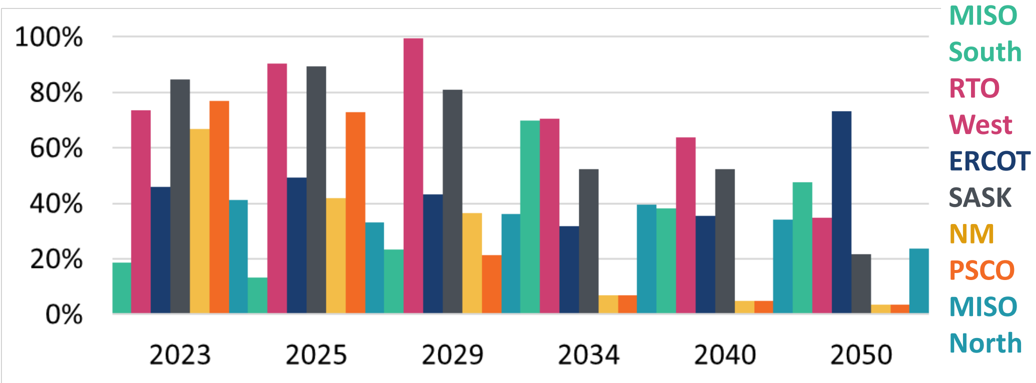
Although interties with neighboring regions are not assumed to contribute to SPP resource adequacy requirements, SPP can often import energy to serve load during scarcity periods. We quantified the implied proxy "ELCC" value based on the (non-firm) energy imports to SPP over external interfaces during the 100 highest resource adequacy risk

SPP Net Imports and Exports across all interties (MW)
(Positive = net flow out of SPP; Negative = net flow into SPP)



Note: Net imports shown across interfaces between SPP and all neighboring regions

Implied "Proxy ELCCs" of Non-firm Energy Imports over Interties with Neighboring Regions (Scenario B2)



FERNS – Planning Implications and Next Steps

SPP's FERNS was an exploratory study, not (yet) part of an actionable planning process:

- Proof of concept showing that resource adequacy needs and interzonal transmission expansions can be co-optimized with simulations of generation expansion and retirements
- SPP has already used FERNS result (including its separate land availability analysis) to inform the long-term generation assumptions used in its transmission planning efforts
- FERNS generation and transmission expansion results are focused on only one scenario at a time. These would be the starting point for developing robust/flexible solutions that perform well across the full range of scenarios

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, resource planning, and transmission. He has supported planning, market design, and regulatory efforts by independent system operators, integrated utilities, public power companies, transmission companies, generation developers, industry groups, and regulatory agencies across North America. He has worked with clients in SPP, MISO, PJM, New York, New England, ERCOT, CAISO, WECC, and Canada.

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 Electrical Engineering and Energy Economics from the University of Technology in Vienna, Austria.

The main drivers of transmission needs and cost implications

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

Best practices for proactive, comprehensive, long-term grid planning

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

1. Comprehensively consider <u>all needs over longer time frames</u> (e.g., consolidate grid 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

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

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

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

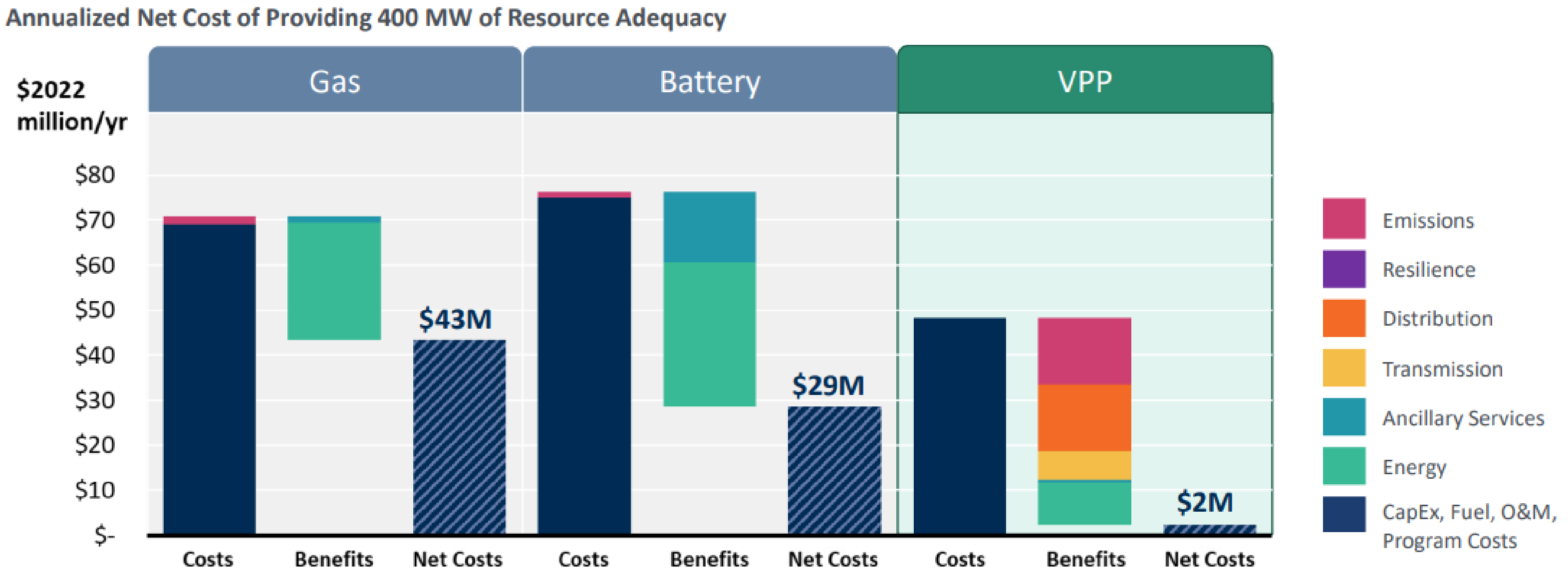
- **Broad-based** performance-based ratemaking (PBR),
  - UK incentives for transmission providers (for both investments and operations) under "RIIO"
  - Australian incentive schemes for networks: efficiency benefits sharing scheme (EBSS), capital expenditure sharing scheme (CESS), and service target 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

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)

Significant barriers to planning new 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.

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)

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

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Kasparas Spokas
J. Michael Hagerty
John Tsoukalis

Grid Strategies:
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Michael Goggin
Jay Caspary
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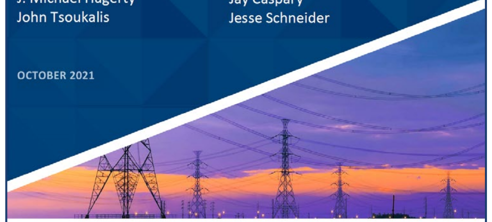
OCTOBER 2021



Brattle

GRID STRATEGIES LLC

Summarizes proven approaches to quantifying various benefits

Brattle Group Publications on Transmission

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