



SPP and Data Centers

2026 Nebraska Power Summit

Steve Purdy

Technical Director, Engineering Policy



*Working together to responsibly and economically
keep the lights on today and in the future.*



SouthwestPowerPool



SPP.org



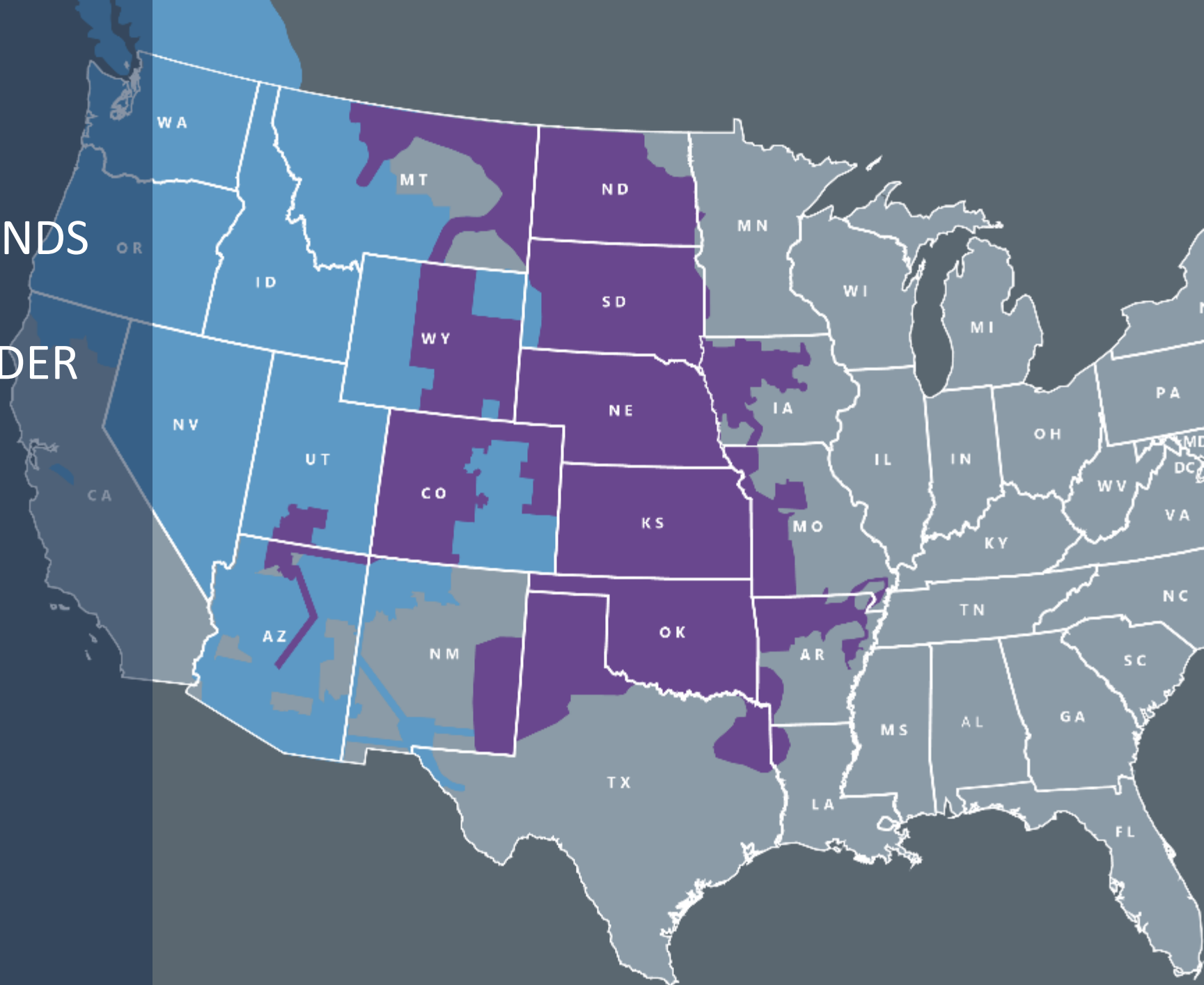
southwest-power-pool

HOT TOPICS

- LATEST STATS
- NEW GENERATION TRENDS
- LARGE LOADS
- FERC SHOW CAUSE ORDER
- NEW PROCESSES
- CPP
- 765 KV TRANSMISSION
- WE-EXPAND

 RTO

 WESTERN
ENERGY SERVICES



Latest Statistics

BALANCING ELECTRIC SUPPLY AND DEMAND

SUPPLY/GENERATION

- **110,753 MW** Nameplate Capacity (East)
(as of July 2026)

- **10,069 MW** Nameplate Capacity (West)
(as of July 2026)

- **65,639 MW** Accredited Capacity (East)
(as of Summer 2025)

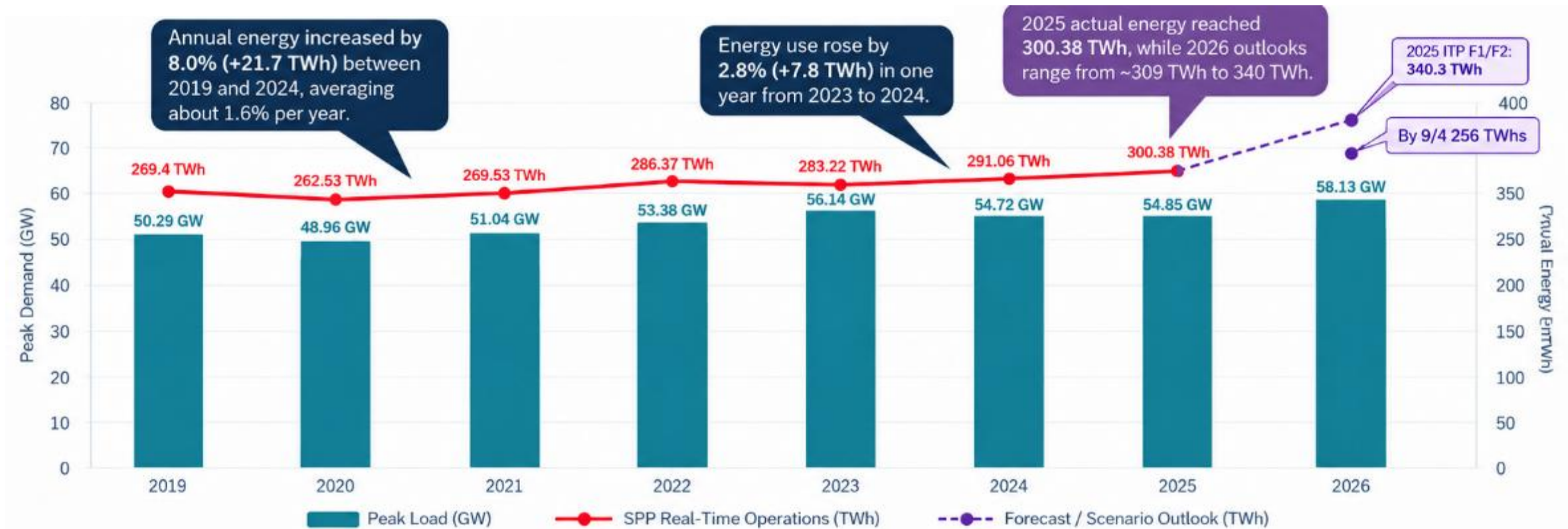
DEMAND/LOAD (East)

- **58,181 MW** all-time coincident peak load (7/27/26)

- **48,142 MW** Winter peak (2/20/25)



Regional Peak and Annual Energy Trends



Peak load grew from 50.29 GW in 2019 to 58.13 GW in 2026 (+15.6%).



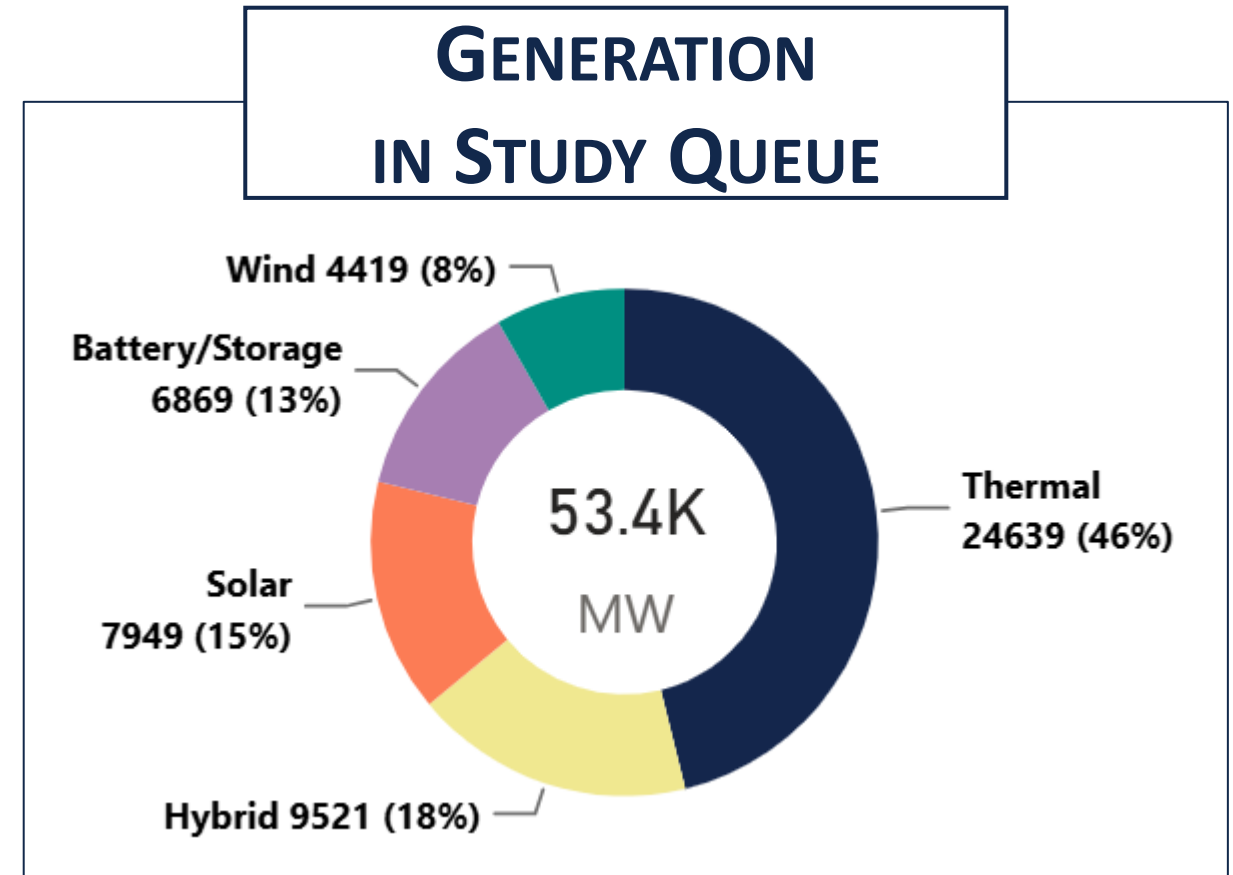
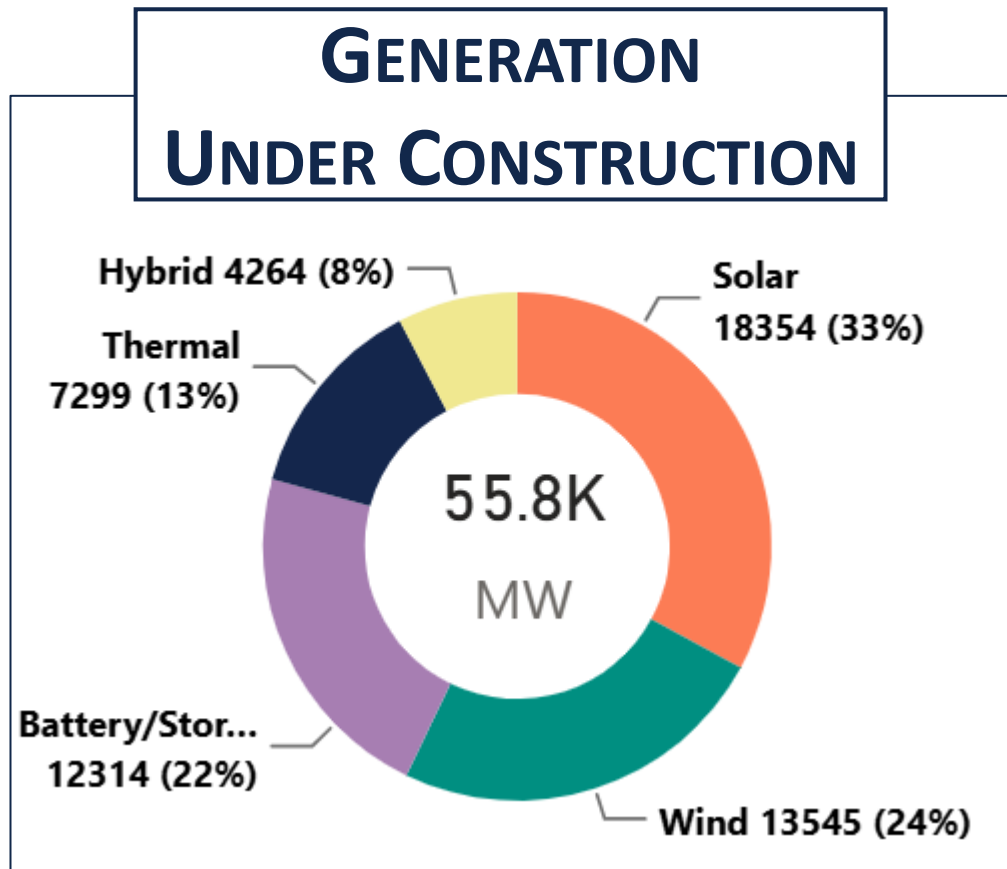
2026 peak outlook is 58.13 GW, about 6.0% above 2025.

Is load growth “for real”?

Historically, there isn't significant volumes of large loads but new records are set! 2026 peak demand is nearly 19% above 2020 and 9% above 2022, while energy use through Sept. 4 has already nearly matched the entire 2020 year.

New Generation Trends

SPP Generation Under Construction exceeds Generation in Study Queue

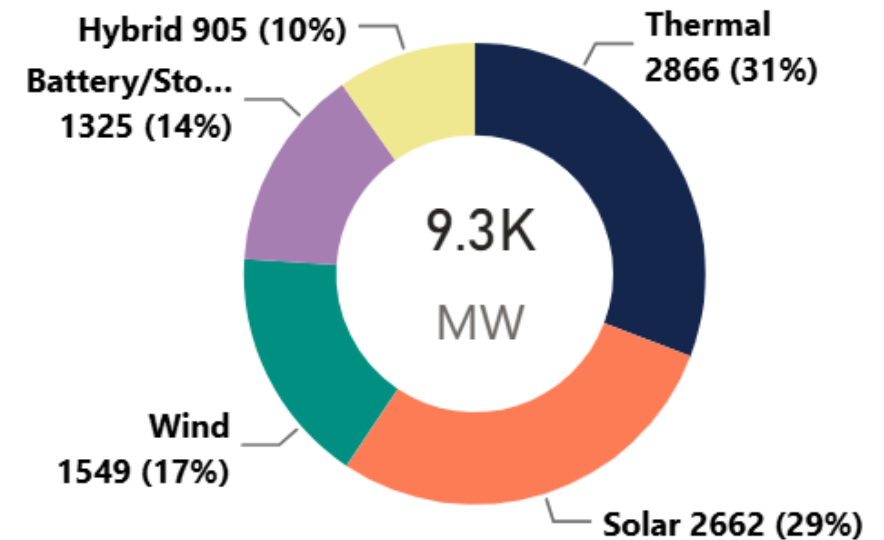
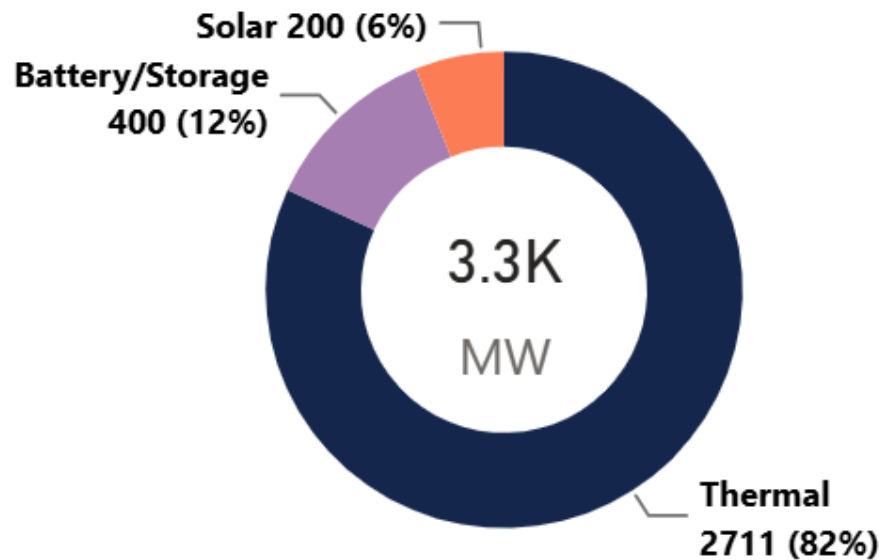
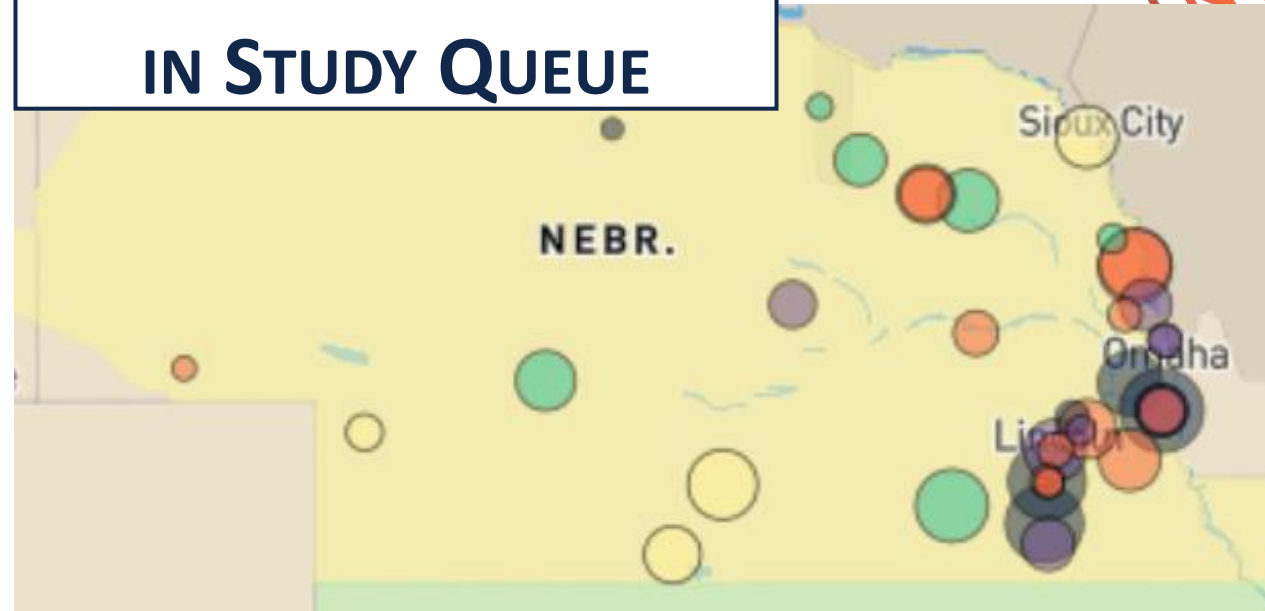


Over 150 new GIAs signed in 2026 to-date.

NEBRASKA GENERATION UNDER CONSTRUCTION

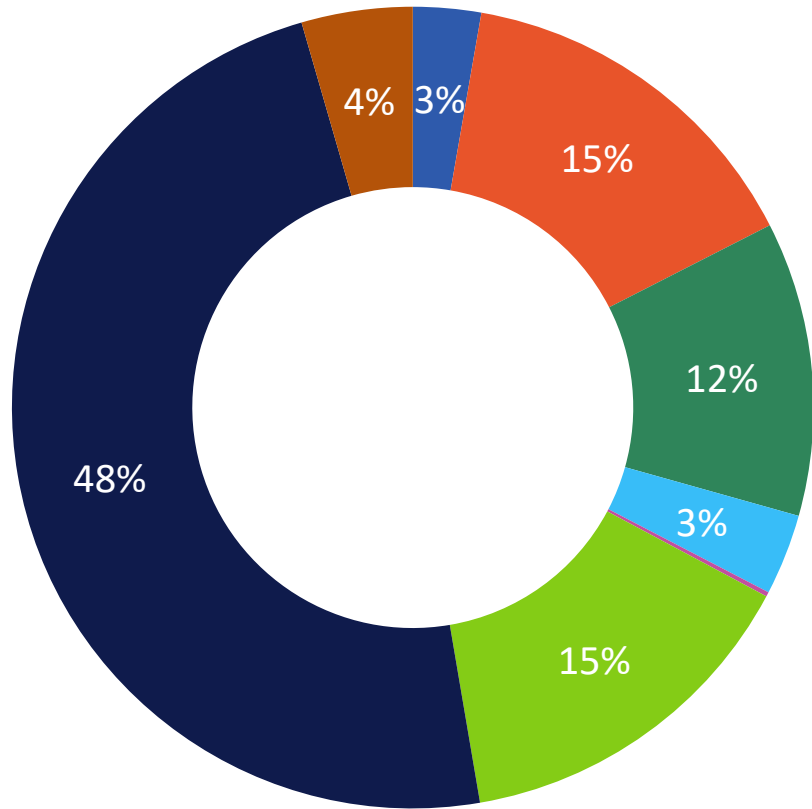


NEBRASKA GENERATION IN STUDY QUEUE



Large Load Update

SPP HILL Amounts (Active) by State



■ Colorado
■ Kansas
■ Missouri
■ Nebraska
■ New Mexico
■ North Dakota
■ Oklahoma
■ Texas

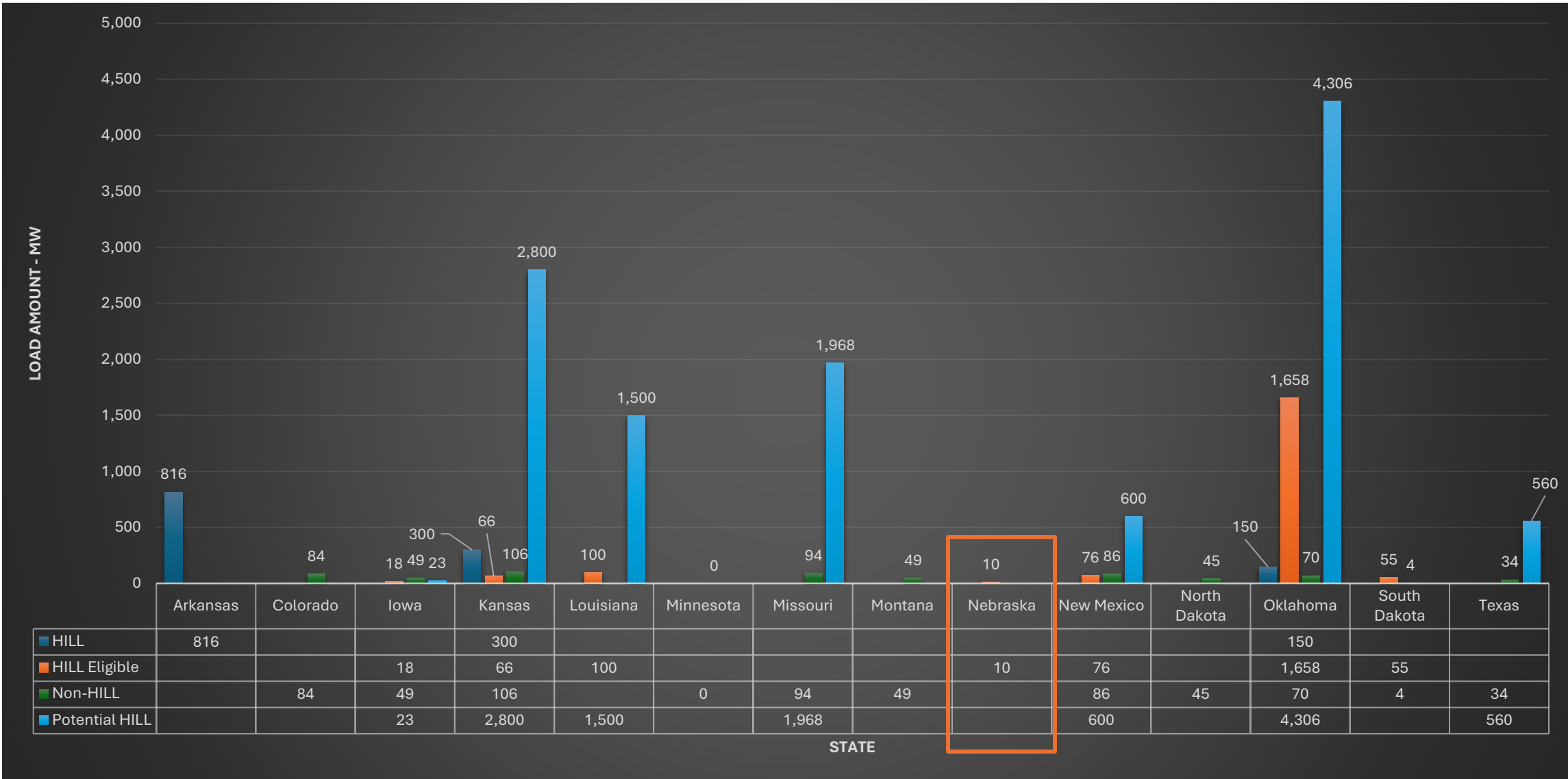
State	Requests	Load (MW)
Total	27	11,163
Colorado	2	306
Kansas	4	1,646
Missouri	6	1,325
Nebraska	2	365
New Mexico	1	20
North Dakota	1	1,620
Oklahoma	10	5,381
Texas	1	500

SPP HILL Status MW Amount by State



Requests Added to Service Agreements (MW)

* Since September 2025



FERC Show Cause Order on Large Loads

FERC Large Load Show Cause Order

FOUR CATEGORIES

The Commission ***preliminary found*** the SPP Tariff unjust, unreasonable, or unduly discriminatory in **four categories** that need to be addressed.

RR808



01

Transmission
Service to Eligible
Customer for Large
Loads

Staff led effort

CARE LEADS



02

Transparency into
Transmission Cost
& Cost Shifting Risk

RR805



03

Co-Location
Framework

Staff led effort

RR791



04

New Transmission
Services for
Flexible Large
Loads

Staff led effort

SPP Response

SPP is advancing increased transparency and robust analysis around:

- **Cost Drivers:** Clear, consistent explanation of what drives upgrade costs.
- **Alternative Technologies:** Evaluation of non-traditional solutions—storage, grid-enhancing technologies, co-location options—to meet customer needs.
- **Co-location Products:** Enabling large loads and generation/storage pairs to better utilize shared interconnection capability.

To comply with the Show Cause Order, SPP has two options:



1

SPP can seek to changes its Tariff to address the Commission's concerns

2

SPP can explain how what it already addressing the Commission's concerns

Recommendation to Address the Show Cause Order's Cost Shift Mitigation Provisions

Establish Safe Harbor for Delivery Point Costs



- The cost of Network Upgrades to add or modify load delivery points approved under the study processes of Att. AQ, AX, and BA would be Base Plan funded up to a specified limit (“Safe Harbor”)
- For each Delivery Point request, upgrade costs above the Safe Harbor, if any, would be directly assigned to the Transmission Customer
 - The current approach of 100% Base Plan funding of delivery point Network Upgrade costs would be discontinued
- Transmission Owners would be required to apply funds resulting from the direct assignment charge to reduce Base Plan Upgrade costs borne by SPP Transmission Customers

Integration of the Recommended Delivery Point Safe Harbor with Other CARE Initiatives

Compliance and Timeliness

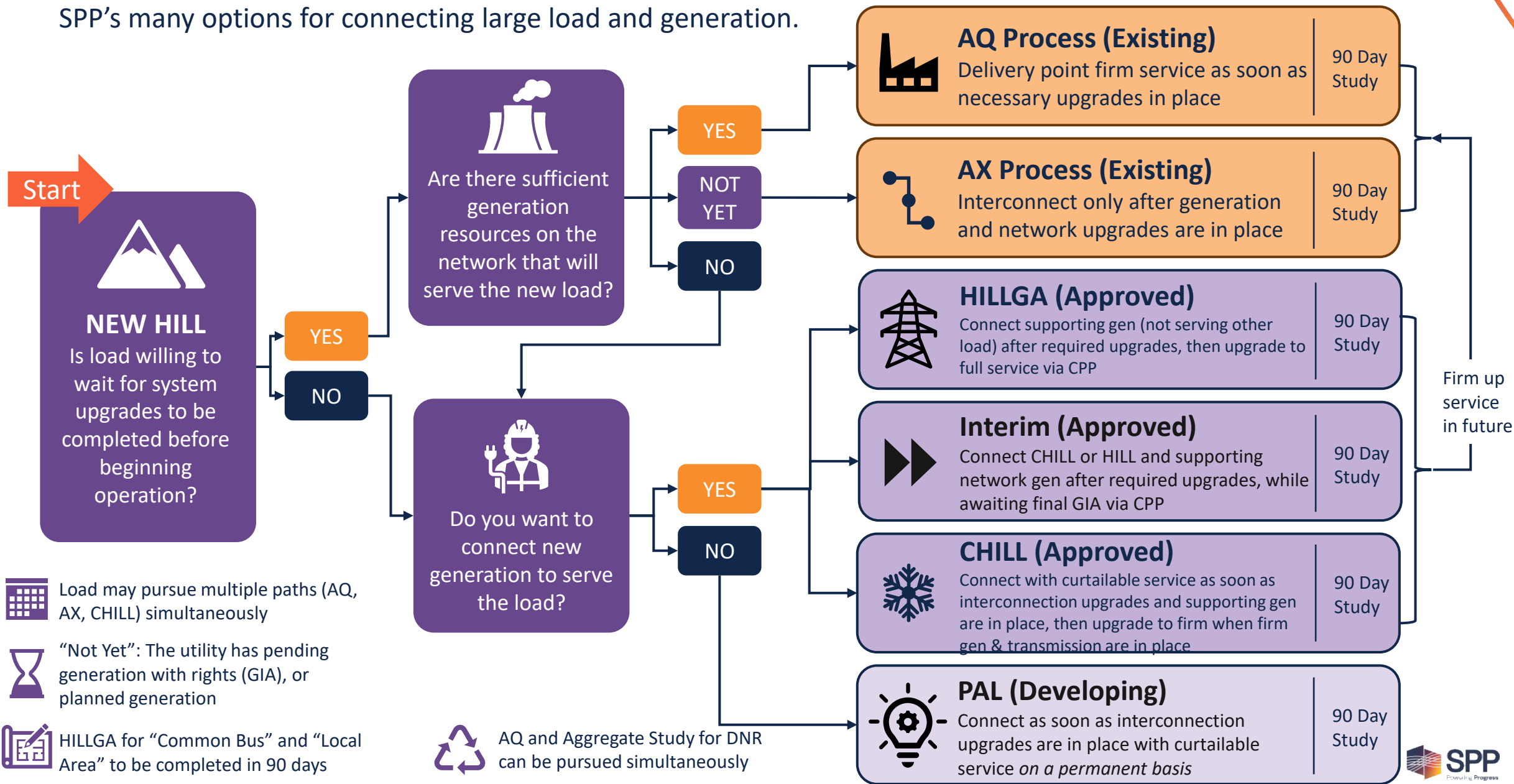


- The CARE Team's final set of recommendations is expected to move through appropriate stakeholder processes and culminate in one or more filings with FERC next year
- The Show Cause order provides an avenue for the CARE Team to support a measure that is **complementary** to its other recommendations and that may be effectuated **much sooner**
- Placing some cost responsibility for delivery point Network Upgrades on the Transmission Customer with the large load **addresses concerns in the Show Cause order** regarding cost shifts

Current & New Large Load Interconnection Processes

Connecting through Optionality

SPP's many options for connecting large load and generation.



Connectivity on a National Level Given Load Growth



69% load forecast increase from the last NERC long term assessment

Cost Control and Allocation Review & Evaluation Team CARE

CARE Scope

Transmission cost allocation and cost containment amid accelerated load growth

MANDATE

Recommend fair allocation of transmission costs and stronger cost controls while supporting reliable, cost-effective investment.

COST ALLOCATION

Who should pay?

Evaluate Highway/Byway and alternatives, with a focus on the 765 kV system. Address costs driven by large loads while limiting impacts on other customers.

COST CONTROLS

How can costs be better managed?

Assess cost drivers and improve confidence in project cost and benefit estimates. Evaluate project selection, transparency, and management of costs and schedules after authorization.

EHV OVERLAY APPLICATION

The companion policy paper focuses the cost-allocation application on facilities **above 345 kV and supporting 100–345 kV reliability facilities**. Planning determines project need; CARE addresses cost responsibility.

Cost Allocation Framework Components

1) General Allocator Modifications

Align transmission costs with system use and concentrated growth.

Energy Component

Regional and Deliverability Area

2) Load Interconnection Cost Responsibility

Att. AQ/AX/BA

Safe Harbor Limit

Direct Assignment above Safe Harbor

3) Load Materialization Protection

Protects the region if load does not materialize as planned.
(Including Spot Loads)

Forecast Protection

4) CALL Contribution

(ITP/CPP/EHV Overlay)

Alternative Cost Methodology

The framework fits together:

1) General Allocator: Establishes the cost allocation for broad system growth, including large load.

2) Load Interconnection Cost Responsibility: Establishes who pays and how much to connect the load

3) Load Materialization Protection: Preserves cost responsibility if planned load does not materialize.

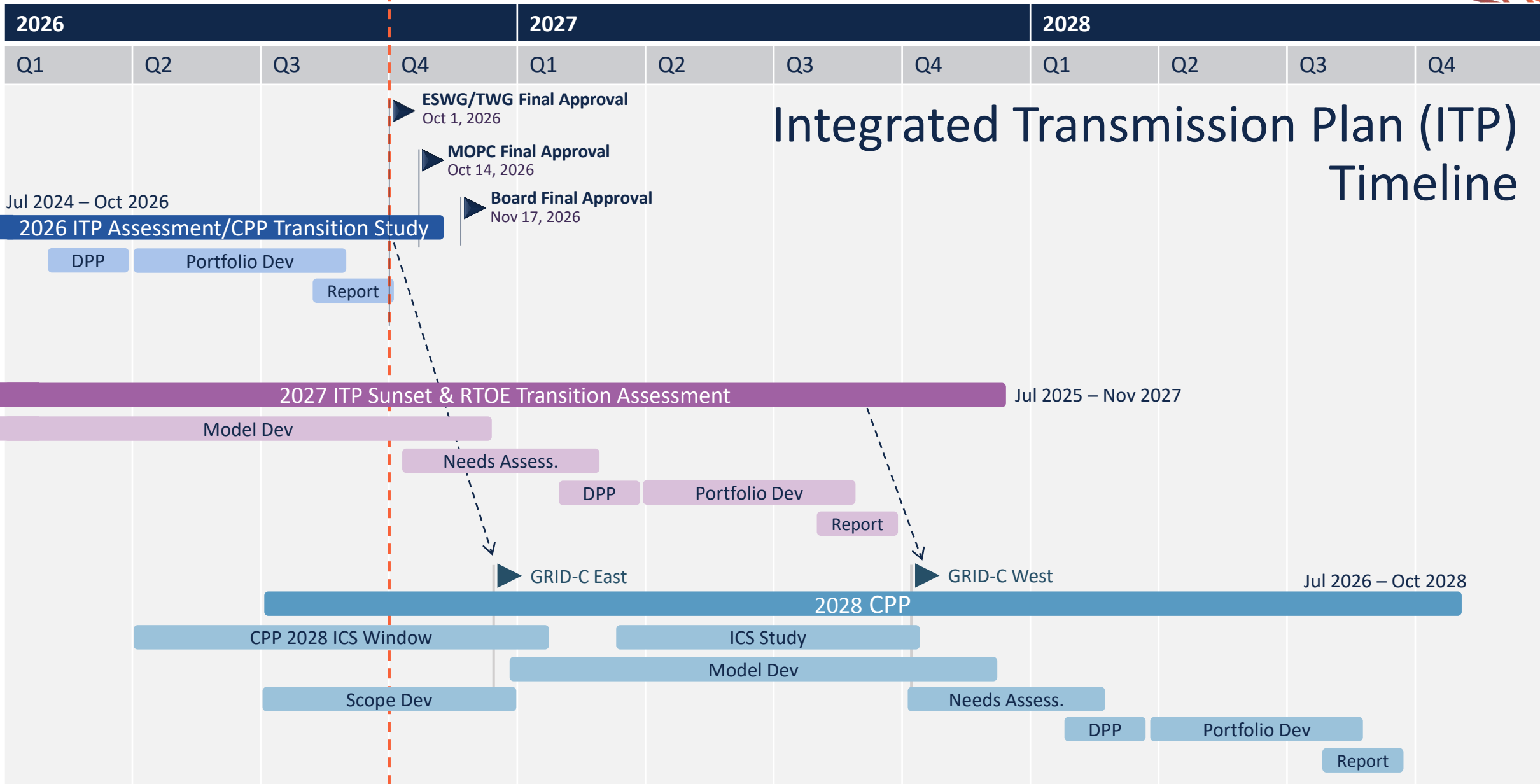
4). Large Load Charge: Addresses impacts to existing customers after allocation and protection.

CARE Team Approvals Summary | September 16-17

- **Focused Portfolio Implementation Plan** *Provide frequent, standardized reporting for EHV and other key projects, supported by expanded TRAC data and dashboards.*
- **Stranded Cost Protection Principle** *“New large loads through their transmission customer should be responsible for paying costs related to the planned new large load even if those large loads do not materialize, reduce demand or cease operations.”*
- **Cost Neutrality Principle** *“New large loads, through their transmission customer, should be responsible for incremental costs associated with service including the costs of facilities to interconnect those customers and a share of regional transmission portfolios so that existing customers are held cost-neutral* as a consequence of serving the new load.”*
- **Energy component** of at least 50% to the cost allocation methodology for facilities above 345kV and associated supporting infrastructure, and RSC consider application to other Base Plan-funded facilities.
- **Dual-limit “Safe Harbor” for Network Upgrade costs** associated with new or modified load delivery points
- **Load Materialization Risk Protection** mechanism TBD
- **Cost Allocation for Large Load Contribution** TBD

Transmission Expansion

Today Oct 1

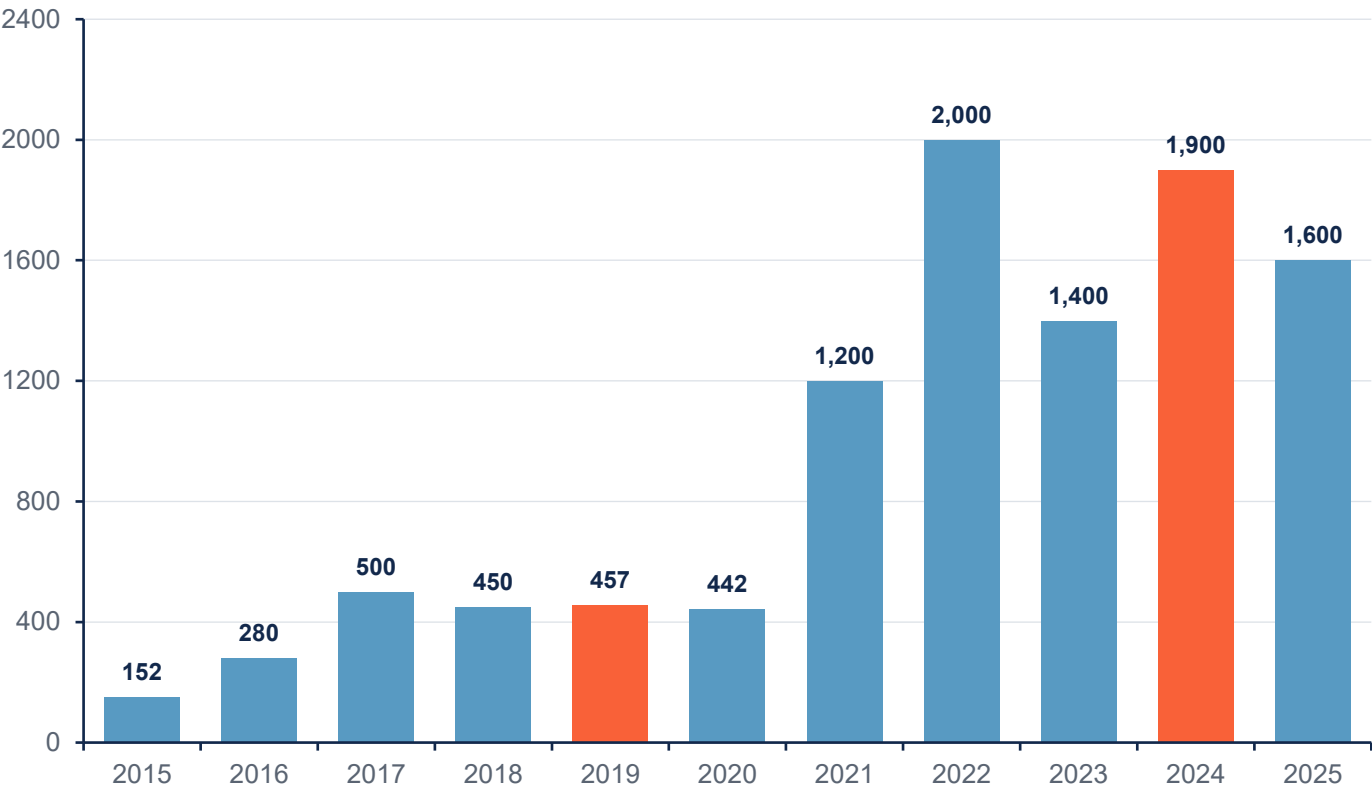


Integrated Transmission Plan (ITP) Timeline

Is the existing grid reaching its limits?

Congestion Is Growing Faster Than Load or Fuel

SPP net congestion cost, \$ millions



2019 vs. 2024: nearly identical fuel and load

NATURAL GAS (Panhandle Eastern)
\$1.93 → \$1.81 / MMBtu
– 6%

ANNUAL ENERGY
269 TWh → 291 TWh
+ 8%

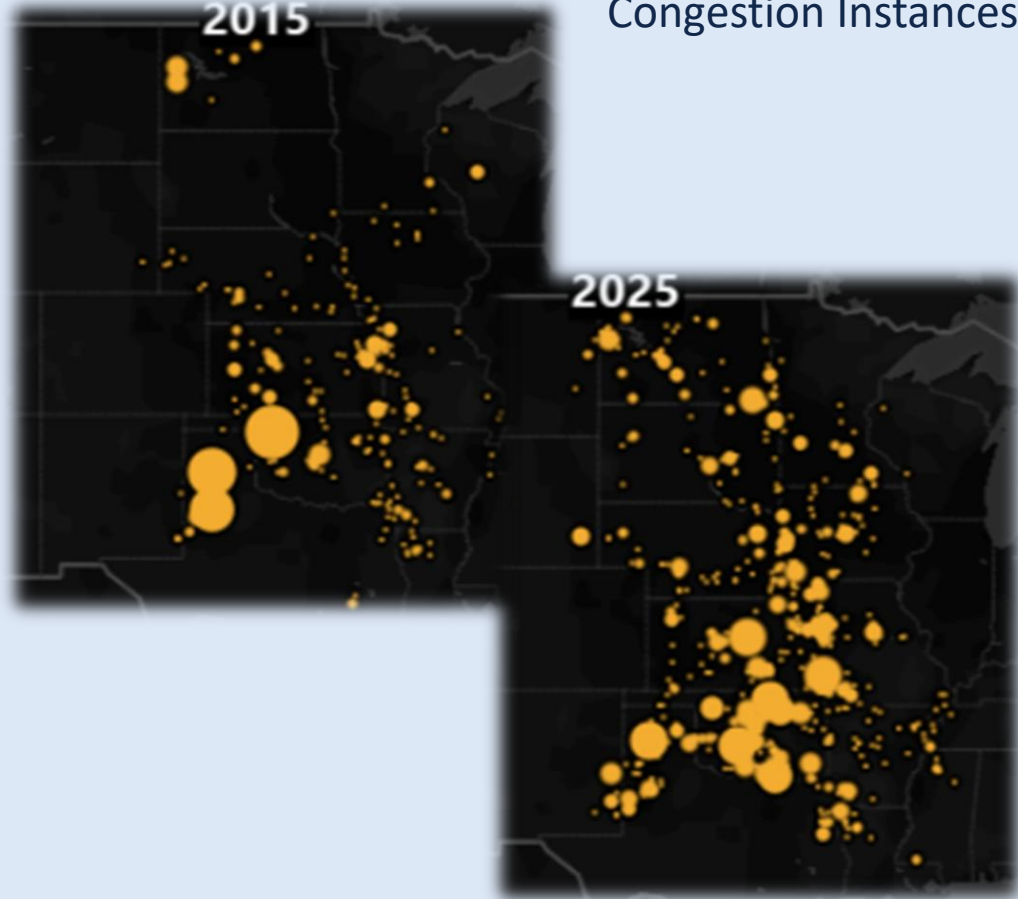
NET CONGESTION COST
\$457M → \$1.9B
+ 316%

Same fuel cost, modest historic load growth, four times the congestion.

Source: SPP Market Monitoring Unit Annual State of the Market reports, 2015–2025. Net congestion cost = day-ahead plus real-time, as reported each year. 2021–2022 reflect Winter Storm Uri and elevated gas prices; the 2019/2024 pair is used because fuel costs were comparable. 2024 shown as restated in the 2025 report.

Transmission System Stress is Increasing Already

Total Annual
Real-Time Balancing Market (RTBM)
Congestion Instances



- **Transmission emergencies are becoming more frequent**
Increased from **1** in **2022** to **16** in **2025**.
- **Congestion is occurring more often**
Constraint activity in 2025 is **~57% higher** than in 2016
- **More parts of the system are becoming constrained**
Peak distinct constraints have increased from **115** to **302** and are more **widespread on the system**.
- **Why It Matters**
 - Without additional transmission capability, SPP could see more congestion, higher market-cost exposure, reduced transfer flexibility, and greater reliability risk during stressed conditions.

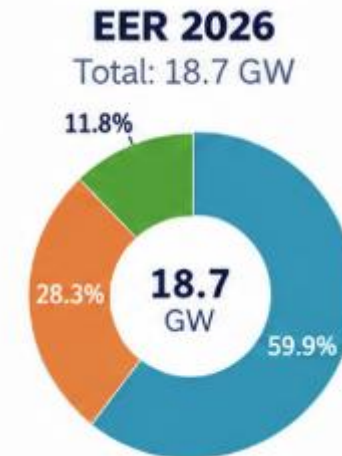
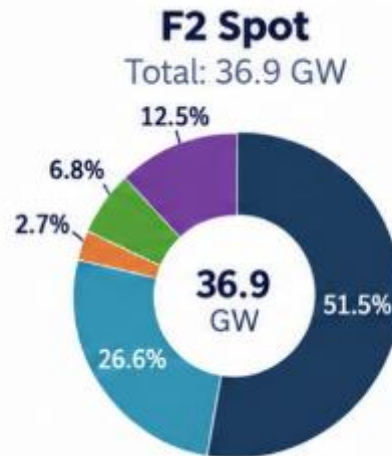
Do the ITP Spot Loads Track with Independent Forecasts?

ITP Spot Loads Total MWs are similar to independent forecasts for new large loads

Metric	Future 1	Future 2	EER 2026
Base reliability / committed firm service	19.0 GW	19.0 GW	—
Incremental spot subtotal	11.6 GW	17.9 GW	18.7 GW
Total load represented	30.6 GW	36.9 GW	18.7 GW

ITP BR Load: Base forecast for existing firm load growth that have already executed service agreements

Spot Load: Additional high confidence large-load growth added to the base that is in study or will be soon



- **Evolved Energy Research (EER) sources include and projections are future based:** Baxtel and Aterio proprietary datacenter datasets; S&P Global; Boston Consulting Group (BCG); EPRI's *Powering Intelligence 2026* analysis; McKinsey/GEP pre-publication research; Goldman Sachs 2025 datacenter power-demand outlook; and Bloomberg NEF (BNEF) / Utility Dive estimates.

2026 ITP Load Forecast Growth to 2035 (Year 10)

~60%

of 2026 ITP Future 2 spot load is correlated with actual AQ/AX requests

4.6 GW
In Agreements

5.1 GW
Study Complete

0.5 GW
In Study

2025 to 2035 Projected Load Growth



Future 1 Total = ITP BR + F1 Spot
Future 2 Total = ITP BR + F2 Spot

North				
ND, SD, NE, IA				
ITP BR (GW)	F1 Spot (GW)	F1 Total (GW)	F2 Spot (GW)	F2 Total (GW)
4.35	1.27	5.62	1.65	6.00

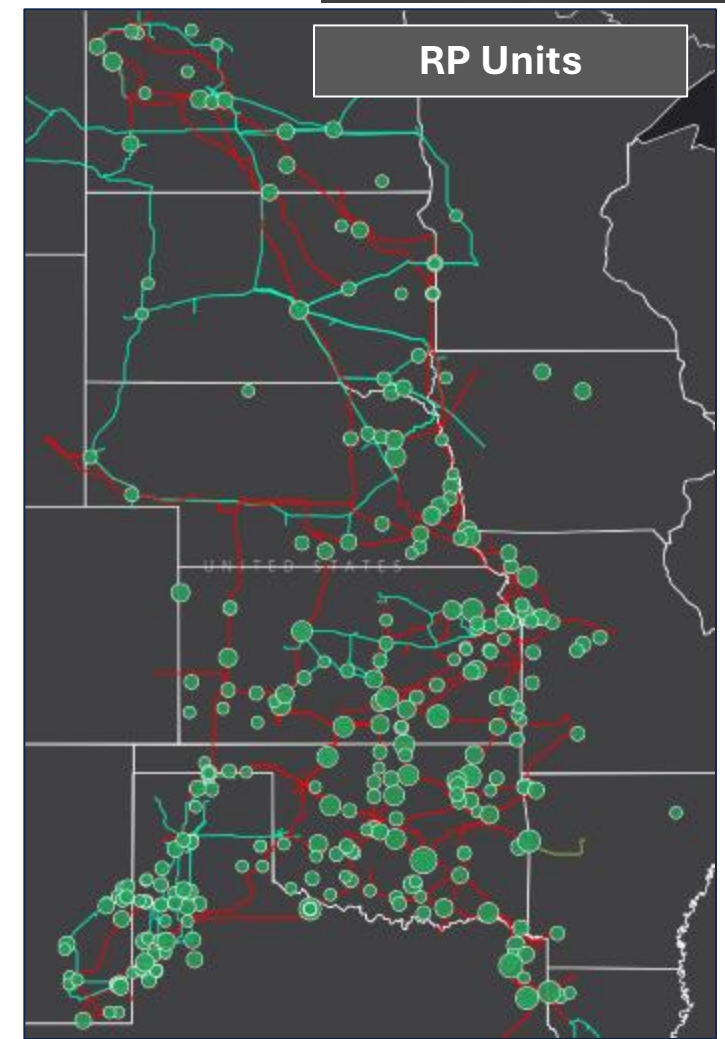
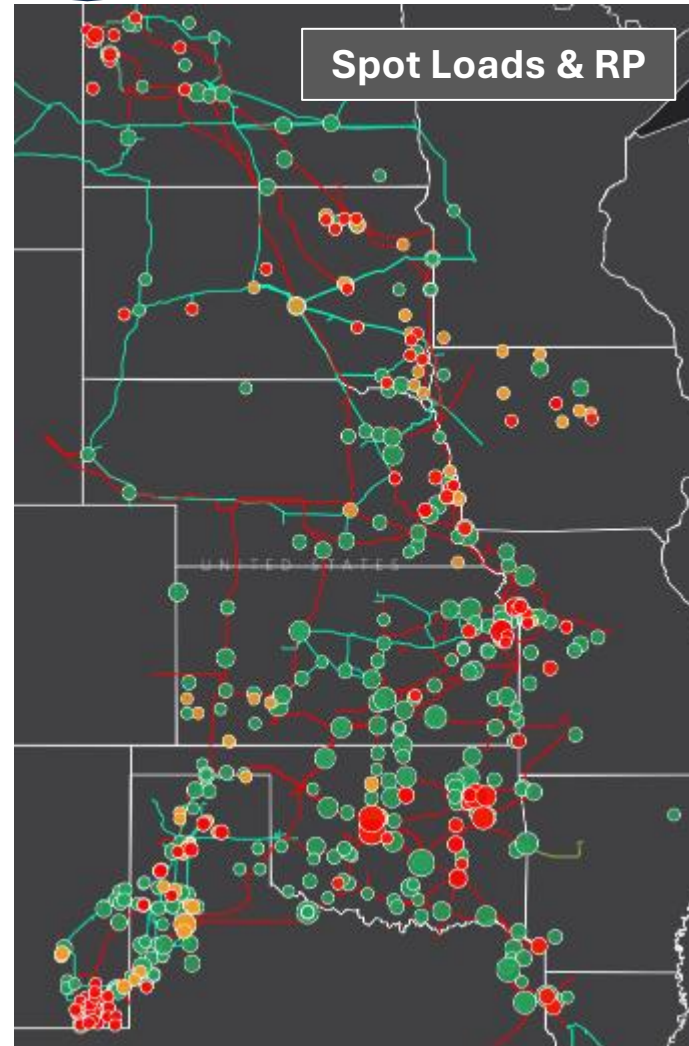
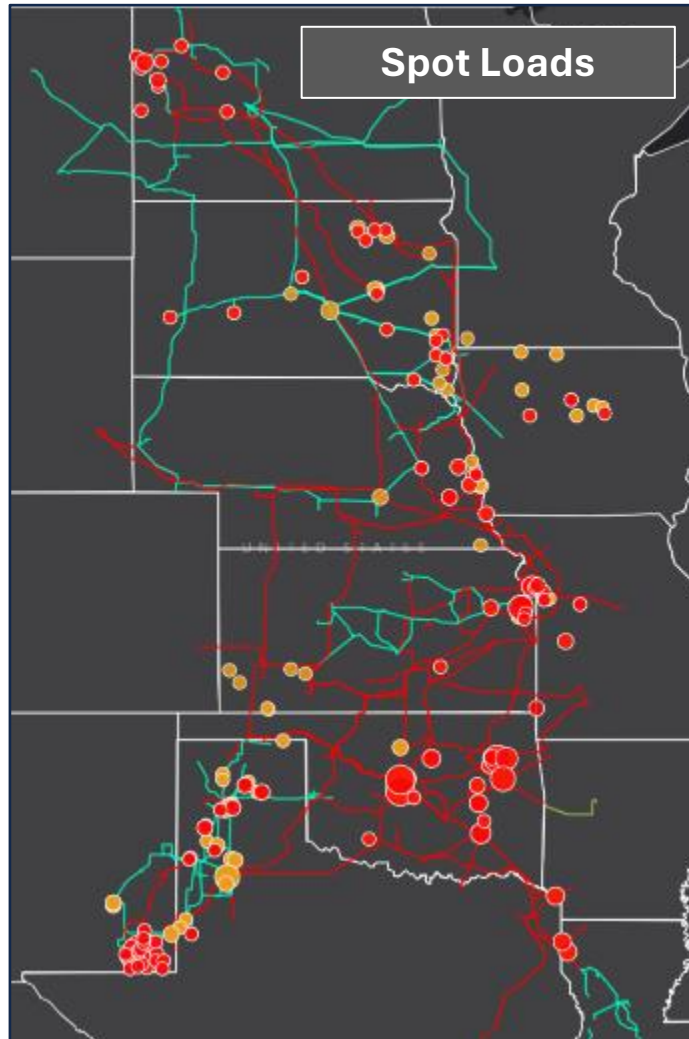
Central				
KS, MO				
ITP BR (GW)	F1 Spot (GW)	F1 Total (GW)	F2 Spot (GW)	F2 Total (GW)
4.29	4.04	8.33	4.61	8.90

South				
AR, LA, NM, OK, TX				
ITP BR (GW)	F1 Spot (GW)	F1 Total (GW)	F2 Spot (GW)	F2 Total (GW)
10.36	6.16	16.52	11.59	21.95

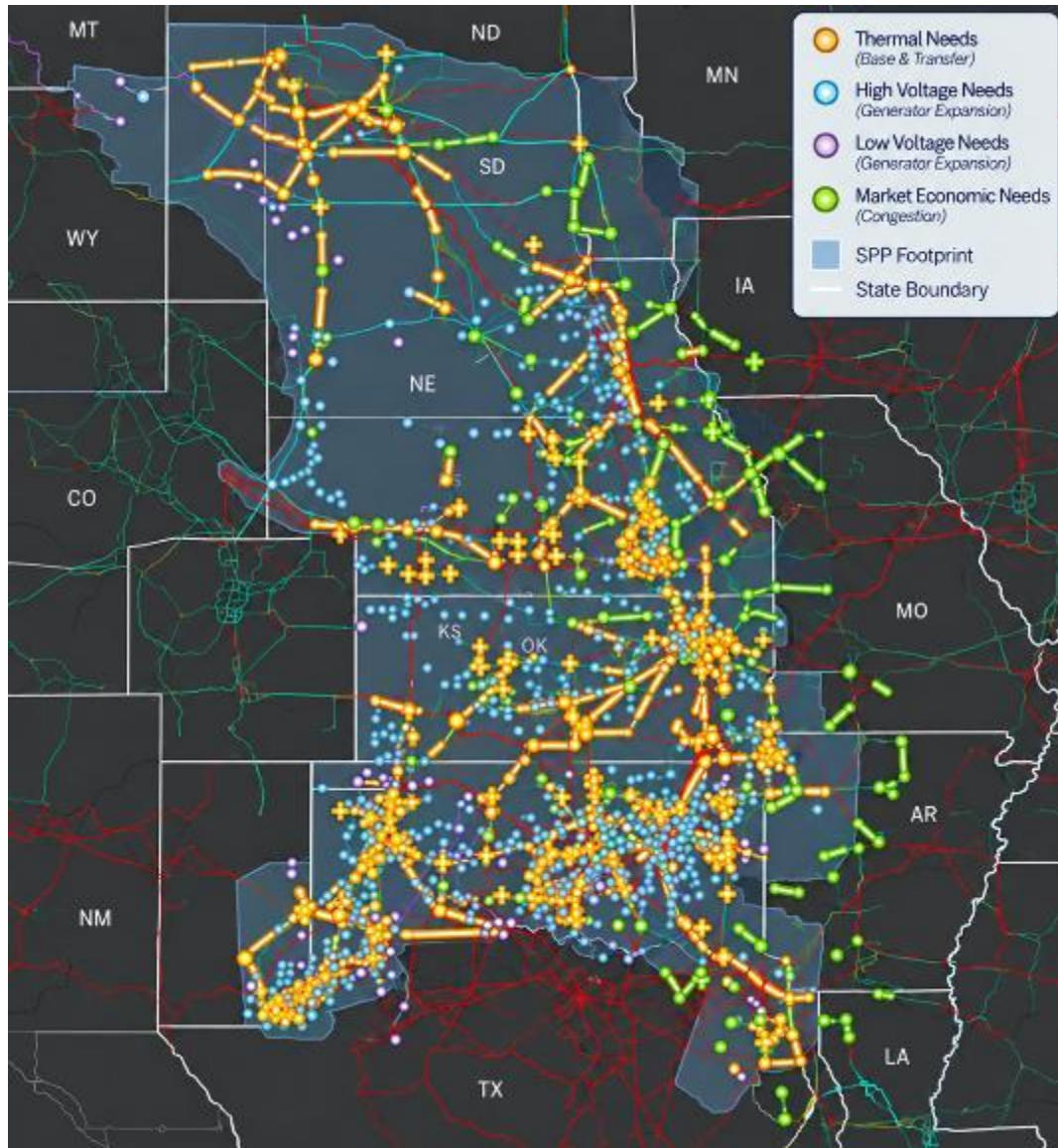
Every SPP Deliverability Area is growing when considering firm-service growth (ITP BR) + Spot Loads

Forecasted Gen and Load are Closer

The 2026 ITP generation locations are closer to existing and future load growth



2026 ITP System Needs After Planned Load and Generation

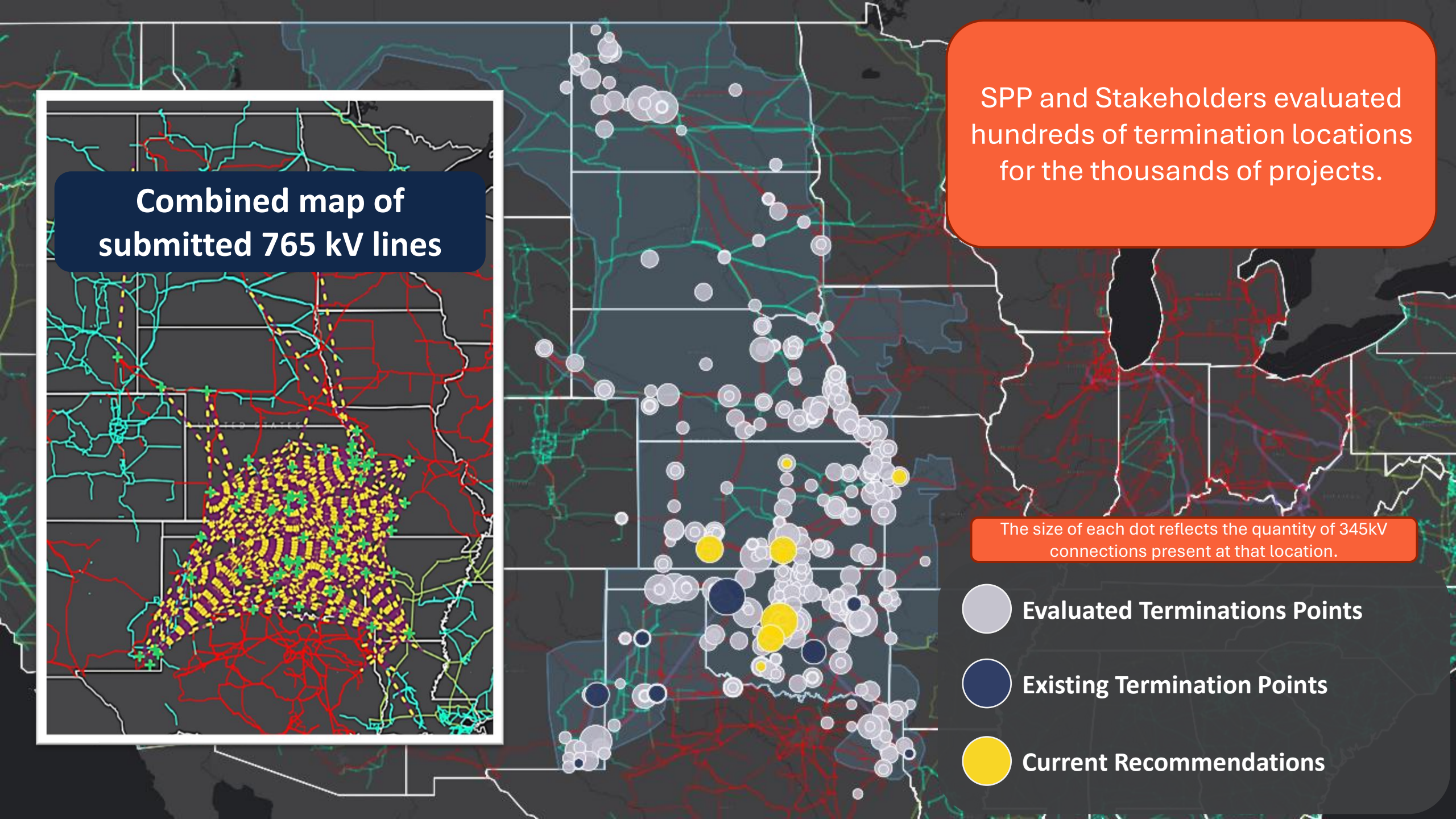


Nearly 5× more system needs identified than in any previous ITP.

Needs are broader and more complex, spanning thermal overloads, voltage issues, market constraints, generation interconnection, and load growth.

Leading to 8,200+ stakeholder provided solutions plus thousands of staff solutions evaluated.

The Portfolio Approach



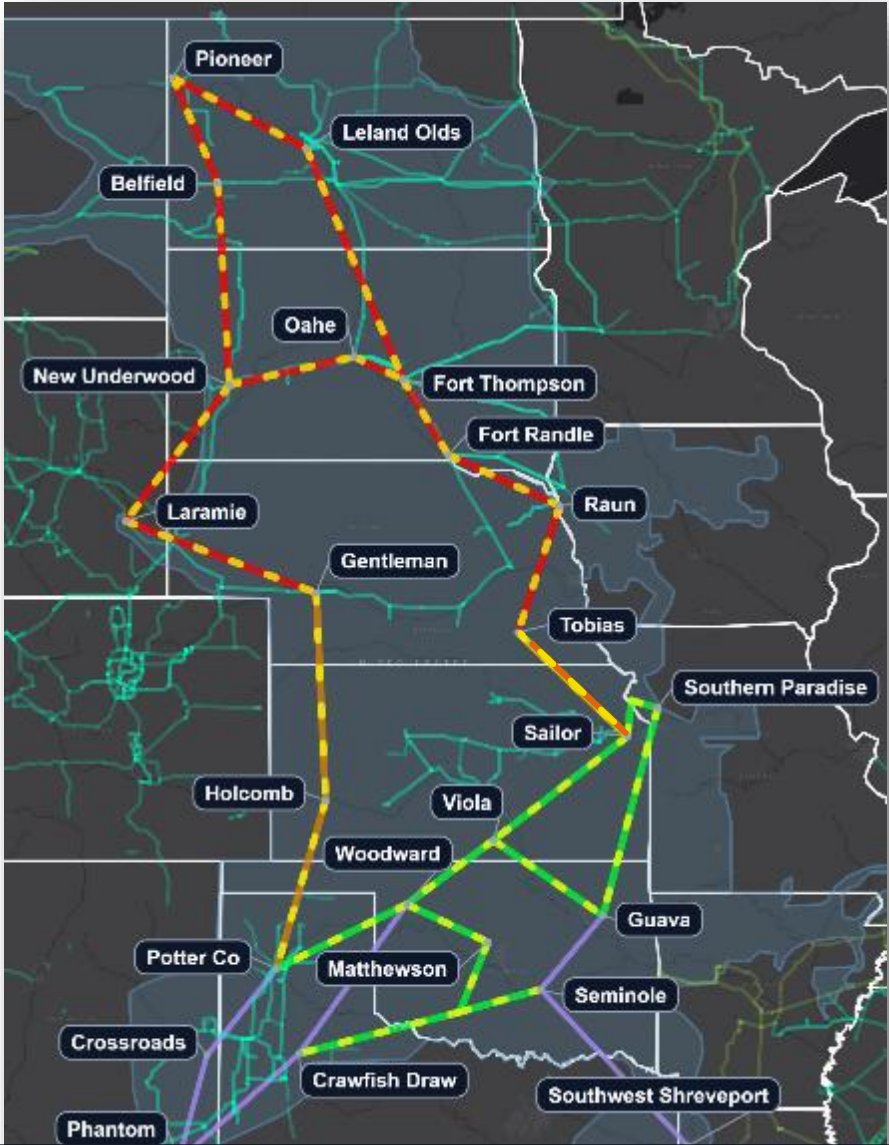
**Combined map of
submitted 765 kV lines**

SPP and Stakeholders evaluated
hundreds of termination locations
for the thousands of projects.

The size of each dot reflects the quantity of 345kV
connections present at that location.

-  **Evaluated Termination Points**
-  **Existing Termination Points**
-  **Current Recommendations**

Draft 2026 ITP and CPP Transition Study Plan

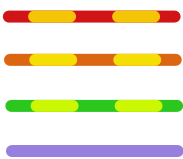


Map is for illustrative purposes only, shows general line-of-sight connectivity, and does not represent or determine final transmission routing.

Pairing the 765 kV with targeted lower-voltage upgrades significantly improves overall system performance and increases portfolio benefits.

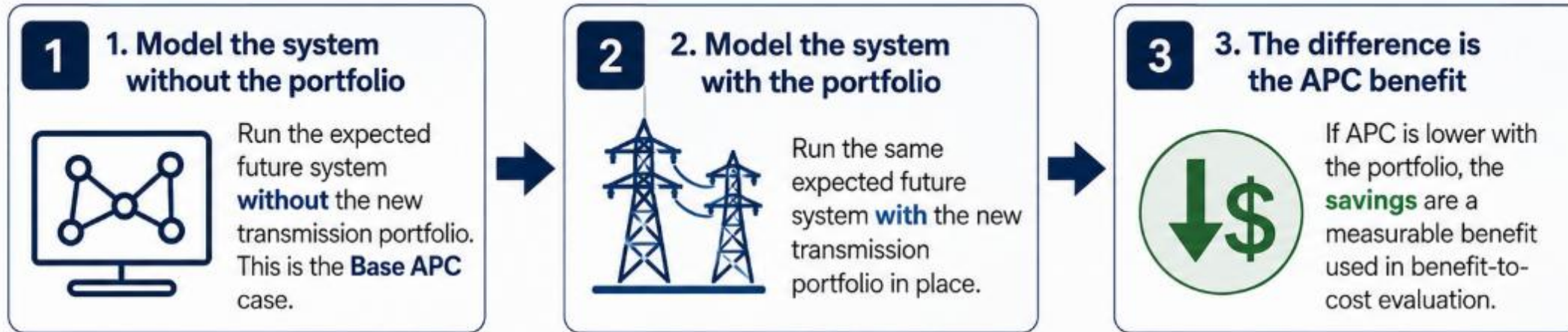
Cost basis	Cost range	Estimated benefit/cost (B/C) ratio for <u>765 kV only</u> without lower-kV upgrade (40-YR, NPV)	Estimated B/C of Study Portfolios
2026 ITP NTCs (South+Central DA's)	\$15-\$25B	Conservative B/C estimate: 2-3:1	> 20:1
2027 ITP 765 kV (Western South+Central+ North DA's, Orange lines)	Additional \$10-20B	Conservative B/C estimate: 1.5-2.5:1	> 8:1
2028+ ITP 765 kV (North DA, red lines)	Additional \$18-\$20B	Conservative B/C estimate: 1.2 – 1.6:1	> 10:1

Estimated B/C ratios and Costs of full 2026 ITP Portfolio (i.e. 20-yrs of transmission investment)



20-year overlay or sooner if load progresses earlier
Next 1-3 ITP cycles NTC candidates if load continues to grow
2026 ITP NTC candidate
2024 and 2025 ITP approved

How APC Benefits Are Measured



What APC means

APC reflects the cost to serve load. New transmission can reduce congestion, improve access to lower-cost generation, and lower overall production costs.

APC

=

Production
Cost

-

Sales
Revenue

+

Purchase
Cost

+

Native Load
Exposure



CARE takeaway: APC compares the system before and after the portfolio. Lower APC means the portfolio is creating measurable production cost savings for members and customers.

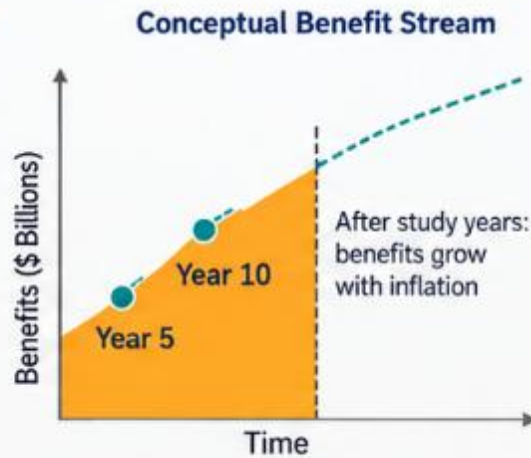
Only affiliated generation is captured in APC calculation to justify transmission

APC Results Are a Conservative Floor of 40-year Benefits

Current modeling assumptions understate the true value of the EHV overlay.

How the 40-year benefit is calculated

-  **Model a few benefit years**
(e.g., Year 5 and Year 10)
-  **Interpolate**
between modeled years
-  **Apply inflation-based terminal value**
after study years
-  **Discount all benefits**
to present dollars
(40-year NPV)



Discounted to
Present Value (NPV)

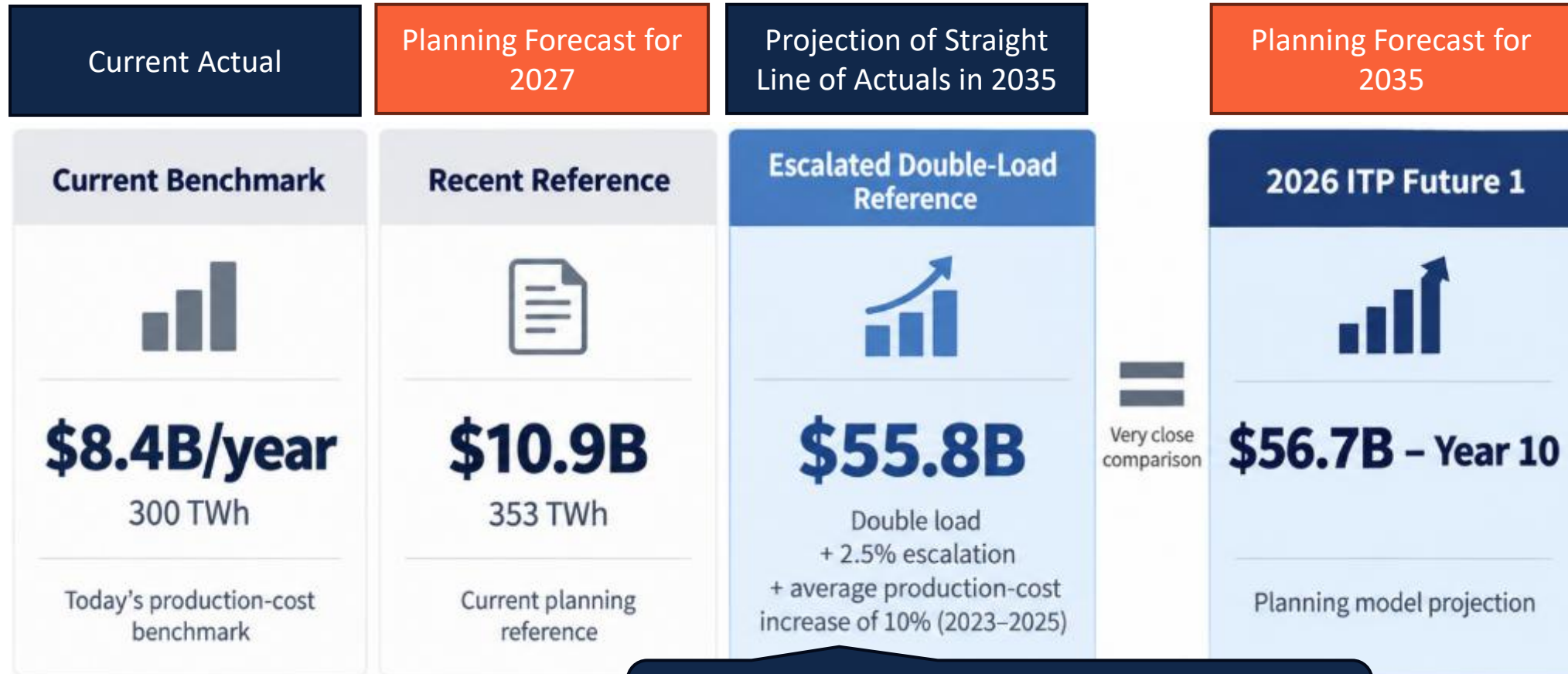
Why APC may understate total value

-  **Reliability requirements do not fully translate to APC**
Some reliability benefits (e.g., load shed reduction, resiliency) are not monetized in APC.
-  **Non-affiliated generation ("SPP Other") is excluded**
Benefits from non-affiliated generation are not included in APC.
-  **Transmission outages are not modeled at all**
The dispatch only accounts for N-1, but the outage is never applied.
-  **Generation outages are modeled at lower than actual levels**
Generation outages in the models are below real-world levels.
-  **Load forecast is only 50/50 and does not account for volatility**
The load forecast does not include any volatility or forecast errors.
-  **Renewable forecasts have no volatility or forecast errors**
Similar to load, renewable forecasts are deterministic with no volatility or errors included.



CARE takeaway: APC should be viewed as the lower-bound economic value of the EHV overlay — not the full benefit case.

Comparing Production Costs Actuals Vs Projects



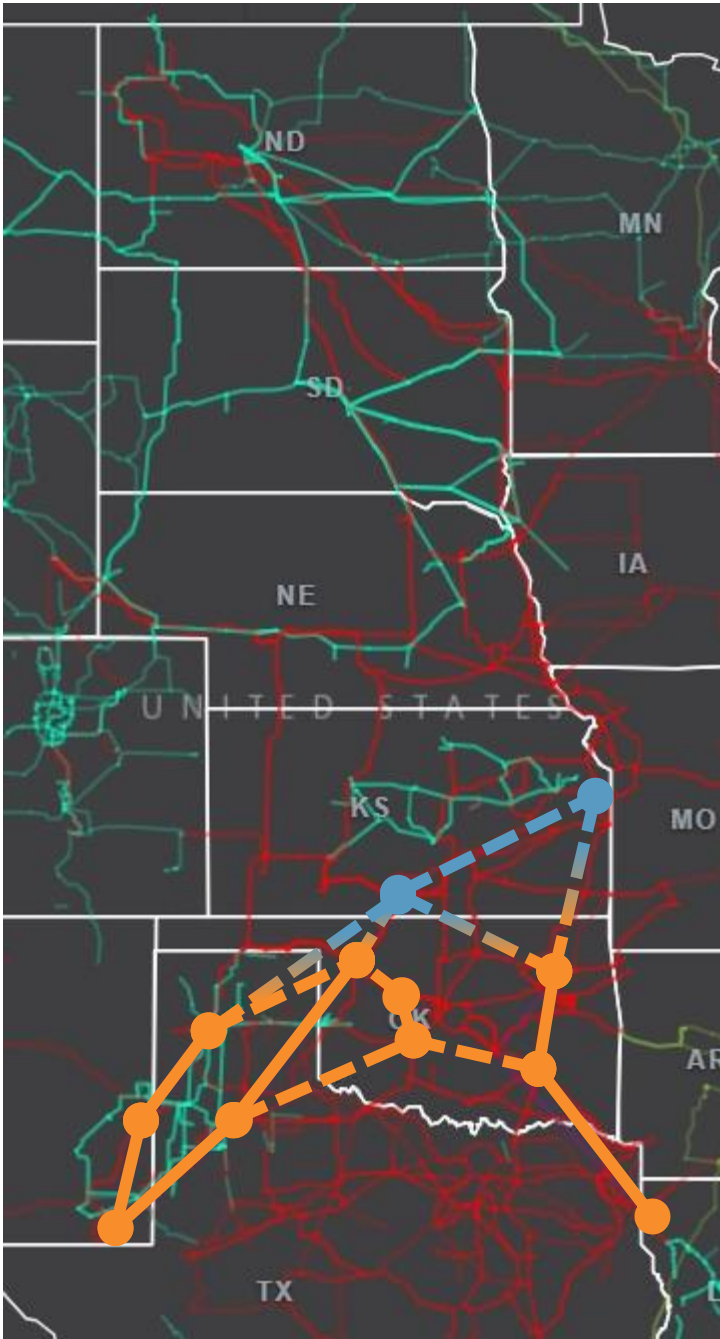
Conservative assumption: transmission constraints do not increase prices beyond recent production cost increases while doubling load



What are APC savings?

APC savings are the transmission-driven reductions from projected base production costs. In simple terms: transmission lowers the future cost to operate the grid.

Today's market cost is an actual benchmark. Future 1 and Future 2 are projected Year 10 production costs. The straight-line reference is illustrative only and assumes today's average base production cost (~\$28/MWh) scales with energy.



Draft 2026 ITP NTC Benefits by DA

- Economic Portfolio currently estimates a regional B/C ratio between **27.5:1 to 55.9:1 (F1/F2)**
 - All zones have positive benefits by Year 10 in both futures
- Benefits are calculated for each deliverability area below
 - 40-year benefits for Future 2 are more than **\$1 trillion**
 - 40-year costs of economic projects between \$24.5-25.1B

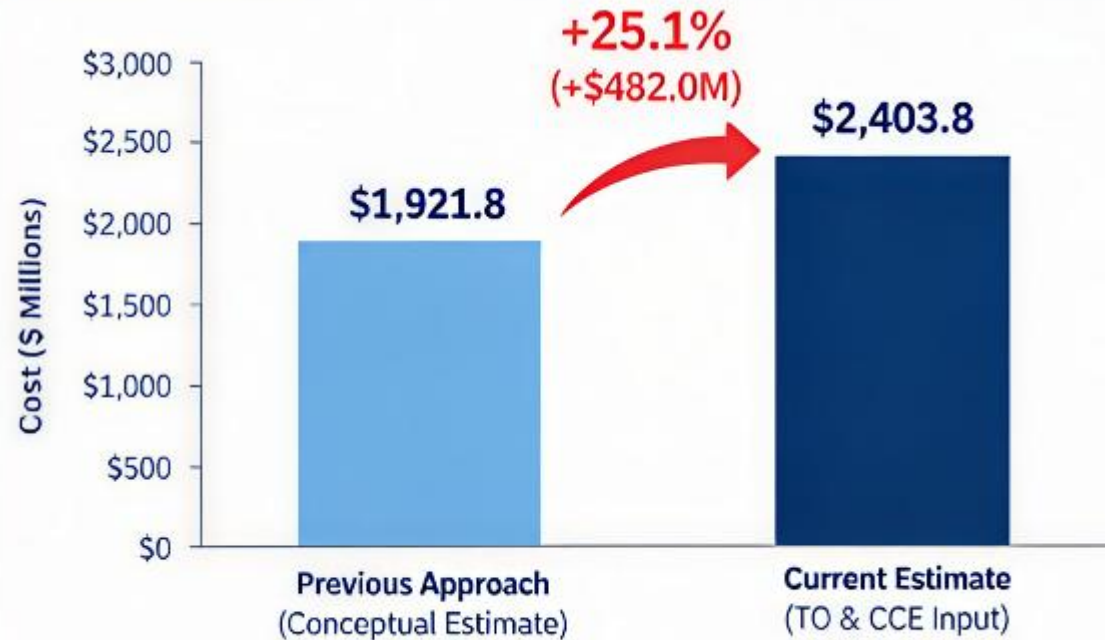
	F1 Y5 (\$M)	F1 Y10 (\$M)	F1 40-Yr (\$M)	F2 Y5 (\$B)	F2 Y10 (\$B)	F2 40-Yr. (\$B)
North	\$121.6	\$3,938.4	\$80,081.3	\$0.6	\$7.1	\$143.2
Central	\$557.3	\$4,498.6	\$89,377.2	\$0.6	\$4.6	\$91.9
South	\$2,068.9	\$25,129.4	\$504,491.4	\$16.7	\$61.4	\$1,174.8
Total	\$2,747.7	\$33,566.5	\$673,950.0	\$17.9	\$73.2	\$1,410.0

Note: As the economic projects are consolidated with other projects, these numbers will change and likely be reduced

SPP's 765 kV Cost Estimates Are More Accurate and Project-Specific

Current estimates incorporate detailed transmission owner and CCE input that better reflects the full project scope, resulting in a more reliable and defensible cost estimate.

Total Project Cost – Elm Creek to Viola 765 kV



What's Improved in the Current Estimate?



More detailed scope

Includes full line, substations, reactors, transformers, terminal equipment, and 345 kV interconnection work.



Incorporates TO and CCE input

Uses detailed, project-specific cost information from transmission owners and consolidated planning models.



Captures additional equipment and scope

Includes substation work, transformers, and rebuilds that were not fully reflected in the conceptual estimate.



Greater accuracy and confidence

Provides a more reliable basis for planning decisions and benefit evaluation.



Key Takeaway: SPP's 765 kV cost estimates increased **25.1%** as the estimate evolved from conceptual assumptions to a detailed, project-specific cost basis, resulting in a more accurate and reliable estimate.

WE-EXPAND

Western - Eastern Expansion of eXchange
Pathways and Network Development

Strategic Context: Today's Limits

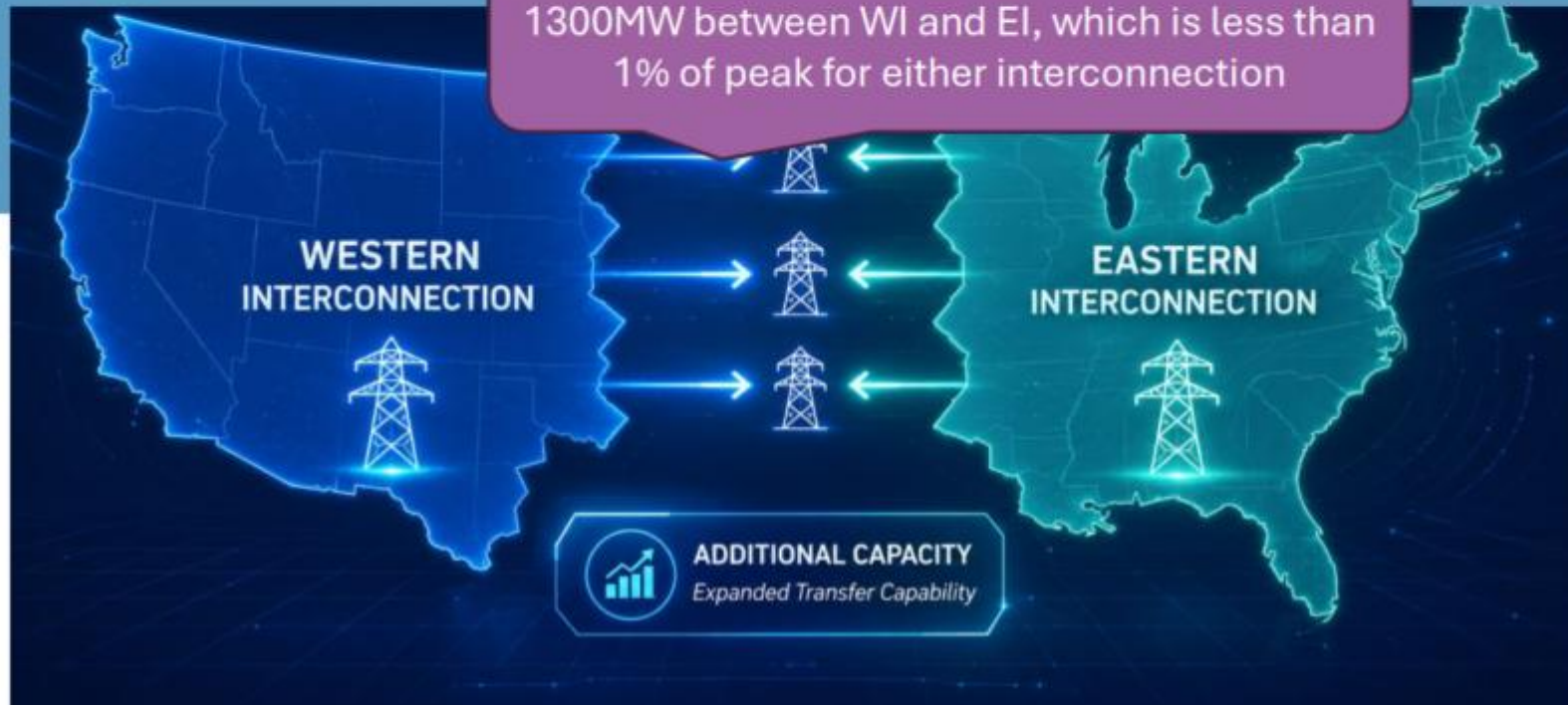
Regional growth

- Rapid load, resource additions, reliability needs, and changing flows are increasing the value of flexible transfer capability.
- Imports/exports are critical to historical extreme events and situations

NERC's 2025 Long-Term Reliability Assessment

- Summer peak demand across all interconnections is projected to grow 18–20% over the next decade

Currently there is a max transfer amount 1300MW between WI and EI, which is less than 1% of peak for either interconnection



Strategic Context: Alignment with Strategic Plan

Strategic Imperatives: *The priorities that will define our future*

High Priority study directly aligns with two of the new Strategic Plan's strategic imperatives

- Increasing reliability, resiliency, and market efficiency due to greater resource sharing between interconnections
- Greater seams opportunities and potential connectivity with SPP Western Services



Potential Key Benefits

Lower Costs and Investment Needs

Improves energy transfers, reduces production costs, and may defer future resource investments.

Greater Reliability and Resilience

Expands access to available resources and reserves while providing more options during stressed or changing system conditions.

More Efficient Use of Regional Resources

Improves coordination and utilization of existing resources across regions.

Informed Cost Allocation Decisions

Provides a technical basis for the RSC to evaluate and support future cost allocation decisions.

Resource Impacts & Next Steps

8/4/26

- Request approval to begin scoping High Priority study at 8/4 BOD meeting

Q3-4 2026

- Work with TWG/ESWG to develop study scope

Calendar year 2027

- Q1 MOPC Scope Approval
- Execute study

Q4 2027/Q1 2028

- Present final results, including recommendations for construction

High-priority studies require clear identification of resource impacts. This study represents a \$1.2 million operating plan investment, with anticipated benefits expected to demonstrate value that significantly exceeds the study cost.

Takeaways

- Load growth is accelerating.
- SPP's generation backlog has been eliminated, but challenges remain.
- SPP's has developed new, faster ways to evaluate the impact of large loads & generation.
- SPP continues to innovate ways to speed decision-making to facilitate connection of loads and the resources needed to serve them.
- Reliability remains top priority with economics and affordability close behind.
- 765 kV build-out happening in stages, with check-and-adjust as load and resource needs change.
- SPP continues to refine processes for cost estimation and cost allocation to adjust to changing landscape and stakeholder concerns.
- SPP is actively looking for ways to maximize the value of the east-west system and market.



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