Are Firm Capacity Requirements Outpacing Replacements?

PRESENTED BY
Johannes Pfeifenberger

PREPARED FOR
Future Power Markets Forum

January 25, 2024

Brattle

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NERC's December 2023 Long-Term Reliability Assessment

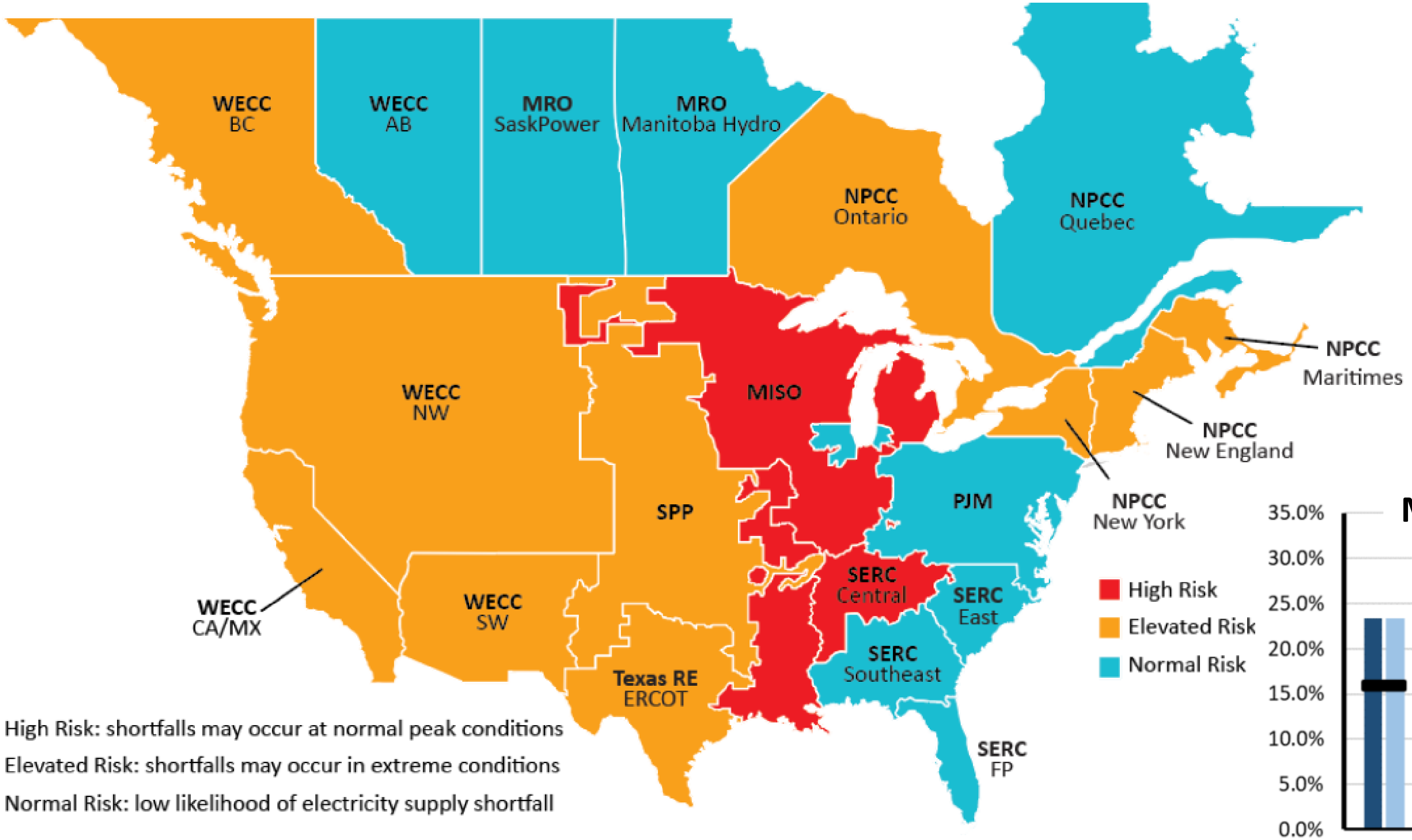
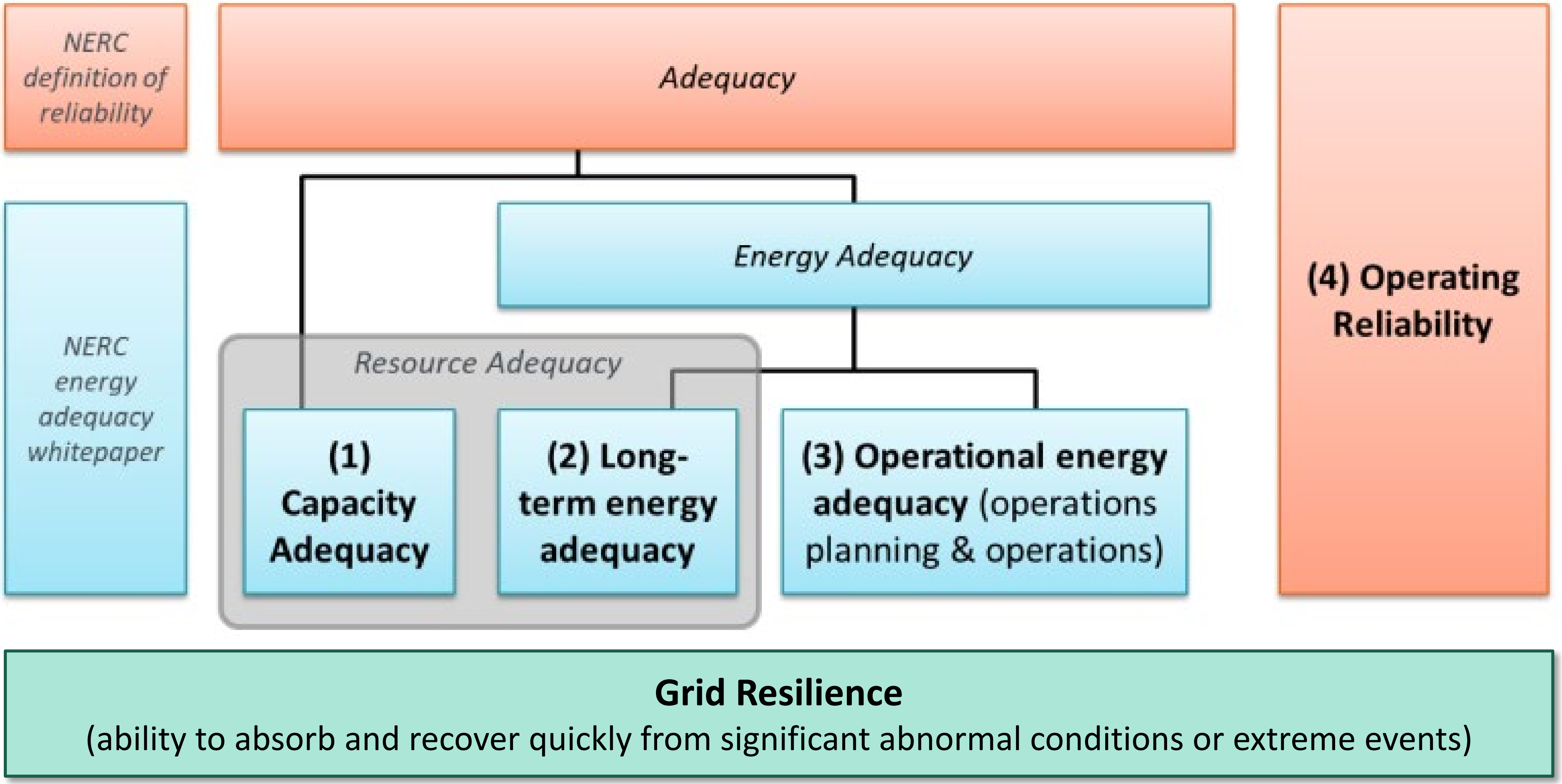


Figure 1: Risk Area Summary 2024–2028[8]

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf

High Risk: "anticipated" 2028 planning reserve margins may fall below targets (not counting prospective generation additions not yet under construction or the RA value of non-firm resources and imports without firm contracts)

Defining Adequacy, Reliability, and Resilience



See: Celebi, Levitt, Bulk System Reliability for Tomorrow's Grid (Brattle, December 2023)

How to Maintain Resource Adequacy and Operational Reliability?

Addressing capacity needs and replacements reliably and cost-effectively is both challenging and possible! These transition-related challenges can be addressed:

A. Let resource adequacy frameworks evolve with the changing resource mix

B. Don’t discount the effectiveness of market responses

C. Keep modern gas plants to support resource adequacy in a clean-energy grid

D. Develop demand flexibility, including as a dispatchable resource (VPPs)

E. Take advantage of the grid-supporting capabilities of new inverter-based resources

F. Speed up generation interconnection processes, particularly for replacements

G. Expand regional markets and more proactive/holistic transmission planning

A. Evolving Design of Resource Adequacy Framework

As the resource mix changes, RA frameworks will need to be updated. Annual "peak load plus planning reserve margin" will not be sufficient:

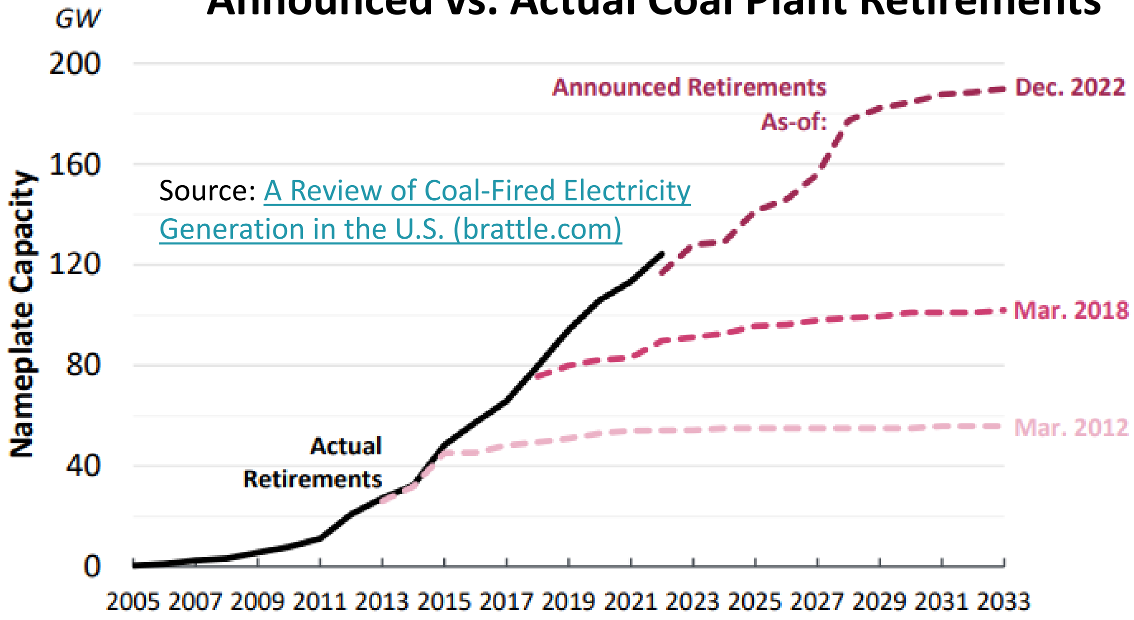
1. RA frameworks will require seasonal focus
   - Increasingly challenging system conditions: heat waves, cold snaps, renewable droughts
   - Seasonally correlated generation availability and forced outage rates
2. RA challenges shifting away from peak load hours
   - Hours with highest net loads (early morning/evenings)
   - Hours with low "supply cushions" (e.g., during renewable droughts)
3. Need for improved capacity accreditations
   - Average and marginal ELCC
   - RA value of uncommitted (non-firm) resources and interties
4. Improved RA metrics: LOLE ➔ EUE
5. Decentralization of resource adequacy, grid reliability, and resilience:
   - Will shift from provided by the <u>centralized</u> grid <u>to</u> rely more on <u>distributed</u> generation and storage resources
   - Role of the grid will shift from instantaneously delivering energy+capacity to delivering energy on a daily basis from a geographically-diverse set of resources

B. Don’t Discount the Effectiveness of Market Responses

Can’t underestimate the challenge, but we’ve been there before!

- A decade ago: significant resource adequacy concerns over mercury regulation of coal plants
- Market response prevented doomsday projections from being realized
- Example: PJM capacity market easily replaced retiring plants with range of replacement resources (DR, imports, gas)

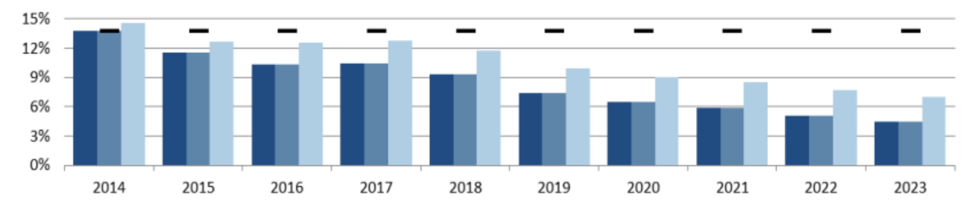
Announced vs. Actual Coal Plant Retirements



Also note: NERC projections often not realized:

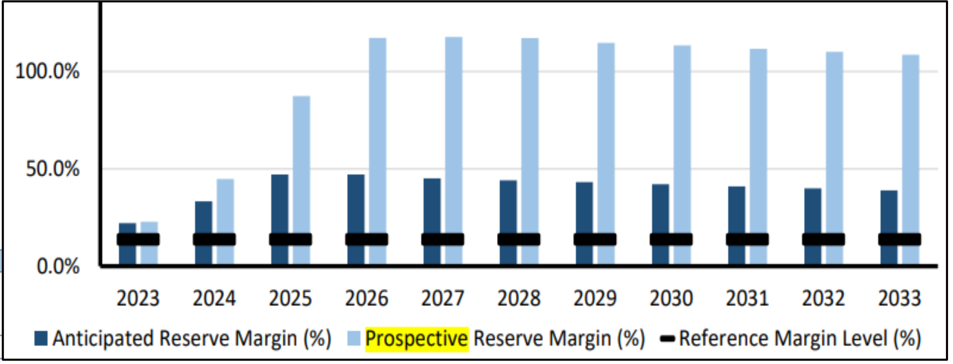
NERC **2013** Long-term Assessment for ERCOT

Figure 11: TRE-ERCOT Planning Reserve Margins



TRE-ERCOT-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		13.74%	11.59%	10.34%	10.46%	9.34%	7.36%	6.44%	5.91%	5.11%	4.43%
PROSPECTIVE		13.74%	11.59%	10.34%	10.46%	9.34%	7.36%	6.44%	5.91%	5.11%	4.43%
ADJUSTED POTENTIAL		14.58%	12.71%	12.53%	12.71%	11.75%	9.98%	9.04%	8.49%	7.67%	6.97%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

NERC **2023** Long-term Assessment for ERCOT



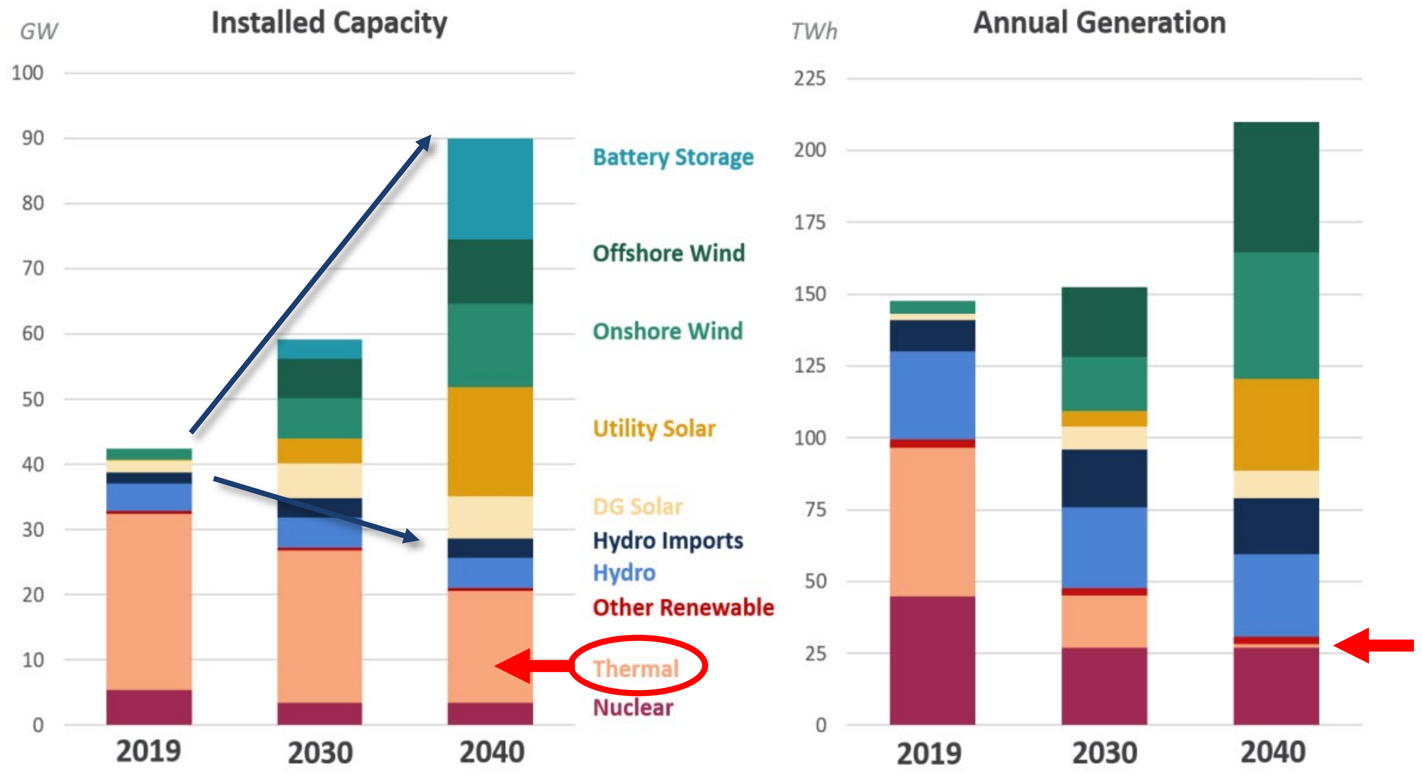
C. Keep Modern Gas Plants to Support Resource Adequacy

Modern natural gas plants that could be converted to renewable natural gas, biofuels, or hydrogen will be an effective solution for maintaining resource adequacy even in a deeply decarbonized power grid

Example: New York Power Grid Study (70% emissions free by 2030, 100% by 2040)

2040 Results:

- Installed capacity more than double today's
- 10-15 GW each onshore wind, offshore wind, solar, and storage
- 17 GW of "thermal" backup generation fueled by renewable natural gas (as placeholder until more clarity exists about future technologies) to address reliability challenges (incl. renewable droughts)

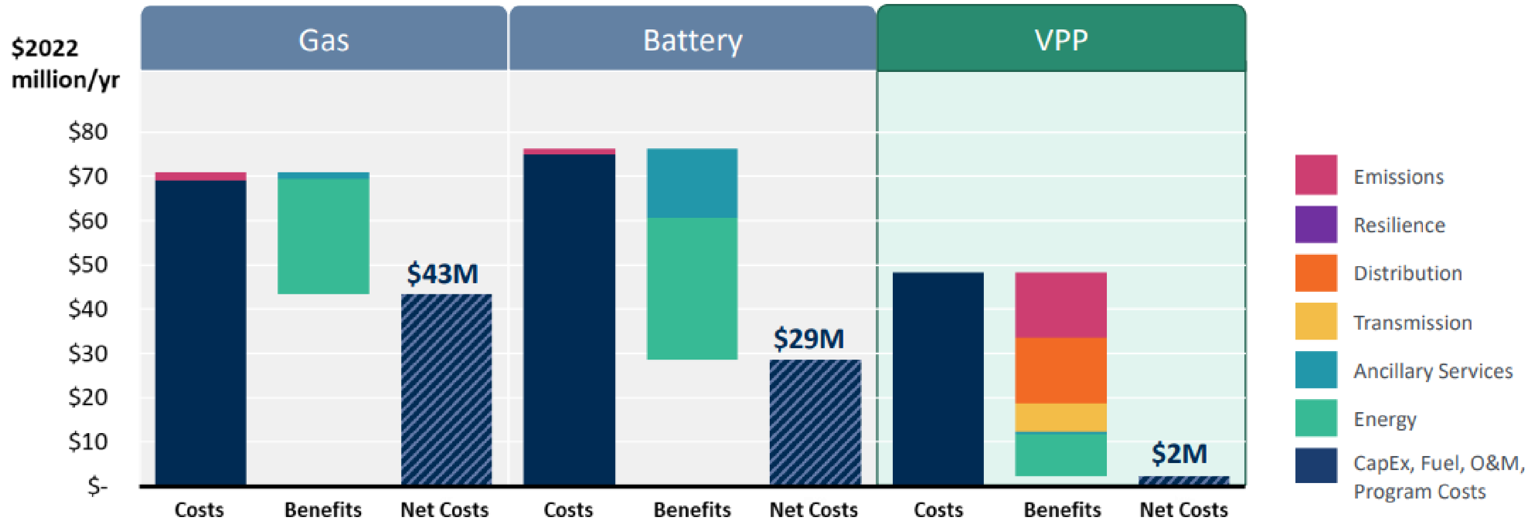


D. Demand Flexibility and Virtual Power Plants (VPPs)

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>
  - Examples: Electric Vehicle (including V2G), building HVAC, thermal storage, solar+storage
- 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
  - VPPs offer resource adequacy at (1) significantly <u>lower cost</u> and (2) <u>without delays</u> in generation interconnection

Annualized Net Cost of Providing 400 MW of Resource Adequacy



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

E. Grid-support from Modern Inverter-Based Resources

Inverter-based resources (IBRs) can create grid reliability challenges that need to be addressed through improved interconnection standards

However, in addition to <u>preventing reliability problems</u>, new IBR standards should be designed to <u>enable grid-supporting capabilities</u> of modern inverter technologies!

Examples:

- CAISO 2017 and 2020 pilot programs of wind and solar plants providing essential reliability services
  - Successfully provided: spinning reserves, load following, ramping, inertia, frequency response, regulation, droop response, variability smoothing, power quality, and reactive power, voltage, power factor controls
- Inertial and frequency response from wind, solar, batteries, STATCOMs, and HVDC lines
  - Quebec: Inertia provided by all wind generators
  - South Australia: 50% of inertia supplied by batteries (grid-forming inverters with “virtual machine” modes)
  - ERCOT: Primary frequency response provided by all wind and solar plants
  - UK and ENTSO-e: grid code providing for inertial and frequency response from VSC-based HVDC lines

See: 2023 HVDC report, Section V.15 (“Frequency and Inertial Response from HVDC Lines and Inverter-Based Resources”)

F. Interconnect Resources More Quickly and Effectively

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)

G. Regional Markets and More Proactive Transmission Planning

RTO experience documents benefit of large regional markets … and points to proven planning practices that can reduce total system costs and increase resilience:

1. **Proactively and holistically plan for future generation and load** by incorporating realistic projections of all needs: the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investments. Avoid siloed, incremental planning processes.
2. **Account for the full range of transmission needs** and **use multi-value planning** to comprehensively identify investments that cost-effectively address all categories of needs and benefits
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account all transmission needs for a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events
4. **Use comprehensive transmission network portfolios** to address system needs and **cost allocation** more efficiently and less contentiously than a project-by-project approach
5. **Jointly plan inter-regionally across neighboring systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits

Source: Brattle & Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (October 2021).

Thank You!

Additional Slides

About the Speaker

Johannes P. Pfeifenberger

PRINCIPAL
BOSTON

Hannes.pfeifenberger@brattle.com

+1.617.234.5624

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.

F1. Fast-track Sharing and Transfers of Existing POIs

Implement new fast-track process for sharing and transferring existing POIs to bypass long interconnection queue for new POIs

- Fast-track <u>sharing</u> of existing POIs (both surplus interconnection capacity & sharing of energy)
- Fast-track the <u>transfers</u> of existing POIs (e.g., POIs of retiring plants; POIs build through SAA)

Why?

- PJM has 40+ GW of existing POIs (with CIRs) at retiring plants! … most of which are in attractive locations for new storage, renewables (e.g., as noted in the ICC draft REAP report), and natural gas plants
  (Example: client rejected new solar+storage bid at retiring fossil plant because getting ISA would take 5-6 years)
- More quickly assign POIs built under State Agreement Approach to generators procured by states (e.g., NJ)
- Sharing POIs is attractive: many aging resources are rarely dispatched when renewable generation is high

Examples:

- Separate MISO and SPP processes for existing POIs (unlike in PJM, presumes no material impact)
- MISO "energy displacement agreements" (between existing and new resources to ensure that the total amount of shared interconnection service at the POI remains the same)

F2+3+4+5. Existing Headroom / First-ready / GETs & RAS / ERIS

- Identify "headroom" (hosting capacity, Order 2023 "heat map" requirement)
  - Example: CAISO identified interconnection requests for which 31 GW of energy-only headroom (23 GW of which are firmly deliverable) already exists without any additional network upgrades
- Fast-track generation resources that can be developed quickly (e.g., "first-ready" projects with minimal POI upgrades … beyond Order 2023 "first-ready, first-served" requirement)
  - Like PJM's "fast-lane" transition process for projects with minimal upgrades, but could be made permanent
  - CAISO's 2023 Interconnection Process Enhancements
- Allow interconnection needs to be addressed by grid-enhancing technologies (GETs) and "simple" remedial action schemes (RAS or system protection schemes, SPS)
  - GETs, such as power flow control devices, only need to be "considered" (but not used) per FERC Order 2023
  - RAS example: CAISO identified 21 GW of energy-only (16 GW of deliverable capacity) interconnection headroom that can be created quickly and inexpensively with RAS
- Simplify ERIS (energy-only) interconnection criteria for new POIs with option to upgrade to NRIS (capacity) later
  - Consider in interconnection studies the ability to manage (e.g., dispatch down) energy resources in nodal market
  - Examples: SPP ERIS, Enel working paper (speeds up energy-only interconnections to slim down the interconnection queue for firm (capacity) interconnections

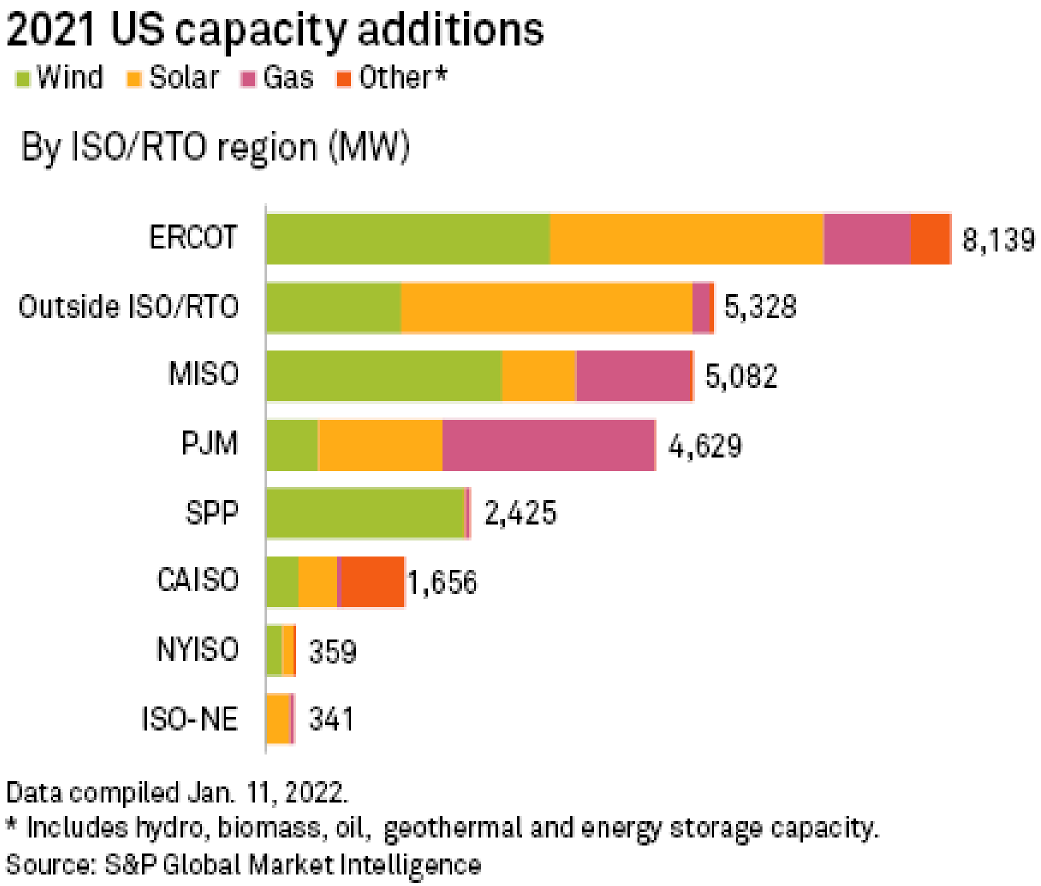
F6. Proactive, Holistic Long-term Transmission Planning

Proactively and holistically planning for long-term transmission needs can reduce total customer electricity costs and speed up interconnection of new resources

- Experience shows that simultaneously addressing all transmission needs (for generation interconnection, reliability, economic, public policy, and interregional needs) reduces costs:
  - CAISO TPP and European ENTSO-E planning and CBA framework, which includes interregional needs
  - MISO LRTP and Australian ISP (which do not consider interregional needs)
  - 2021 PJM study: $3.2b in transmission for 75 GW of clean energy resources -- shows that holistic planning for even just the next decade of generation interconnection needs would offer substantial cost reductions
- Concept: consider all near-term and long-term transmission needs (including public-policy needs through 2040-50) in approving the next decade of transmission upgrades
- Important: immediately reflect approved transmission upgrades in the "base case" for generation interconnection studies (e.g., as MISO did with approved MVPs)
- Include interregional solutions
  - Jointly plan for interconnection needs near seam (e.g., SPP-MISO JTIQ offering documented cost reductions)
  - Additionally: replace ineffective Coordinated Transaction Scheduling (CTS) with intertie optimization to improve utilization of interregional transmission and dispatch efficiency near seams, as recommended by IMM

Significant Differences in Generation Interconnection Processes

Some RTOs are able to interconnect disproportionately more generation, and have been able to do so more quickly.



RTO Size	Capacity in Queue
80 GW	135 GW
200 GW	330 GW
150 GW	155 GW
180 GW	245 GW
95 GW	100 GW
52 GW	160 GW
42 GW	75 GW
32 GW	30 GW

Planning regions with the most ambitious state clean energy standards (i.e., east and west coast states) are lagging behind regions such as Texas and the Midwest:

- ERCOT: added 10% of system capacity in 2021
- NYISO and ISO-NE: only 1%
- All others: 2-4%

See also: [Generation, Storage, and Hybrid Capacity in Interconnection Queues | Electricity Markets and Policy Group (lbl.gov)]

Five Elements of Generation Interconnection Need to be Addressed

Improving generation interconnection requires addressing all five elements of the GI process. Current discussions focused mostly on Nos. 1 and 5 (NOPR on Nos. 1 and 4)

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 through regional transmission planning?
3. **GI Study Approach and Criteria**: study assumptions, modeling approaches, and specific criteria differ significantly across regions (e.g., ERIS vs. NRIS study differences, injection levels studied, are market-based redispatch opportunities 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, are not typically considered or accepted
5. **Cost Allocation**: most 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

Option for Improving the Generation Interconnection Process

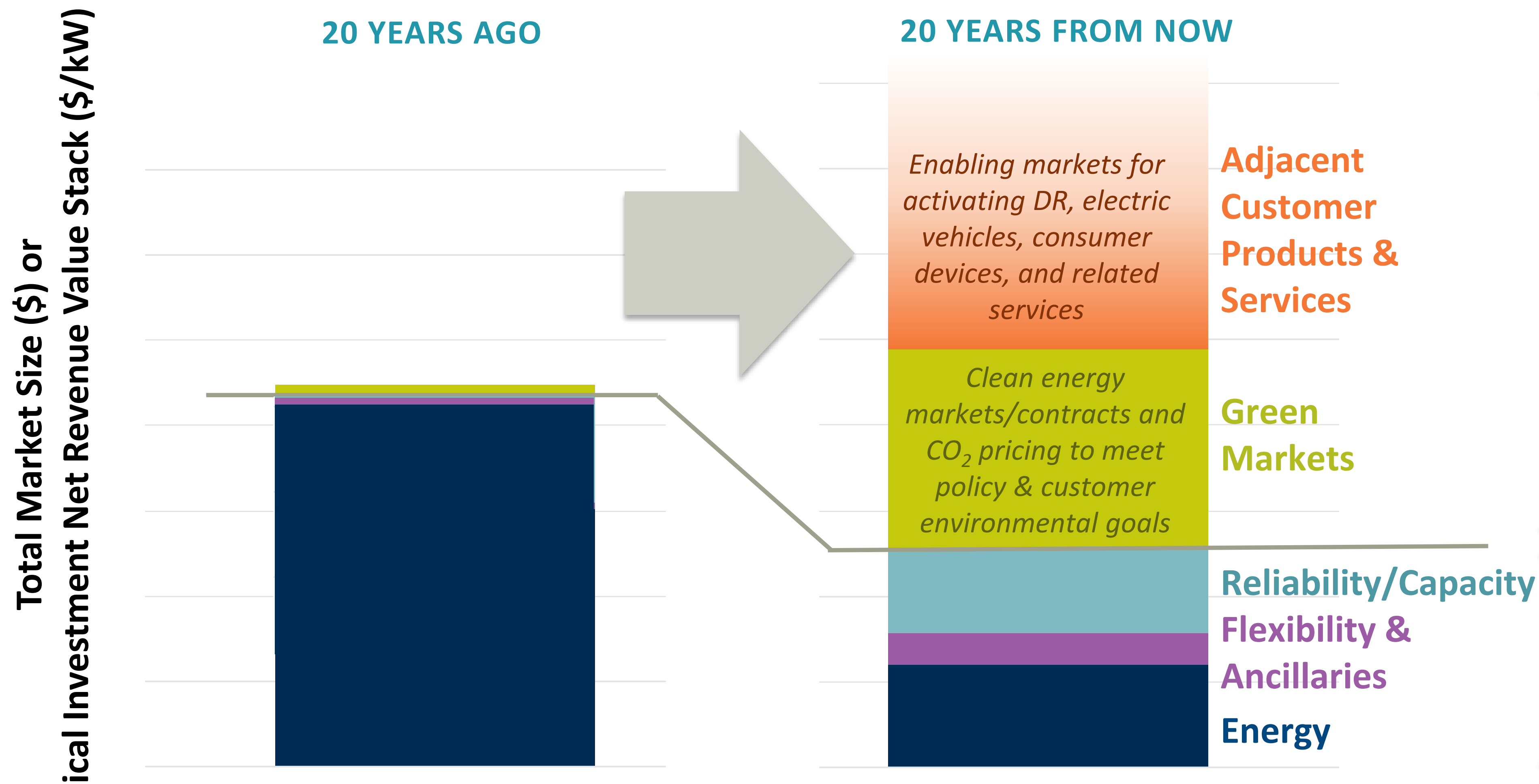
Reducing the scope of upgrades triggered by generation interconnection processes likely will be necessary to both accelerate and lower the cost of renewable interconnection:

- Attractive: UK "Connect and Manage" (replaced prior "Invest and Connect")
  - Similar to ERCOT; reduced lead times by 5 years; network constraints addressed later (e.g., with congestion management) https://www.gov.uk/guidance/electricity-network-delivery-and-access#connect-and-manage
- ERCOT's generation interconnection process is perhaps most effective in the U.S.
  - Efficient handoff of study roles by ERCOT and Transmission Owners limits restudy needs
  - Projects can be developed and interconnected within 2-3 years; in other regions, the interconnection study process itself may take longer than that
  - Upgrades focused only on local interconnection needs and are recovered through postage stamp
  - Network constraints managed through market dispatch – which imposes high congestion and curtailment risks on interconnecting generators … in part due to ERCOT's insufficiently proactive multi-value grid planning
  - See Enel working-paper.pdf (enelgreenpower.com) [Note: Brattle was not involved]

Generation interconnection based on "connect and manage" when combined with proactive transmission planning offers more timely and cost-effective solutions if:

- Near-term needs are quickly addressed through multi-value planning (beyond reliability)
- Long-term needs are proactively addressed through scenario-based long-term planning

What Might Revenues from “Future Markets” Look Like?



Current Markets

Major resources…. Dispatchable thermal plants, inelastic demand

Future Markets

Renewables, storage, EVs, DR, DER, hydro, interties, prosumers, thermal batteries

New Markets

Are needed to achieve environmental goals & mobilize customers with a wider array of tech-enabled services

Traditional Markets

Timeless principles of reliability at least cost. But must evolve to rely increasingly on “non-traditional” resources and better definitions of reliability needs

Planning & Contracts: Dos and Don’ts

Do: Emulate Others’ Successes

- **Do:** Maintain focus on strong, accurate, market signals for all system needs (energy, reliability, ancillary, green) at all timeframes (and especially closer to near-term and real time)
- **Do:** Ensure all contracted/subsidized resources have “skin in the game”, so they will seek to maximize value relative to near-term and real-time system needs
- **Do:** Maximize competition across companies and technologies in competitive solicitation processes (focus most procurements on *needed services*, rather than *specific technologies*)
- **Do:** Structure procurements to minimize reliance on planners’ forecasting accuracy and qualitative judgements
- **Do:** Allocate risks where they belong. Developers can continue to bear the risks under their ability to manage and control, e.g.: failed technology, delayed schedules, poor operational performance, fuel prices, supply chain interruptions
- **Do:** Let customers self-supply (but without free riding on reliability). They may find cheaper alternatives
- **Do:** Eliminate barriers to entry and participation for new technologies that can be activated to “do more”

Don’t: Make the Common Mistakes

- **Don’t:** Offer 100% contracts to 100% of resources – need to leave room for market discipline to correct for planners’ forecasting uncertainties
- **Don’t:** Believe the “base case” forecast. Long-term planning is about decision-making in uncertainty (“least regrets” resource mix will outperform the best “base case” resource mix)
- **Don’t:** Let sellers get lazy with “contract and forget” structures
- **Don’t:** Pay sellers for injecting power where or when it has no value (zero or negative price intervals, places where injections are curtailed)
- **Don’t:** Put all the eggs in one basket (going all-in on one technology or high-risk megaproject) without putting it to the “market test” (put out the call: can any one else solve the same problems at a lower cost?)
- **Don’t:** Shift investment risks to customers unless there is a good reason (e.g.: identified market failure, systemic risks, inefficient regulatory risk)
- **Don’t:** Underestimate what creative companies and customers can do. They will nearly always find an easier, better, or cheaper answer to a well-defined problem

Additional reading: Chapter III of South Carolina Market Reforms Study; Chapter 3 of EU Market Review Study.

Brattle Group Practices and Industries

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- 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
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- Renewable & Alternative Energy

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