

Transmission Planning with Large Loads

Current Practices and Recommendations

A REPORT BY THE ENERGY SYSTEMS INTEGRATION GROUP'S
LARGE LOADS TASK FORCE

PREPARED BY

Johannes Pfeifenberger

Warren Lasher

James Okullo

PRESENTED TO



NARUC

National Association of
Regulatory Utility Commissioners

APRIL 16, 2025



Agenda / Outline

1. Introduction: Why Large Loads Are a Transmission Planning Challenge
2. How Transmission Planning Works Today: A Primer
3. Three Core Challenges: Silos, Speed, and Uncertainty
4. Actionable Recommendations:
 - Part I: Immediate Actions
 - Part II: Near-Term Process Fixes
 - Part III: Longer-Term Structural Solutions
5. Summary of Phased Best Practices
6. Conclusions and Key Takeaways

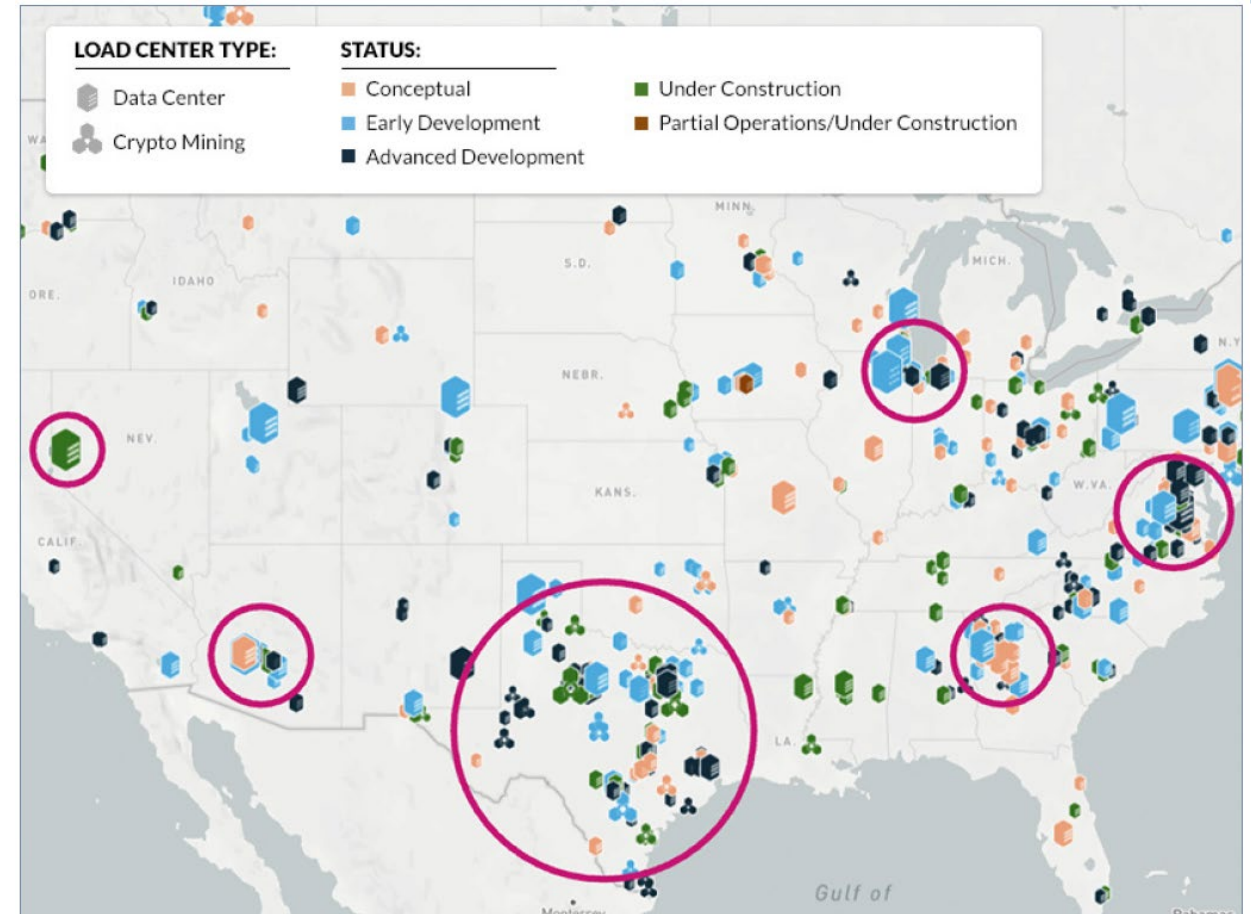
The Scale of the Large Load Challenge

Context:

- U.S. electricity systems face a surge of proposed large loads - primarily data centers - materially different in scale and speed from historical demand growth
- DOE predicts a 25% rise in electric demand by 2030; data center demand may double or triple by 2028
- Individual facilities often exceed 500 MW - comparable to medium-sized urban load centers - with large numbers concentrated in specific geographic areas
- As of January 2026, ERCOT alone had 92 large load projects greater than 1 GW in its interconnection queue

Current planning processes were designed for steady, limited growth - They are a poor fit for loads that develop quickly, affect multi-regional grids, require major new infrastructure, and are difficult to forecast

High Levels of Geographically-Concentrated Data-Center Grid-Interconnected Demand



Source: YesEnergy, "[Tracking the Rapidly Transforming Power Grid](#)," December 12, 2025.

Why This Matters

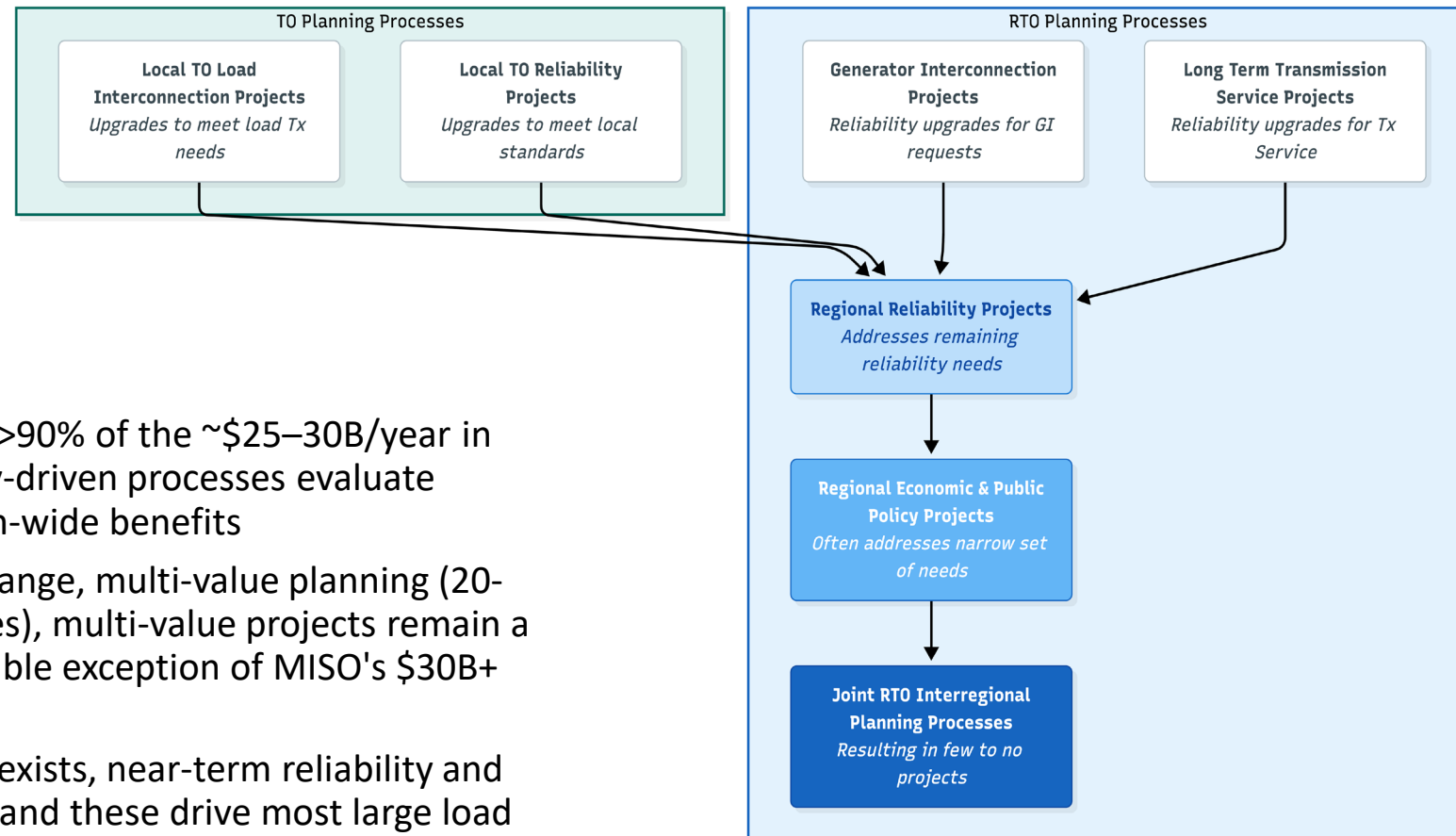
- Insufficient transmission capacity leads to reliability challenges, interconnection delays, and higher congestion costs
- New transmission takes up to a decade to plan and build; poor decisions are expensive and long-lived for ratepayers
- Improved grid planning (including reliance on available near-term options) can both support "speed to market" objectives, better support long-term needs, and address affordability concerns.

Well-planned transmission improves reliability, lowers generation costs, and reduces delivery costs - every \$1 billion in well-planned upgrades may reduce other electricity system costs by \$2–3 billion

How Transmission Planning Works Today

- Most planning focuses on local/regional reliability needs over the next decade, using a single “base-case” forecast for challenging (90th percentile) summer and winter peaks
- Planning is siloed into separate processes—each with its own objectives, assumptions, and timelines: load interconnection, generator interconnection, reliability, economic/public policy, and near- vs. long-term planning
- Local/regional reliability projects account for >90% of the ~\$25–30B/year in U.S. transmission investment; these reliability-driven processes evaluate project costs but rarely assess broader system-wide benefits
- While FERC Order 1920 now mandates long-range, multi-value planning (20-year studies, 3+ scenarios, 7 benefit categories), multi-value projects remain a small share of total investment, with the notable exception of MISO's \$30B+ in LRTP approvals
- Even where multi-value, long-range planning exists, near-term reliability and interconnection processes remain separate—and these drive most large load transmission decisions today

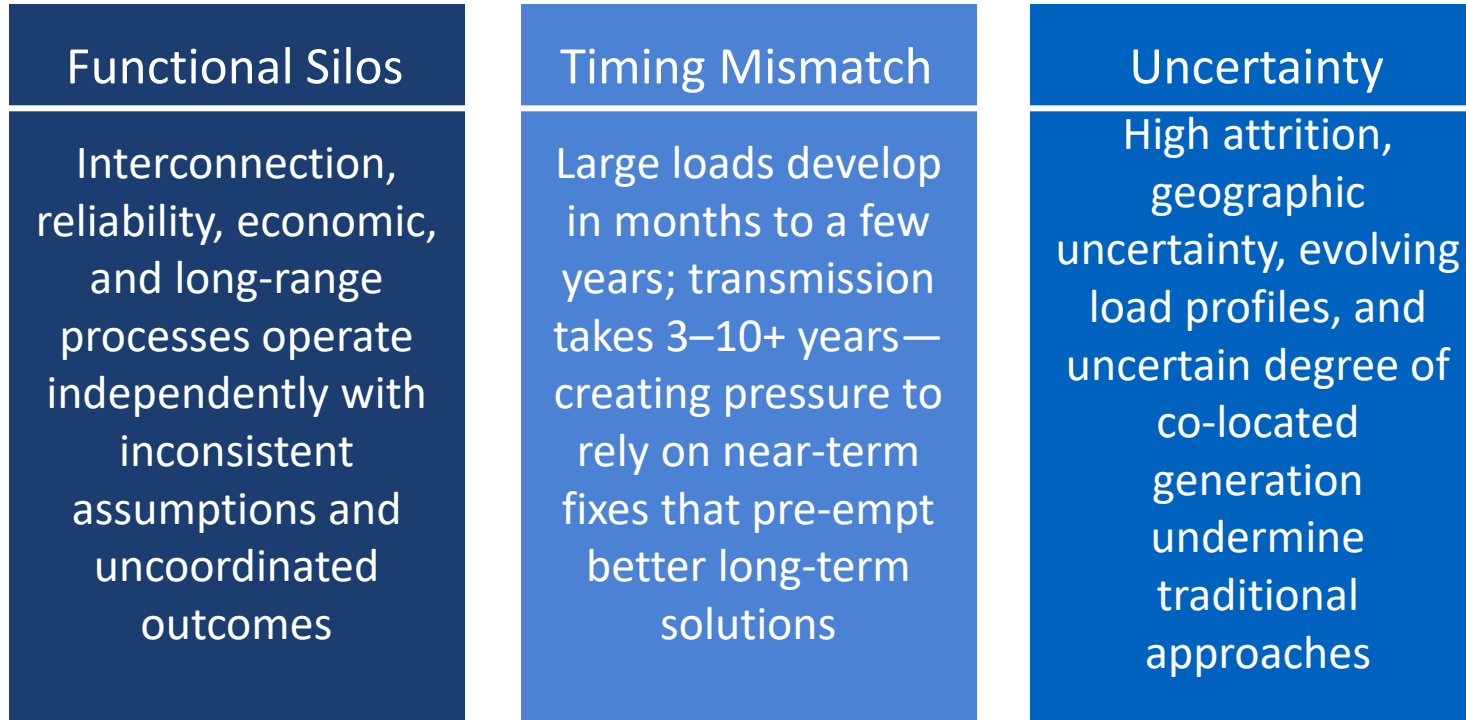
Typical U.S. Transmission Planning Processes in RTO Regions



Source: The Brattle Group

Three Core Challenges - Overview

- Large load growth is revealing three structural weaknesses in existing grid planning:



- These challenges compound: silos block information sharing; urgency drives preference for available quick fixes; uncertainty makes base-case planning unreliable

Challenge #1—Functional Silos



- When planning functions are siloed, large load interconnection decisions shape infrastructure investments without being evaluated against the broader system needs, flexibility, or total cost
- Silos were tolerable when demand growth was limited. Today, a single large load can simultaneously challenge local reliability, regional power flows, congestion, and long-term resource adequacy
- Path dependence: Near-term reliability upgrades quickly become part of the modeled baseline. Shifting the cost-effectiveness of attractive subsequent solutions, which may become infeasible
- Each individual upgrade may look reasonable, but the sequence makes higher-value, longer-term solutions harder to justify. The total costs of piecemeal upgrades exceeds that of a holistic solution.
- Regulatory structures tend to encourage local, utility-driven solutions through siloed processes; coordinated regional planning takes longer and can trigger extended cost-allocation challenges

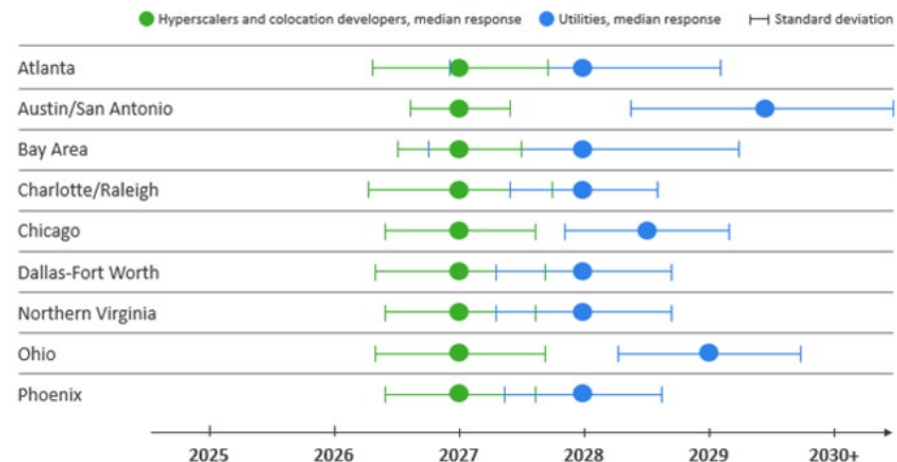
Challenge #2—Timing Mismatch

Planning, Permitting, and Construction Timelines for Transmission and Supply Measures Compared to Large Load Development

- Fast data center timelines: months to a few years.
- Slow grid processes:
 - Transmission planning and construction: 3–10+ years
 - Load and generator interconnection: studies alone take years and constructing the necessary upgrades add years for permitting, siting, procurement, and construction
- Result: persistent pressure to serve new load at a pace faster than the grid expansion can deliver. Quick fixes are chosen that undermine more effective solutions
- Inefficient grid expansion: Interim upgrades are justified as bridges but, once energized, the “quick fixes” reduce the cost-effectiveness of larger projects—which makes efficiently-sized reinforcements harder to approve, and the system accumulates a patchwork of incremental fixes at higher total cost

Differing Expectations About Speed to Power Between Data Centers and Utilities

Data center developers are more optimistic in grid power delivery timelines than utilities¹
Data center market expectations of the earliest a utility can provide power

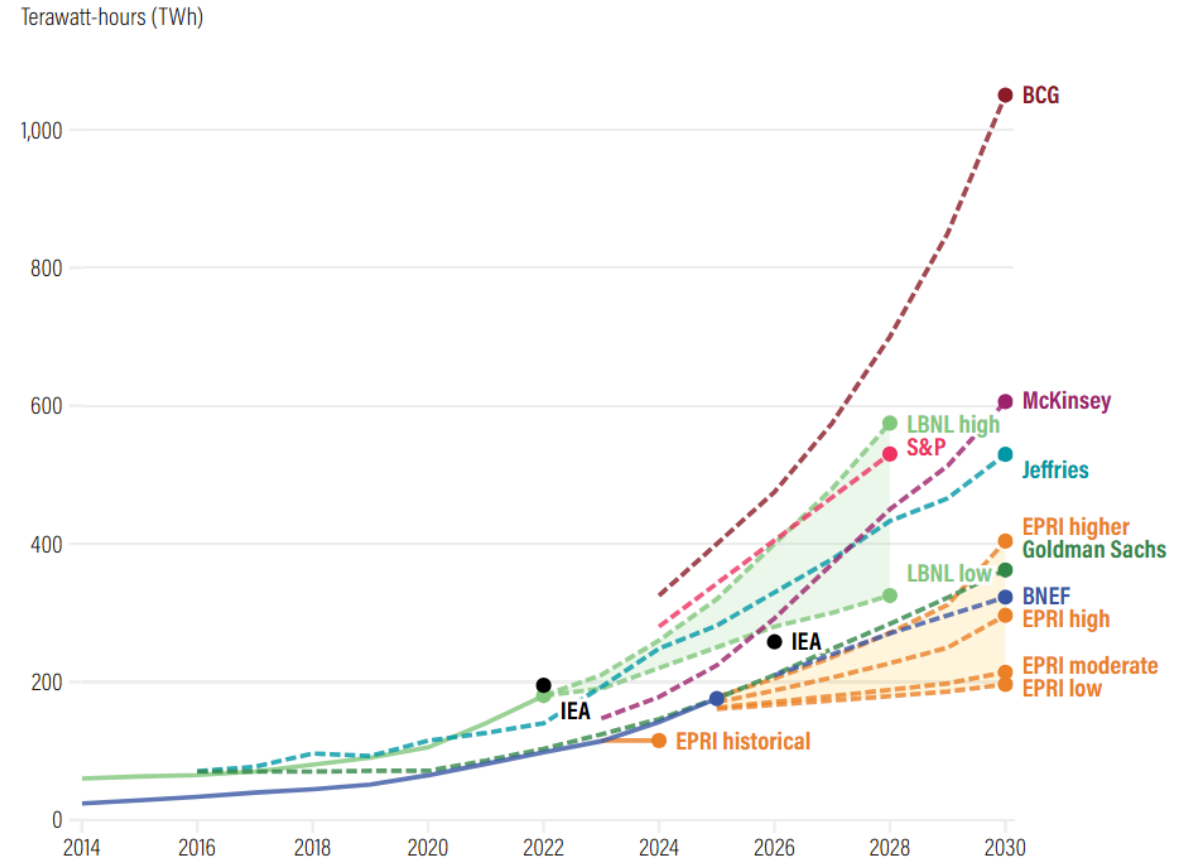


¹ Survey question: In key data center markets, when is the earliest a utility could give you power?
Source: Survey of data center decision makers (hyperscalers and colocation developers, n=44; utilities, n=23 in April 2023)

Challenge #3—Uncertainty

- Large loads introduce fundamentally different uncertainty—lumpy, location-specific, fast-moving, and driven by commercial/technology/policy decisions outside planners' control
- Key uncertainties change net grid impact: whether a project materializes (realization risk), where it will succeed (location uncertainty), when it energizes (schedule risk), ramp speed (usage risk), and whether it will be co-located generation (net impact uncertainty)
- Demand forecasts show an extraordinarily wide range—in ERCOT, 232 GW of large loads sought interconnection by 2030, but the operator included only ~50 GW in its 2025 planning cycle
- A single base-case forecast is no longer sufficient—uncertainty must be treated as a core planning consideration

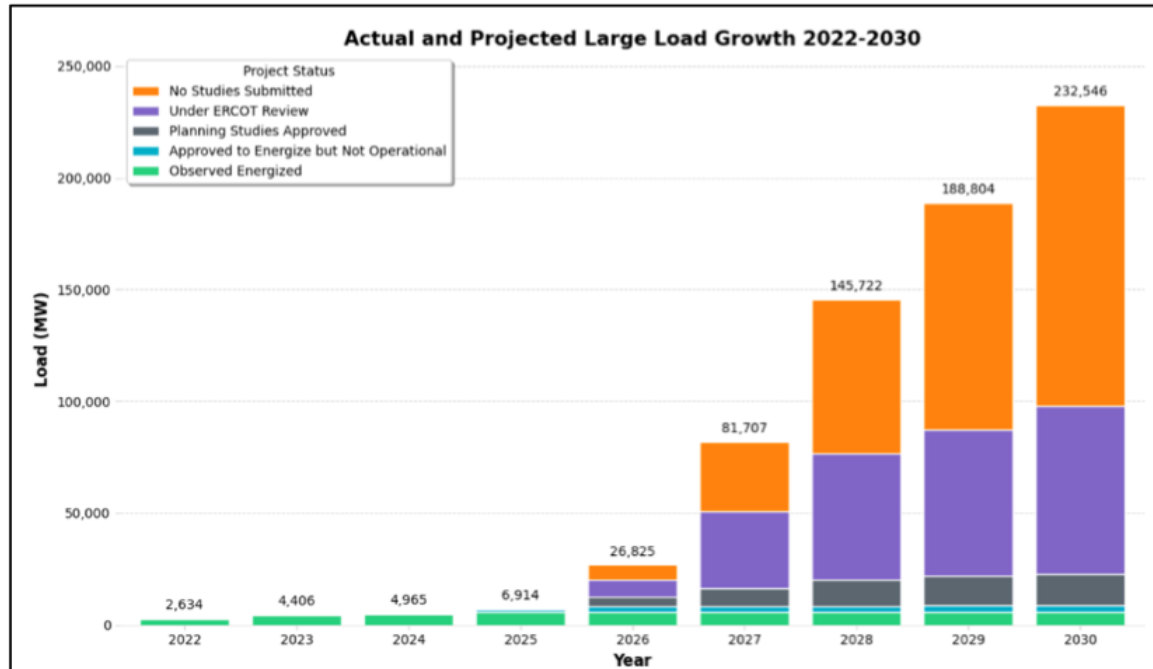
Comparison of U.S. Data Center Electricity Demand Forecasts



Source: Ian Goldsmith and Zach Byrum, "Powering the US Data Center Boom: Why Forecasting Can Be So Tricky," World Resources Institute, September 17, 2025.

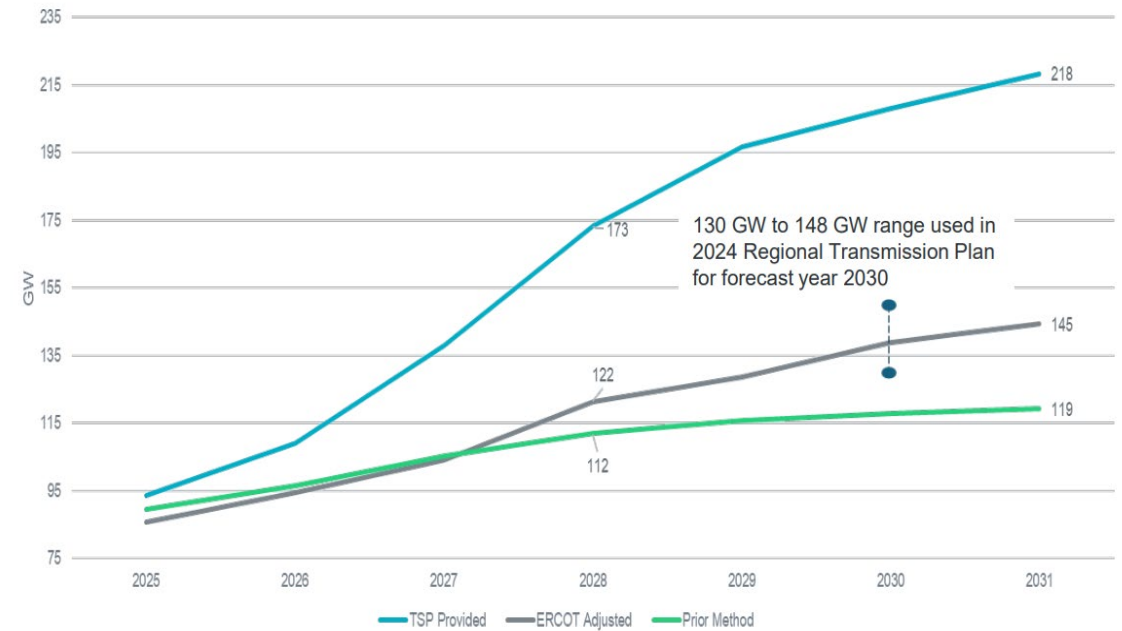
Challenge #3—Uncertainty

Actual and Projected Large Load Projects in ERCOT from 2022–2030



Source: "ERCOT Monthly", January 2026

ERCOT's Forecasts of Total Electricity Demand

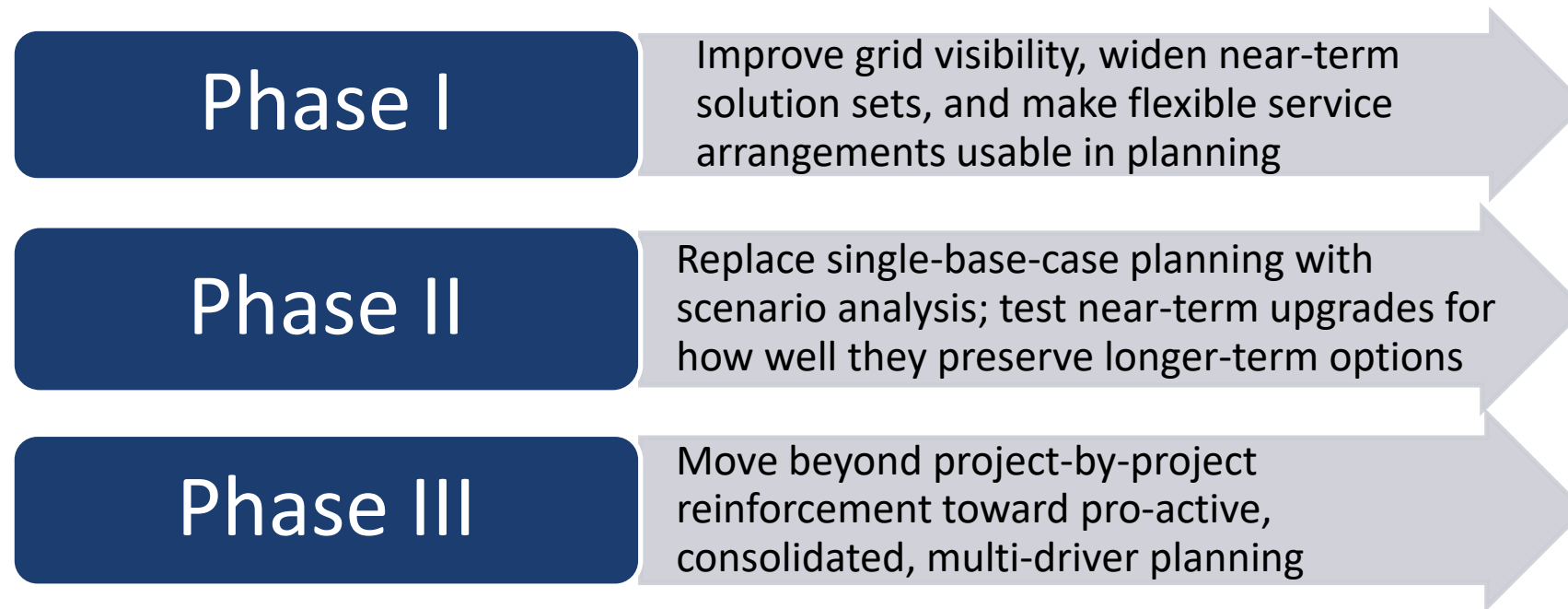


Source: ERCOT. Slide 10 of [Item 8.1: Long-Term Load Forecast Update](#)

From Challenges to Solutions—Recommendations

Current planning processes must be revised to address the core challenges identified

- Recommendations are organized in three (parallel) phases:



- The goal is to identify (1) what regions can do now for near-term results, (2) what process changes are capable to yield improved intermediate-term results, and (3) what structural changes are needed if growth continues for better long-term planning results.

Part I - Headroom Visibility and Near-term Tools

- Grid visibility: Improve and publish where on the existing grid load can be served, and under what conditions—planners and developers currently discover constraints too late
 - Headroom studies should cover multiple operating conditions (summer, winter, net-peak, shoulder, light-load, high-transfer) and multiple service structures (firm, non-firm, with/without RAS, with/without co-located resources)
 - Results should be public, consistent, and stakeholder-oriented—distinguishing fast-service areas from areas requiring material new transmission
- Grid-enhancing technologies (GETs): Topology optimization, power flow controls, dynamic line ratings—new capacity in months at far lower cost
- Advanced transmission technologies (ATTs): High-performance conductors can double line capacity without new towers
- Operational controls such as remedial action schemes (RAS) can accelerate interconnection by creating headroom on the existing grid (but must be well-defined, rigorously studied, and carefully governed)

Part I—Flexibility, Co-Location, Shared Assumptions, Automation

LOAD FLEXIBILITY

- Large loads can reduce grid-facing demand via load adjustments, backup generation, storage, or co-located generation—but should only be credited in planning when operationally enforceable and reflected in interconnection agreements

CO-LOCATION

- Co-located loads and generation ("energy parks"): Controllable hybrid (load + generation) facilities that limit net grid impacts to they can quickly—SPP's HILLGA framework, MISO's proposed ZGIA process, PJM's NF-CDS, and ERCOT BYOG/PCLR are exploring these models

SHARED ASSUMPTIONS

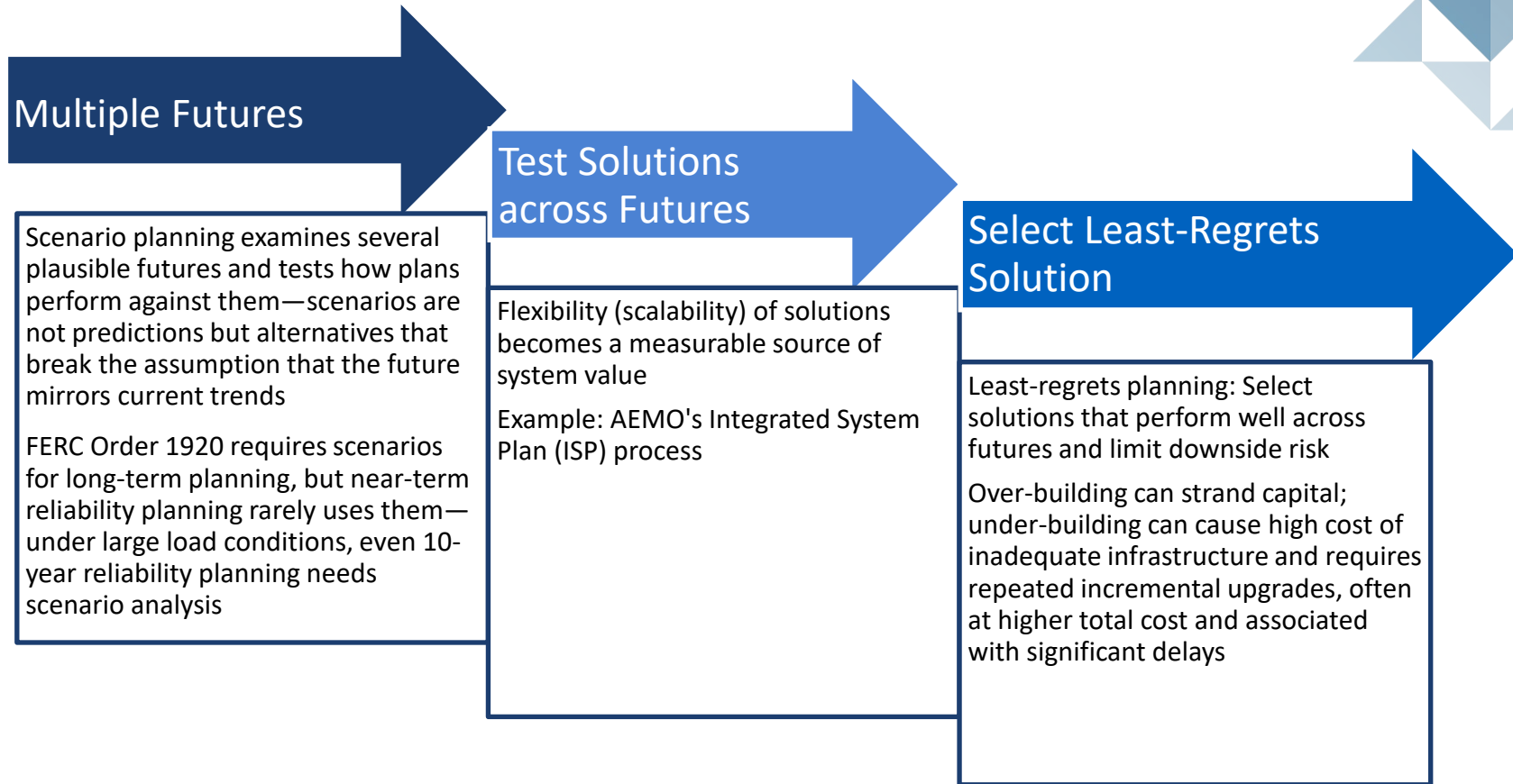
- Shared assumptions: A common, version-controlled large-load dataset should be used across interconnection, reliability, and long-range studies—not separate assumptions for each planning function
- Common scenarios of plausible futures should bracket projected uncertainties

AUTOMATION

- Modernize and automate study workflows to reduce manual bottlenecks

Part II—Scenario-Based and Least-Regrets Planning

- The base case can no longer be treated as a "best estimate" for designing transmission solutions—large load uncertainty demands a different approach
- Use “futures-based” planning for uncertainty, which other industries have employed for decades



Under-building in the face of uncertainty can be more costly than over-building. Best to commit to a flexible, scalable solution

The Math of Least-Regrets Planning—An Example



- Example: Future interconnection needs range from 800 MW to 1,600 MW to 2,400 MW across three scenarios
- Three solutions:
 - **A: Single-circuit 500kV**—\$500m (optimal for 800 MW)
 - **B: Double-circuit 500kV**—\$600m (optimal for 1,600 MW; can operate as single circuit initially)
 - **C: 765kV**—\$800m (optimal for 2,400 MW; can operate at 500kV initially)
- If Solution A is chosen but 2,400 MW materializes, ultimate cost reaches \$1.1b (highest total cost outcome)
- Solution C has the least regret: max regret of \$200m vs. Solution A's max regret of \$400m
- **Takeaway: The "least-cost" option carries the greatest regret risk; flexible, scalable solutions reduce the cost of being wrong**

Planning for Interconnection Needs in Three Scenarios

	<u>Future 1</u>	<u>Future 2</u>	<u>Future 3</u>
Need	800 MW	1600 MW	2400 MW

Optimized Transmission Solutions

Solution A	1x500kV			single-circuit 500kV line is optimal for Future 1 double-circuit 500kV line is optimal for Future 2 (can initially be operated as single circuit) 765kV line is optimal for Future 3 (can initially be operated at 500kV)
Solution B	2x500kV			
Solution C	765kV			

Cost of Optimized Solutions

Cost A	\$500m			(\$550 if initially built as single-circuit line on double-circuit towers) (\$650m if operated at 500kV initially; plus \$150m for transformation)
Cost B	\$600m			
Cost C	\$800m			

Evaluation of How Each Solution Performs in All Three Futures

	<u>Future 1</u>	<u>Future 2</u>	<u>Future 3</u>
Outcome if Actual Future is different from Optimized			
Solutions A+	1x500kV	+1x500kV	+2x500kV
Solutions B+	op as 1x500kV	2x500kV	+1x500kV
Solutions C+	op at 500kV	765kV	765kV

Need to add another 500kV line (or 2x500kV line) if Future 2 (or Future 3) is realized
Need to add another 500kV line if Future 3 is realized; solution oversized for Future 1
Solution oversized in Futures 1 and 2; operated at 500kV in Future 1 (saves \$150m in transformation)

Ultimate Cost

Cost A+	\$500m	\$1000m	\$1100m
Cost B+	\$550m	\$600m	\$1100m
Cost C+	\$650m	\$800m	\$800m

Weighted Average Cost

\$866m
\$750m
\$750m

Other considerations

ROW for up to 1x500kV and 2x500kV
ROW for up to 2x500kV plus 1x500kV
ROW for single 765kV line only

	<u>Future 1</u>	<u>Future 2</u>	<u>Future 3</u>
Maximum Regret (i.e., added cost of being wrong)			
Regret A	0	+\$400m	+\$300m
Regret B	+\$50m	0	+\$300m
Regret C	+\$150m	+\$200m	0

Regret: up to \$400m extra due to underbuilt solution
Regret: \$300m extra due to underbuilt solution for F3; \$100m overbuilt in F1
Regret: up to \$200m due to overbuilt system

Flexible Transmission Solutions / Benefit-Cost Analyses

- **Flexible 230kV aging line rebuild:**

- Standard rebuild: \$800m
- "345kV-ready" with double-circuit towers: +\$100m
- Later conversion to 345kV adds 1 GW headroom for +\$100m
- Second circuit can be added for \$150m
- Total Cost: \$1b to \$1.15b

Without proactive design: spend \$800m on rebuilt then a later add greenfield lines at \$1–2b

- **CAISO HVDC-ready design:** Interconnect 1,600 MW of offshore wind with option to scale to 3,300 MW and 8,000 MW via "HVDC-ready" 500kV design and pre-acquired rights of way
- **ERCOT CREZ:** Single-circuit lines with double circuit towers were not cheapest solution, but offered fast and cost-effective expansion

Scenario-based Benefit-Cost Analysis:

- For interconnection and reliability-driven projects, scenario-based, least-regrets planning can focus on project costs (as in the examples discussed so far).
- To implement scenario-based least-regrets planning in the context of multi-value solutions, the focus needs to shift from reducing costs to maximizing net benefits (to minimize total system costs)
- **Example: ATC's analysis of Paddock-Rockdale line**
 - Scenarios presenting 6 plausible futures
 - Multi-benefit analyses similar to Order 1920 requirements
 - Benefits fell \$56m short of \$136m project cost in one scenario; but savings exceeded project costs by \$100-700m in other scenarios
 - Result: \$375m in average savings across scenarios
 - ▶ Maximum regret of building the project: \$56 million
 - ▶ Maximum regret of not building it: \$700 million

Part III—Proactive Holistic planning ... Development zones

Request-by-Request Planning (fragmented, costly)

- Current planning processes:
 - Identify grid upgrades for individual clusters of generator interconnection request
 - Identify grid upgrades for (mostly individual) load interconnection requests
 - Identify grid upgrades for other immediate and 5-10 year reliability needs under current “base case” projections

Result: a piecemeal, fragmented grid expansions that tends to cause delays and be more costly in the long-term

When the number of individual requests stack up, the question shifts: keep responding with incremental upgrades or plan around longer-term growth and a broader set of future transmission needs?

Proactive, Holistic Planning (planned, scalable)

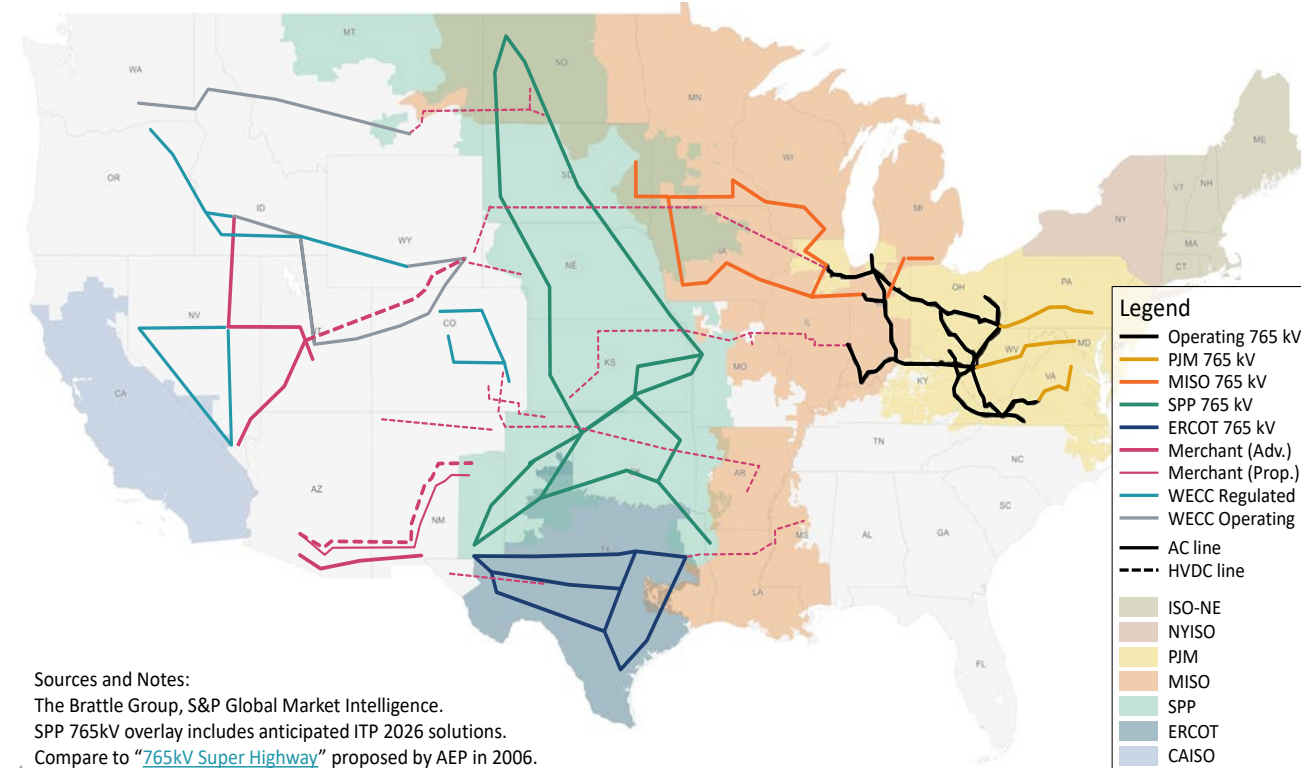
- Proactively address needs: jointly plan for all projects in an area that meet objective milestones—eliminate individual studies and restudies; identify more cost-effective “at scale” solutions
- Holistic, multi-value planning: Size solutions for full long-term range of plausible needs with staged expansion—more robust solutions that reduce need for piecemeal incremental upgrades
- Take advantage of development zones

Development zones: Work with state policy makers to designate development zones for large loads and generation (modeled after Texas CREZ or Illinois REAP) to reduce locational uncertainty and enable proactive grid planning

Part III—Coordinated Interregional Planning

- Full consolidation or siloed local and regional remains uncommon
 - SPP's proposed Consolidated Planning Process (CPP) is the exception. It would replace separate planning process and enable proactive creation of projected transmission capacity needs
 - SPP's CPP is proposed to include interregional planning
- Interregional value has to be considered explicitly:
 - Resource adequacy, extreme weather resilience, and energy trading of interregional projects offers unique value in addition to also addressing regional and local needs
 - Regional 765kV overlays in MISO, PJM, SPP, and ERCOT could be linked to support future interregional transfers and add and large load interconnection headroom
- Interregional solutions should be also evaluated for addressing identified all local/regional needs so they are not preempted by local/regional projects
- Challenges remain: multi-regional planning complexity, cost allocations, and multi-jurisdictional permitting

Planned and Proposed High-Voltage Transmission Overlays and HVDC Lines



Source: Pfeifenberger, [Interregional Transmission and Benefits from Improved Planning](#), December 2025. Note that the northern portions of SPP's proposed 765kV overlay have been proposed for SPP's 2026 planning cycle but are not yet approved. The shown "operating" and proposed "regulated" transmission projects in WECC are operated at 500 kV.

Summary—Phased Best Practices (Phases 1 & 2)

Phase 1

1. Maximize existing assets; minimize lock-in of bad decisions
2. Measure and publish near-term headroom and locational signals
3. Deploy GETs, ATTs and operating measures to address immediate needs
4. Credit flexibility and co-location (when operationally enforceable)
5. Use a common set of scenarios and large-load projections and across all studies
6. Adopt a proactive, consolidated study process before piecemeal investments lock in more costly outcomes
7. Automate work flows and study processes

Phase 2

1. Use scenarios representing plausible future to bracket projected uncertainties in every planning cycle
2. Develop least-regrets metrics for comparing solutions across multiple futures to value flexibility and mitigate the risk of under/over investment
3. Link interconnection, reliability, near-term and long-term planning for developing more robust solutions
4. Confirm that solutions are "future-proof" before approving major upgrades—document whether cost-effective expansion options are preserved

Summary—Phased Best Practices (Phase 3)

Phase 3

1. Build holistic grid solutions that address transmission needs beyond individual interconnection requests; identify and stage backbone projects
2. Encourage and take advantage of "development zones" for large loads and generation (such as CREZ, REAP)
3. Implement consolidated (multi-driver) planning
4. Evaluate local, regional, and interregional solutions for their ability to holistically address all identified needs
5. The shift required: evolve deterministic, base-case-driven planning to holistic, scenario-based, least-regrets decision-making—not abandoning existing frameworks, but using them to holistically address all projected transmission needs

Conclusions and Key Takeaways

- Large loads are arriving far faster than planning and infrastructure can serve them—that gap is not closing
- Current planning processes—built for slow, predictable growth—are structurally mismatched to loads that are large, fast, clustered, and uncertain
- Siloed planning processes, development speed mismatches, and uncertainties compound one another, tempting regions to rely on reactive, piecemeal fixes that lead to delays and higher costs
- The path forward:
 - Create headroom visibility and deploy a wider set of available near-term solutions
 - Rely on proactive scenario-based planning and least-regrets decision-making—even for near-term decisions
 - Develop scalable, flexible grid solutions that preserving future expansion options
 - Deploy holistic (including interregional) planning and solutions instead of reactive, piecemeal approaches
 - Develop shared assumptions and automate workflows across all planning functions
- Implementable through phased actions—requires collaboration among regulators, planners, utilities, and states

Plan for speed and long-term flexibility—not project-specific, short-term workarounds that increase costs and limit long-term options

Thank You! Comments and Questions?



Johannes P. Pfeifenberger

PRINCIPAL | THE BRATTLE GROUP

Hannes.Pfeifenberger@brattle.com

+1 (617) 320-5135



Warren Lasher

PRESIDENT | LASHER ENERGY CONSULTING

warren@lasherenergy.com

+1 (512) 762-3389



James Okullo

DIR OF SYSTEM PLANNING | ESIG

james@esig.energy

+1 (971) 258-7891