Exhibit No.:	
Issue(s):	*Large Load Customer Service Tariff*
Witness:	*J Luebbert*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case No.:	*ER-2024-0261*
Date Testimony Prepared:	*July 21, 2025*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

DIRECT TESTIMONY

OF

J LUEBBERT

THE EMPIRE DISTRICT ELECTRIC COMPANY, d/b/a Liberty

CASE NO. ER-2024-0261

Jefferson City, Missouri
July 2025

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DIRECT TESTIMONY

OF

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THE EMPIRE DISTRICT ELECTRIC COMPANY,
d/b/a Liberty

CASE NO. ER-2024-0261

Q. Please state your name and business address.

A. My name is J Luebbert and I am employed by the Missouri Public Service Commission as the Manager of the Tariff/Rate Design Department of the Commission Staff. My business address is 200 Madison Street, Jefferson City, Missouri 65102. A list of cases that I have participated in before the Commission are attached as Schedule JL-d1.

Q. What is the purpose of your direct testimony in this case?

A. My testimony will provide additional information and support of Staff's recommended Large Load Customer Service ("LLCS") tariff recommendations. Generally, I will describe added costs through Empire's participation in the Southwest Power Pool ("SPP") that may be incurred if large load customers are added to Empire's system and provide proposed solutions to those issues.

Q. Are there other Staff witnesses that address LLCS recommendations?

A. Yes, my testimony can effectively be viewed as a supplement to the proposal that is more thoroughly described in the Direct testimony of Staff witness Sarah L.K. Lange.

Q. How is your testimony organized?

A. My testimony is broken into the following sections of SPP costs:

1. Energy related costs
    a. Load and Generation imbalances

b. Day-ahead and Real-time imbalances

c. Recommended solution to energy imbalances

d. Ancillary services

e. SPP Protocols for Non-Conforming load

f. Conclusion on SPP costs related to energy

2. Demand related costs

a. Penalties for Resource Adequacy shortfall Recommended rates

i. Demand Deviation Charge

ii. Imbalance Charge

ENERGY RELATED COSTS

Q. Generally, how does Empire's participation in SPP result in costs to ratepayers?

A. Empire purchases all energy necessary to serve load from the SPP integrated market in each interval of time throughout the year based upon the locational marginal price ("LMP").[1] Empire participates in both Day-Ahead (sometimes referred to as Day 1 market) Market and Real-Time Balancing Market (sometimes referred to as Day 2 market). Similar to the purchase of energy to serve load, Empire bids all of its generating units into these markets and the generating units are dispatched by SPP's Security Constrained Economic Dispatch model based upon the LMP at the settlement location of each generator. Revenues from generating units are based upon the SPP dispatch instructions and the LMP at the time of generation.[2]

[1] Locational Marginal Prices are made up of three components: Marginal Energy Cost, Marginal Loss Component, and Marginal Congestion Component.
[2] The costs and revenues are reflected in Empire's rates as well as Fuel Adjustment Clause rates.

Load and Generation imbalances

Q. How could additional costs arise from the differences in LMP at generation pricing nodes and Empires load pricing node?

A. Additional cost and revenue imbalances may also occur if Empire adds specific generation resources in order to serve LLCS customers. Since LMPs vary by location and by time, the energy utilized by the LLCS customer may cost more than the revenue received from energy generated during the same time period at a different location. Furthermore, if the types of generation added are not dispatchable, additional cost and revenue imbalances may exist between the timing of energy usage and energy production. To the extent that these imbalances exist in the future and add to the cost to serve load or reduce off-system sales revenues, non-LLCS customers would realize additional costs through the Fuel Adjustment Clause ("FAC"). Each generation station currently owned by Empire has its own commercial pricing node. As noted in the section below, Staff recommends separate commercial pricing nodes for each of the LLCS customers served by Empire.

Day-ahead and Real-time imbalances

Q. How could additional costs arise from differences between Empire's bids for load purchases for LLCS customers in the Day-ahead and Real-time markets?

A. Changes to actual operational loads of LLCS customers compared to expected loads that are not reflected in Empire's respective bids for load purchases from SPP can cause imbalances in the overall purchased power costs that will flow through the FAC if these costs are not identified and isolated. The expected LLCS customers' relative loads is important to consider because the load of these customers is would be the largest on Empire's system, and will dramatically impact the overall purchased power costs of Empire through SPP.

Q. Can these costs be precisely quantified at this time?

A. No. The exact dollar impact cannot be determined at this time because the imbalance will be determined on an hour by hour basis, comparing the cleared Day-ahead and real-time costs, as well as projected load, compared to actual real-time load.

Absent active identification, mitigation, isolation non-LLCS ratepayers may end up subsidizing these costs. Given the impact that the LLCS load will have on Empire's SPP purchased power expense and capacity requirements, Empire should obtain and understand the LLCS customers' operational requirements on a daily basis to be incorporated into the day-ahead bids. As discussed in Ms. Lange's direct testimony, Staff recommends these rates be set at initial rates of $0.002 $/kWh for the summer billing season, and $0.001 $/kWh for all non-summer billing seasons. If a separate load node is established for each LLCS customer as Staff recommends, these rates should be based on the collective net deviation expense of the LLCS class across all LLCS load nodes.

Q. Have these costs been explicitly recognized in other cases before the Commission?

A. Yes. Specifically, in the Stipulation and Agreement in Case Number EO-2019-0244,[3] relating to Evergy Missouri West's ("EMW") cost of serving a customer on

[3] The non-unanimous stipulation and agreement in Case No. EO-2019-0244 paragraph 7.d. states: GMO will monitor Nucor operations and will identify additional SPP related costs resulting from unexpected operational events. If actual Nucor load experiences a 25% deviation from the expected Nucor load for more than four (4) hours and that load change is not reflected in the GMO day-ahead commitments, GMO will quantify the balancing relationship between the hourly and day-ahead prices to identify the effect of the unplanned load change to apportion any additional SPP balancing charges and will incorporate the effect attributed to Nucor into the tracking of Nucor costs. If the effect of this relationship increases costs to non-Nucor customers, the amount will be reflected in a subsequent FAC rate change filing and the portion attributed to Nucor will be identified with supporting work papers and removed from the Actual Net Energy Cost prior to the calculation of the FAC rates. For any incremental Nucor costs not specifically listed in Exhibit 1, including GMO internal costs attributable to Nucor, the costs will be uniquely recorded after they are incurred consistent with the cause of the cost and identified as contingency cost category within Exhibit 1.

Schedule SIL.[4] The stipulation and agreement in the EO-2019-0244 case required EMW to monitor and isolate costs related to changes in operation from expectation, but this requires additional tracking of information and has been raised as an issue in several cases since the original stipulation and agreement.[5] While the tracking and isolation method does not entirely shield EMW customers from all costs associated with serving Schedule SIL customers, they do serve as a non-SIL ratepayer protection.

Recommended Solution for energy imbalances

Q. What is Staff's preferred resolution of the energy issues you have identified thus far in your testimony?

A. Empire could request separate SPP settlement locations for customers as large as the expected LLCS customers, allowing for much cleaner tracking and assignment of actual costs incurred to serve each LLCS customer.

Q. Why should the load from these customers be accounted for differently than Empire's existing ratepayers?

A. Adding customers of this size is not typical business practice for Empire. The customers that are expected to be served are much larger than the largest current customers. It is imperative that Empire conducts due diligence when forecasting the loads of customers this large and avoids cross-subsidization from non-LLCS customers by combining the overall load forecast. Doing so is opaque and leads to added complication for identifying costs directly associated with what will be Empire's largest retail customers. Pairing the requirement that the rate schedule should "…prevent other customer classes' rates from reflecting any unjust or

[4] Staff has raised concerns in multiple cases regarding EMW's adherence to terms of the Stipulations and Agreements as well as inclusion of finite load projections from the Schedule SIL customer in the SPP Day-ahead bids.

[5] ER-2022-0130, EF-2022-0155, and EC-2022-0315.

unreasonable costs arising from service to such customers…"[6] with a request to serve the LLCS customers via a separate SPP commercial pricing node is a logical conclusion. Therefore, Staff recommends that the Commission order Empire to request separate SPP commercial pricing nodes for each LLCS customer which is contemplated, if not supported, by the SPP market protocols and designation of customers of this type as non-conforming load.

Ancillary Services

Q. Are there additional costs that may be realized through additions of LLCS customers?

A. Yes. Adding large amounts of load to the Empire system over a relatively short time frame also has the potential of adding additional costs for ancillary services.[7] Section 4.1.3. of the Market Protocols for SPP Integrated Marketplace describes the requirements that are generally related to Operating Reserve Requirements.[8] A brief description of Operating Reserve from the SPP website is listed below:

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[6] Section 393.130.7, RSMo (effective August 28, 2025), as enacted by Senate Bill 4 (2025).

[7] https://www.spp.org/glossary/?term=ancillary
Ancillary service - Generally refers to the services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. The Integrated Marketplace will set prices for certain ancillary services such as Operating Reserves, as part of both the Day-Ahead Market and the Real-Time Balancing Market

[8] https://www.spp.org/documents/71629/excerpt%20of%20appendix%20g%20mitigated%20offer%20methodogoloy%20integrated%20marketplace%20protocols%20106a%20reference%20doc%20for%20mdwg.pdf
4.1.3 Operating Reserve and, Instantaneous Load Capacity Requirements
SPP calculates the amount of Operating Reserve required for the Operating Day, on both a system-wide basis and a Reserve Zone basis, to comply with the reliability requirements specified in the SPP Criteria. Additionally, SPP calculates the amount of Instantaneous Load Capacity required for the Operating Day to ensure that unit commitment is sufficient to reliably serve load in real-time while maintaining the Operating Reserve requirements. SPP calculates the hourly Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, Ramp Capability Down, Uncertainty Reserve and Instantaneous Load Capacity requirements on an SPP BAA basis and calculates minimum Operating Reserve requirements and maximum Operating Reserve limitations for each Reserve Zone. (1) SPP BAA Contingency Reserve requirements are set consistent with SPP Criteria and may vary on an hourly basis. (2) SPP BAA Regulation-Up and Regulation-Down requirements are based upon a percentage of forecasted load, adjusted up or down to account for Resource output variability, and may vary on an hourly basis. (3) SPP BAA Instantaneous Load Capacity requirements are set to ensure that expected variations between instantaneous peak load for the interval and the average load forecast for that interval can be reliably served in real-time while simultaneously maintaining the SPP BAA Operating Reserve requirements (4) The SPP BAA requirements, minimum Reserve Zone Operating Reserve requirements and maximum Reserve Zone Operating

> Operating Reserve - Resource capacity held in reserve for resource contingencies and NERC control performance compliance which includes the following products: Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve.[9]

Q. Are these costs easily identifiable and would Staff be able to isolate them in the course of a general rate case or Fuel Adjustment Rate filing?

A. No. The changes to these costs would be difficult if not impossible to accurately isolate and quantify, but they should be considered as they could impact the overall costs to all Empire ratepayers through the FAC.

SPP Market Protocols for Non-Conforming Load

Q. Have recent SPP presentations provided additional support for Staff's recommendation regarding separate commercial pricing nodes for potential Empire LLCS customers?

A. Yes. In a recent presentation by SPP entitled LARGE LOAD STAKEHOLDER ENGAGEMENT FORUM,[10] SPP indicated that many of the customers that are sized consistent with those Empire customers that would be eligible for the LLCS tariff class would be considered non-conforming load customers. [11] SPP requires Market Participants with non-conforming load to provide additional forecasts for those entities.[12] The SPP market

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Reserve limitations are calculated and posted no later than 06:00 Day-Ahead. At this time, SPP will also communicate each Asset Owner's estimated Operating Reserve obligations in each Reserve Zone using the BAA Mid-Term Load Forecast and the Asset Owner load forecasts developed by SPP under Section 4.1.2.1.5. (5) These Operating Reserve requirements and limitations are used by SPP as inputs into the DA Market and RTBM clearing and RUC processes. (a) SPP may increase Operating Reserve requirements for use in RTBM clearing and RUC processes above the requirements used in the DA Market clearing, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions.

[9] https://www.spp.org/glossary/?term=operating+reserve

[10] Attached as JL-d2

[11] https://www.spp.org/documents/71629/excerpt%20of%20appendix%20g%20mitigated%20offer%20methodology%20integrated%20marketplace%20protocols%20106a%20reference%20doc%20for%20mdwg.pdf

[12] SPP requires the following for Non-Conforming Load in accordance with Section 4.1.2.1.2 of the Market Protocols for SPP Integrated Marketplace:
"Non-Conforming Load, as described in Section 6.2.2**, is more process driven and needs to be separated from the load forecast application because it does not follow a predictable pattern**. Load that is modeled to represent

protocols specify that the forecasts may be done for individual pricing nodes, as Staff is recommending. Based on the SPP requirements, Empire would likely already be required to do many of the forecasting tasks associated with having separate commercial pricing nodes.

Q. Why is Staff's recommendation the most reasonable solution to this complex issue?

A. Staff's recommendation for separate SPP commercial pricing nodes would allow for a much cleaner isolation of costs that are attributable to what will be Empire's largest customers and facilitate the Commission's ability to "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers."[13]

Conclusion on SPP costs related to Energy

Q. Please clearly indicate Staff's recommendation on this issue.

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the charging capabilities of ESRs not registered as an MSR must be considered a Non-Conforming Load. **Market Participants with registered Non-Conforming Load shall submit hourly load forecasts of Non-Conforming Load consumption to SPP before SPP begins the Day-Ahead RUC process for the Operating Day and for six (6) days following the Operating Day**. Once the initial submission is received before SPP begins the Day-Ahead RUC process, Market Participants are allowed to submit hourly load forecasts of Non-Conforming Load after SPP begins the Day-Ahead RUC process up to thirty minutes before the Operating Hour. **Market Participants are encouraged to submit a forecast of each registered Non-Conforming Load for two (2) hours following the current interval for each 15-minute interval that the forecast deviates from the hourly profile**. If the 15-minute forecast is unavailable, SPP shall interpolate using the submitted hourly Non-Conforming Load forecast. **Market Participants shall also submit a forecast on a 5-minute rolling 15-minute ahead basis**. The submitted Non-Conforming Load will be added to the conforming load forecasts to create the total SPP Forecast Area forecast. **Market Participants are required to submit actual Non-Conforming Load data for each Non-Conforming Load for which metering is available** or estimates of Non-Conforming Load for which metering is not available (submitted forecast value can be used as actual)." (**Emphasis added)**

Section 6.2.2 of the Market Protocols for SPP Integrated Marketplace goes on to state:

"Each Asset Owner must identify any Non-Conforming Load asset that the Asset Owner specifically forecasts and the PNode or Aggregate PNode (APNode) at which it resides. A Non-Conforming Load may only be represented by an APNode if the load is in the same location (e.g. a single industrial process served by more than one bus). For the purposes of this registration requirement, any Non-Conforming Load of 50 MW or greater must be identified."

[13] Section 393.130.7 RSMo (effective August 28, 2025), as enacted by Senate Bill 4 (2025).

A. Staff recommends that the Commission order in this case includes a condition that LLCS customers will be served via a separate commercial pricing node and that Empire develop sub-accounts that would allow for simple and concise tracking of many of the SPP costs directly associated with each customer.

<u>DEMAND RELATED SPP COSTS</u>

Penalties for Resource Adequacy shortfall

Q. Please describe SPP's penalty for Market Participants, such as Empire, that fail to fulfill the Resource Adequacy Requirements.

A. The SPP Open Access Transmission Tariff requires Deficiency Payments from:

"…a Market Participant when one or more of its LREs[14] has not met the Resource Adequacy Requirement as calculated in accordance with Section 14.2 of this Attachment AA."[15]

The Deficiency Payment is calculated by multiplying the Deficient Capacity[16] by the product of the SPP defined Cost of New Entry ("CONE")[17,18] and CONE Factor.[19]

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[14] Load Responsible Entities

[15] Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment AA Section 2 page 3

[16] "Resource Adequacy Requirement less the sum of Deliverable Capacity and Firm Capacity, or zero if the sum of Deliverable Capacity and Firm Capacity is greater than or equal to the Resource Adequacy Requirement." Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment AA Resource Attachment AA Resource Adequacy - Attachment AA Section 14 page 30.

[17] "The Cost of New Entry ("CONE") value shall be 85.61 $/kw-yr. The CONE value shall be reviewed on or before November 1st of each year by the Transmission Provider and any changes shall be filed with the Commission."

[18] The SPP defined CONE value has not been updated since July of 2018 and may be subject to future cost increases.

[19] Where the CONE FACTOR shall be:

(i) 125% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 8%; or

(ii) 150% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 3%, but less than the PRM plus 8%; or

(iii) 200% when the SPP Balancing Authority Area Planning Reserve is less than the PRM plus 3%.

The CONE Factor is currently a range of values between 125% and 200% based upon the SPP Balancing Authority Planning Reserve Margin. Essentially as the Planning Reserve Margins get tighter, the CONE Factor increases. Revenues from Deficiency Payments are then allocated to those LREs that have excess capacity.[20]

Recommended rates

Based upon the 2025 SPP Summer Resource Adequacy Report, the outlook for Existing SPP Balancing Area ("BA") Planning Reserve is greater than 8% through 2027 and anticipated SPP BA Area Planning Reserve (including new resources) is greater than 8% through 2030.[21] Therefore, the presumptive cost of any Deficiency Payment is approximately $107.02/kW-year at this time. Staff recommends that:

1. The approximated Deficiency Payment be used as the basis of a Demand Deviation Charge equal to $107.02 per kW to account for year over year changes to projected demand;
    a. to be applied as 12 equal monthly amounts for any deviations between initial contract demand and the current-year updated contract demand;
    b. Deviations from the original contract of less than +/-5% will not incur a penalty, however: (1) Deviations of more than +/-5% will be billed at $8.9177 per kW-month.
2. An Imbalance Charge, if applicable, for the difference between the current-year updated contract demand and the actual demand charge for Generation Capacity to account for imbalances in projected demand and actual demand.

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[20] Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment AA Resource Adequacy - Attachment AA Section 14 Attachment AA Section 14 pages 35-37.

[21] https://www.spp.org/documents/74099/2025%20spp%20summer%20resource%20adequacy%20report.pdf

a. This charge will be applied to the difference between the projected demand for each month and the actual demand realized during the demand window for that month at a rate of $8.9177 per kW.

Q. Why is it reasonable to charge LLCS customers for demand deviations in either direction?

A. Because deviations in either direction of the year over year projected demand could cause additional costs to be incurred, it is reasonable to apply a charge for both under- and over-projections to provide a financial incentive for LLCS customers to provide projections that are as accurate as possible for purposes of SPP Resource Adequacy Requirements. Put simply, if the projected demand estimate is too high, Empire might choose to acquire more capacity than necessary; conversely, if the projected demand estimate is too low, Empire might incur costs to acquire additional capacity or incur a Deficiency payment. Both of those outcomes have the potential to impact non-LLCS customers and should be mitigated or avoided to the extent possible.

The Imbalance Charge accounts for differences in realized demand during peak periods compared to the contracted demand for that year, providing the LLCS customer a financial incentive to operate consistent with the contracted demand.

Q. Would these charges be subject to change in future general rate proceedings?

A. Yes. The Demand Deviation Charge and Imbalance Charge should be revisited in future general rate cases to reflect changes in the SPP Deficiency Payment calculation, including but not limited to, timing of the measured demand (i.e. changes to seasonality), SPP Balancing Authority Area Planning Reserve, SPP calculated value of CONE, and the SPP CONE Factor.

In recent Empire IRP filings, Empire has indicated that the excess capacity from its existing resources compared to projected peak demands is dwindling. The 2025 SPP Summer Resource Adequacy Report[22] indicates Empire has approximately 9 MW of excess capacity. Given the size of the customers contemplated by Empire's LLCS tariff and Empire's projected pipeline of potential LLCS customers, Empire ratepayers face increased risk of being subject to Deficiency Payments as a direct result of LLCS customers being integrated into the Empire system prior to additional generation being built. Staff recommends that any Deficiency Payment incurred after the addition of LLCS customers be borne solely by the LLCS customer class in proportion to the overall peak demand of each customer.

Q. Does this conclude your direct testimony?

A. Yes it does.

[22]https://www.spp.org/documents/74099/2025%20spp%20summer%20resource%20adequacy%20report.pdf#:~:text=The%20purpose%20of%20this%20report%20is%20to%20provide,season%2C%20all%2064%20LREs%20have%20met%20the%20RAR.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in Its Missouri Service Area	)))))	Case No. ER-2024-0261

AFFIDAVIT OF J LUEBBERT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW J LUEBBERT and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Direct Testimony of J Luebbert*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

J LUEBBERT

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 18th day of July 2025.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2029
Commission Number: 12412070

Notary Public

Credentials and Background of
J Luebbert

I have a Bachelor of Science degree in Biological Engineering from the University of Missouri. My work experience prior to becoming of member of the Missouri Public Service Commission Staff includes three years of regulatory work for the Missouri Department of Natural Resources.

I am currently employed as the manager of the Tariff/Rate Design Department of the Industry Analysis Division of the Missouri Public Service Commission Staff. Prior to holding my current position, I was employed as Case Manager of the Commission Staff Division, Associate Engineer of the Engineering Analysis Department of the Industry Analysis Division, and as a Utility Engineering Specialist III in the Energy Resources Department of the Commission Staff Division. I have been employed at the Missouri Public Service Commission since March 2016 and am responsible for preparing staff recommendations and ensuring that Staff presents recommendations in a neutral, independent manner to inform the Commission of Staff's position and possible alternatives.

Case Participation of
J Luebbert

Case Number	Company	Issues
EO-2015-0055	Ameren Missouri	Evaluation, Measurement, and Verification
EO-2016-0223	Empire District Electric Company	Integrated Resource Planning Requirements
EO-2016-0228	Ameren Missouri	Utilization of Generation Capacity, Plant Outages, and Demand Response Program
ER-2016-0179	Ameren Missouri	Heat Rate Testing
ER-2016-0285	Kansas City Power & Light Company	Heat Rate Testing

Case Number	Company	Issues
EO-2017-0065	Empire District Electric Company	Utilization of Generation Capacity and Station Outages
EO-2017-0231	Kansas City Power & Light Company	Utilization of Generation Capacity, Heat Rates, and Plant Outages
EO-2017-0232	KCP&L Greater Missouri Operations Company	Utilization of Generation Capacity, Heat Rates, and Plant Outages
EO-2018-0038	Ameren Missouri	Integrated Resource Planning Requirements
EO-2018-0067	Ameren Missouri	Utilization of Generation Capacity, Heat Rates, and Plant Outages
EO-2018-0211	Ameren Missouri	Avoided Costs and Demand Response Programs
EA-2019-0010	Empire District Electric Company	Market Protection Provision
GO-2019-0115	Spire East	Policy
GO-2019-0116	Spire West	Policy
EO-2019-0132	Kansas City Power & Light Company	Avoided Cost, SPP resource adequacy requirements, and Demand Response Programs
ER-2019-0335	Ameren Missouri	Unregulated Competition Waivers and Class Cost Of Service
ER-2019-0374	Empire District Electric Company	SPP resource adequacy
EO-2020-0227	Evergy Missouri Metro	Demand Response programs
EO-2020-0228	Evergy Missouri West	Demand Response programs
EO-2020-0262	Evergy Missouri Metro	Demand Response programs
EO-2020-0263	Evergy Missouri West	Demand Response programs
EO-2020-0280	Evergy Missouri Metro	Integrated Resource Planning Requirements
EO-2020-0281	Evergy Missouri West	Integrated Resource Planning Requirements
EO-2021-0021	Ameren Missouri	Integrated Resource Planning Requirements
EO-2021-0032	Evergy	Renewable Generation and Retirements
GR-2021-0108	Spire Missouri	Metering and Combined Heat and Power
ET-2021-0151	Evergy	Capacity costs
ER-2021-0240	Ameren Missouri	Market Prices, Construction Audit, Smart Energy Plan, AMI
ER-2021-0312	Empire District Electric Company	Construction Audit, Market Price Protection, PISA Reporting

Case Number	Company	Issues
EO-2022-0193	Empire District Electric Company	Retirement of Asbury
ER-2022-0129	Evergy Missouri Metro	MEEIA annualization
ER-2022-0130	Evergy Missouri West	MEEIA annualization, Schedule SIL revenue and incremental costs
EF-2022-0155	Evergy Missouri West	Customer event balancing
EC-2022-0315	Evergy Missouri West	Compliance with Stipulation and Agreement, Commission Order, and Schedule SIL
GR-2022-0179	Spire Missouri	Compressed Natural Gas
EA-2022-0244	Ameren Missouri	Huck Finn Solar CCN
EA-2022-0245	Ameren Missouri	Boomtown Solar CCN
EA-2022-0328	Evergy Missouri West	Persimmon Creek CCN
ER-2022-0337	Ameren Missouri	Billing determinant adjustments
EA-2023-0286	Ameren Missouri	Solar CCNs
EO-2024-0002	Evergy Missouri West Evergy Missouri Metro	Data retention
EO-2023-0136	Ameren Missouri	MEEIA program design, avoided costs
EO-2023-0369 EO-2023-0370	Evergy Missouri Metro Evergy Missouri West	MEEIA program design, tariffs
EA-2024-0237	Ameren Missouri	Economic Feasibility
EA-2024-0292	Evergy Missouri West	Economic Feasibility and Decisional Prudence
EA-2025-0075	Evergy Missouri West	Economic Feasibility and Decisional Prudence
EA-2025-0087	Ameren Transmission Company of Illinois	Economic Feasibility

SPP Southwest Power Pool

LARGE LOAD STAKEHOLDER ENGAGEMENT FORUM

JULY 1, 2025

1:00 PM – 4:00 PM

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

SouthwestPowerPool

SPPorg

southwest-power-pool

SPP Southwest Power Pool

OPENING REMARKS & FORUM KICKOFF

LANNY NICKELL
PRESIDENT AND CHIEF EXECUTIVE OFFICER

“We’re at a turning point. This isn’t just about adapting to growth — it’s about leading it."

ADMINISTRATIVE ITEMS AND OBJECTIVES

DEREK WINGFIELD

MANAGER, COMMUNICATIONS

SPP ANTI-TRUST NOTICE

SPP strictly prohibits use of participation in SPP activities as a forum for engaging in practices or communications that violate the antitrust laws.

Please avoid discussion of topics or behavior that would result in anti-competitive behavior, including but not limited to, agreements between or among competitors regarding prices, bid and offer practices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that might unreasonably restrain competition.

This meeting is being recorded.

By continuing to be in the meeting, you are consenting to be recorded.

ACCESSIBILITY

- We strive to host inclusive, accessible meetings and experiences that enable all individuals to engage fully
- To request an accommodation or for inquiries about accessibility, please contact any SPP presenter, facilitator or meeting hosts. We will do our best to help

TODAY'S AGENDA

- **Welcome & Administrative Items**
- **Stakeholder Engagement**
- **Forum Overview**
- **SPP Large Load Integration Solution**
- **Timeline and Next Steps**
- **Moderated Questions and Discussion**
  - Pre-submitted Questions
  - Chat-submitted Questions
  - Open Forum Questions

PRINCIPLES FOR FORUM PARTICIPATION

WAIT TO RAISE YOUR HAND until after the end of the Q&A presentation, and after staff have answered questions submitted by stakeholders in advance.

ENGAGE: Send your questions through chat during presentations. Raise your hand to participate in Q&A at the end of the forum. A survey option will also be available to submit additional questions or responses after the forum.

RESPECT others' time. Everyone has the right to participate once before anyone speaks twice. Please keep your comments and questions concise to allow time for others.

DISCUSSION OBJECTIVES

- Large Load Growth
- SPP Opportunities and Challenges
- Objectives and Proposed Solution
- Next Steps

Review existing opportunities and challenges to connect large loads and offer solutions that position SPP as the High Impact Large Load RTO of choice

ACCELERATING HIGH IMPACT LARGE LOAD INTEGRATION

SPP Southwest Power Pool

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

SouthwestPowerPool SPPorg southwest-power-pool

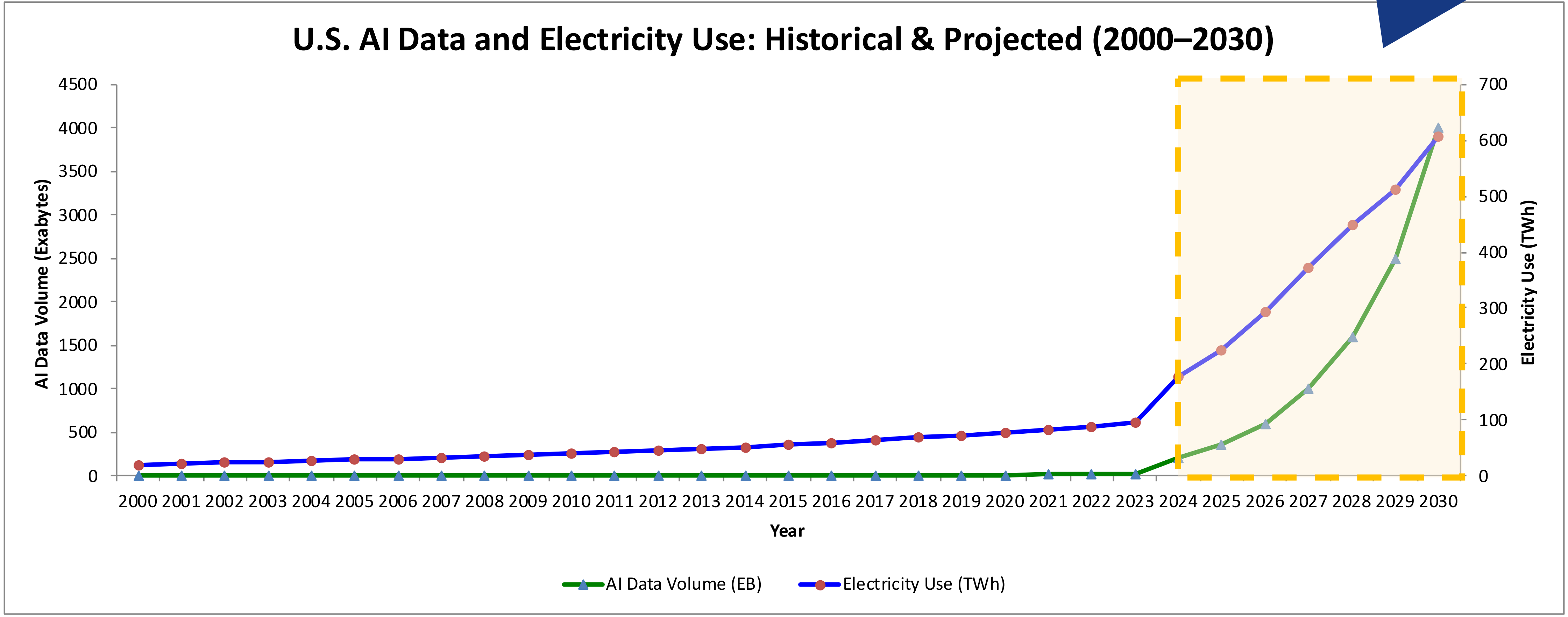
SPP Southwest Power Pool

LARGE LOAD GROWTH: OPPORTUNITIES & CHALLENGES

ANTOINE LUCAS
CHIEF OPERATING OFFICER

AI DATA AND ENERGY FUTURE

Data centers could account for **44% of U.S. electricity load growth** from 2023 to 2028



Exponential AI data and energy needs expected through the balance of the decade

Sources: McKinsey: "AI's Power Binge" [link], IEA, "AI is set to drive surging electricity demand from data centres" [link], Goldman Sachs "AI to drive 165% increase in data center power demand by 2030" [link]

AI DRIVEN LARGE LOAD GROWTH

Opportunity	Impact	Challenges	Impact
Accelerates economic GDP growth	AI could add **$15 trillion** globally and **$4 trillion** in the US by 2030	Job displacement risks	Up to **30% of US jobs** could be automated by 2030
Drives global innovation	US produces **~30% of AI research papers** worldwide	Ethical & privacy concerns	**60% of consumers** worry about AI privacy
Strengthens national security	US AI defense spending estimated at **$18 billion** annually	Geopolitical competition	China invested **$70 billion** in AI by 2025; global race risks
Attracts top global talent	US hosts **7 of the top 10 universities for A.I.**	Environmental & energy strain	AI data centers projected to use **5-8% of US electricity by 2030**; may drive **2-7% annual increases in electricity rates**
Benefits multiple sectors (healthcare, manufacturing)	AI could boost healthcare productivity by **40%**	Industry concentration risks	Top 5 US tech firms hold **>75%** of AI patent share

Opportunities exist for the U.S. to lead in the AI and Technology revolution

OTHER TYPES OF LARGE LOAD

Load Type	Description	Typical Size (MW)	Typical Voltage	Load Profile	Ramping Ability	Appetite for Demand Response
Data Centers	Facilities for computing infrastructure for data processing & storage	10 – 100+	13.8 kV – 230 kV	Flat, continuous, 24/7 operation	Low	Low
Cryptocurrency Mining	High-power computing for blockchain operations	5 – 100+	13.8 kV – 230 kV	Flat, responsive to price signals	High	High
Manufacturing (Heavy Industry)	Steel, cement and auto plants	20 – 500+	69 kV – 345 kV	Cyclical, shift-based	Low	Low
EV Charging Hubs	High-power fast-charging stations	1 – 50	13.8 kV – 115 kV	Peaky, high during travel demand	Medium	Medium
Waste/water Treatment	Water intake, pumping and treatment	5 – 100	13.8 kV – 115 kV	Generally flat with time-of-day variation	Low	Low
Mining Operations	Extraction and primary processing of minerals	10 – 300+	69 kV – 230 kV	Shift-based, varies with production	Low to Medium	Medium
Oil & Gas Facilities	Refineries, LNG, compressor stations	10 – 500+	69 kV – 345 kV	Continuous with routine maintenance	Low	Low
Green Hydrogen Production	Electrolysis facilities for hydrogen generation	20 – 300+	69 kV – 230 kV	Controlled, linked to renewables or pricing	High	High
Agricultural Processing	Grain drying, food processing, cold storage	5 – 50	13.8 kV – 69 kV	Seasonal with steady processing demand	Medium	Medium
Battery Energy Storage (BESS)	Grid-scale battery systems	10 – 500+	13.8 kV – 230 kV	Dynamic, driven by grid needs	Very High	Very High

Not just A.I.: other large loads are contributing to rapid demand growth

THE UNIQUE OPPORTUNITY FOR SPP

Leverage SPP’s wholesale market to offer a region of choice for large loads that value market transparency and price responsiveness	Central U.S. geography, grid connectivity and affordability offer an ideal location for large loads to connect	Catalyze economic development and desirable load growth by partnering with members and to align incentives with grid capacity	Lead the way for grid-friendly load integration, making SPP a model for balancing high-demand customers with grid reliability	Leverage SPP’s diverse generation profile to attract forward focused large loads

SPP has a unique opportunity to offer reliable, scalable and cost-effective solutions for the next generation of data and manufacturing loads

REGIONAL CHALLENGES

Transmission Customer	▪ Transmission Customers (TC) and large loads are often unable to commit to projects due to uncertainty of cost, timing and operating requirements ▪ While both are well capitalized and motivated, large loads seek 24/7 operation with limited interest/ability to curtail loads
SPP	▪ Deliberate pace of current planning processes not consistent with market needs and will drive large loads to more responsive regions ▪ Must connect large loads in a manner that does not sacrifice reliability ▪ Minimize cost shifts from large loads to other customers

SPP must expeditiously develop modernized and timely planning processes to support large loads

SPP'S LARGE LOAD INTEGRATION SOLUTION

CASEY CATHEY,
VP ENGINEERING

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

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OUR VALUE PROPOSITION

SPP

Our Challenge

- Timing / Lack of Cost Clarity
- Limited Existing Solutions

Our Objectives

- 90-day Connection Study
- Path to Connect Supporting Gen
- Balance Reliability

Our Solution

- Fastest Connection Study in U.S.
- Flexible Options
- Interconnection Cost Clarity

Our Results

- Economic Development
- Leader in Large Load Integration
- Load Growth Enablement

Our solution directly addresses industry need through leading innovation

Our Vision

We must develop an **industry-leading** and **immediately available** solution that enables the **timely and reliable** integration of large loads, including those with **supporting generation**, through a streamlined, scalable process that provides **improved timing** and **cost clarity** to transmission customers.

Our Guiding Principles

Inspire mindsets and employ innovative, **art-of-the possible** thinking
Prioritize reliability with focused and timely studies that address key risks
Accelerate our ability to study large loads and supporting generation within **90 days**
Provide **cost clarity** by leveraging existing cost assignment structures
Leverage an agile and engaged **stakeholder process**
Where possible, find solutions that utilize **existing tariff authority**
Ensure **solution flexibility** to manage volume and operating complexity

Target: A comprehensive, industry-leading, 90-day solution available immediately

OUR EXISTING SOLUTIONS FOR LOAD

Aggregate Transmission Service Studies (ATSS)

For those with sufficient generation, willing to wait for transmission upgrades, but needing to secure designated network capacity:

- Biannual study
- Robust study of load addition
- Firm transmission service
- Upgrades are base plan funded

Limitations of ATSS: Biannual studies limit times to request and result in additional wait time.

Attachment AQ Delivery Point Assessment

For those with sufficient generation and willing to wait for transmission upgrades, AQ provides a study process to add new delivery points to enable business decisions:

- Studied in 90 days
- Firm transmission service can be added with ATSS
- Upgrades are base plan funded

Limitations of AQ Study: This is not an option without available network resource capacity.

Attachment AX* Provisional Load Process

Study and *provisional* approval for customers with plans to *acquire* generation:

- Studied in 90 days
- Does not require current gen or GIA to study
- Upgrades are directly assigned until the customer acquires firm service for the new generation

Limitations of AX Study: Load may connect but would be subject to unreserved use charges if firm transmission is not acquired

SPP has an opportunity to close the gaps left by existing solutions

[1] *Attachment AX is currently pending review at FERC. SPP requested an August 4, 2025, effective date.*

Existing Solution Gaps

- Long wait times
- Limited answers for “high impact” large loads if the generation or GIA doesn’t already exist
- Lack of flexibility for limited connection or operation of load within system limits
- Transmission upgrade cost uncertainty

What is a "High-Impact Large Load" (HILL)?

A HILL is any commercial or industrial individual load facility or aggregation of load facilities at a single site connected through one or more shared points of interconnection or points of delivery that can pose reliability risks to the grid.

HILLs are deemed Non-Conforming Loads. A load may be considered a HILL if the point of interconnection kV level is:

- 69kV or below and the HILL peak demand is 10MWs or greater
- Greater than 69kV and the HILL peak demand is 50MWs or greater

SPP

What is Conditional High Impact Large Load Service (CHILLS)?

CHILLS is a new type of transmission service available to High Impact Large Load for the transfer of energy to designated point(s) of delivery to serve the Conditional High Impact Large Load (CHILL) of a transmission customer or a network customer.

CHILLS will be available for yearly periods ranging from one to five years.

SPP

What is a Conditional High Impact Large Load (CHILL)?

A CHILL is the portion of a HILL that is receiving Conditional High Impact Large Load Service (CHILLS).

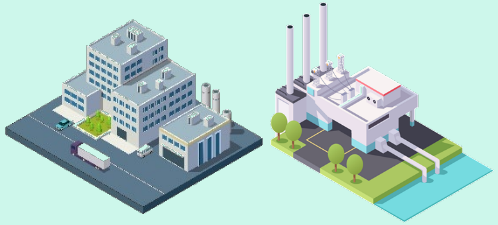
This is intended for any specifications of the HILL, including term of service, that cannot be reliably served on a firm basis by existing designated resources or the current transmission system.

CHILL can exist at the same delivery point as firm load.

OUR PROPOSED SOLUTIONS FOR HIGH-IMPACT LARGE LOADS

Conditional High Impact Large Load Service (CHILLS)

- Study in 90 days, provided all data is received and agreement signed
- Allows faster load connection with certain reliability-driven conditions
- Expected to transition to firm service within five years
- HILLGA optional, not required



Gen supported HILL GI Assessment (HILLGA)

- Gen *and* load studied in 90 days, pending data and agreements*
- Connect generation to serve the energy demand of the HILL or CHILL
- Generation may elect to be limited to serve a local area or pursue full interconnection service

Our proposed solutions provide more certainty for timing and cost

**Provided agreements are received for both the HILL or CHILL and the supporting generation.*

PROPOSED SOLUTIONS: WHAT CHILLS WILL DO

Results will be provided in <u>90 days*</u>. This is for entities who <u>do not want to wait</u> for generation and transmission to get built before beginning operation. CHILLS will be billed at reserved capacity MWs unless curtailed, then curtailed MWs will be billed

Scenarios:

- Transmission Customer <u>does have</u> sufficient generation, GIA, or planned generation to serve load, but <u>does **not** have</u> transmission capacity to deliver energy to the load

or

- Transmission Customer <u>does **not yet**</u> have sufficient generation, but load will accept limited service until sufficient capacity is available, and any transmission system upgrades are completed

Our proposed solutions provide more certainty for timing and cost

**Provided all data is received and agreements are signed.*

PROPOSED SOLUTIONS: WHAT HILLGA WILL DO

Results will be provided in 90 days* for new supporting generation and large load. New supporting generation will be studied with the load it will serve. This option is available for both CHILL and firm HILL loads.

Load with Supporting Generation Scenarios:

- Transmission Customer does **not** have sufficient generation, GIA, or planned generation to serve load

or

- Transmission Customer does have sufficient generation, GIA, or planned generation but the large load would rather pursue different generation to serve the load

Our proposed solutions provide more certainty for timing and cost

**Provided all data is received and agreements are signed. Deliverability area resources may require additional study.*

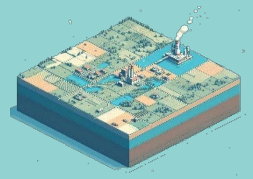
PROPOSED PATHS FOR LOAD AND SUPPORTING GENERATION

Common Bus

- Study delivered in 90 days*
- HILL or CHILL and supporting generation are behind the same point of interconnection
- Generation will not be injected to the grid

Local Area

- Study delivered in 90 days*
- HILL or CHILL and supporting generation are within two buses
- Energy flow on the grid will be limited by HILL's need and system capacity
- 5-year service term



Deliverability Area

- Studies delivered in 90 days*
- HILL or CHILL and supporting generation are in same deliverability area
- Energy limited by HILL's need plus reserve, and a multiplier
- Customer may pursue NRIS or interim service
- Transmission service requires an additional designation process

Our proposed solutions provide more clarity for timing and cost

**Provided all data is received and agreements are signed*

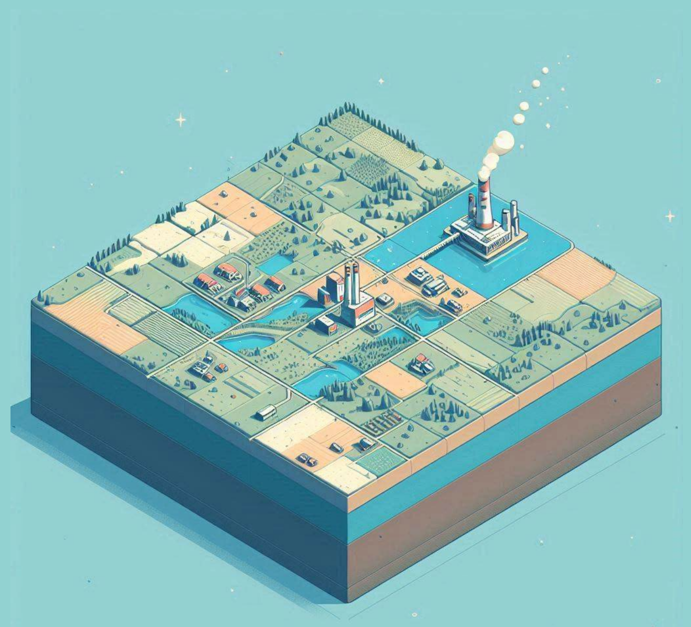
HILLGA PATH 1: COMMON BUS

- For HILL or CHILL and supporting generation behind the same delivery point
- Generation will be configured for zero injection onto the transmission system
- Generation greater than 10 MW must be market registered
- Separate metering required for each load and generator
- No net metering for billing purposes
- Studied in 90 days by SPP or an equivalent stability study done by the TO
- If study shows potential impacts to the transmission system, the generation must be studied under the longer DISIS process

HILLGA PATH 2: LOCAL AREA

- Gen can connect to more than one HILL or CHILL
- HILL and generation are in same “local area”
  - Using no more than 5 substations
  - Using no more than 2 transmission lines
  - Each load within 2 substations of generation
- Generation is required to limit output to the amount of HILL(s) considered in the agreement
- Supporting generation is capped at load max plus reserve margin x 1.25
- Service is interim for 5 years, which should be sufficient for the generation and load to be considered planned sites and subject to the planned CPP GRID-C fee

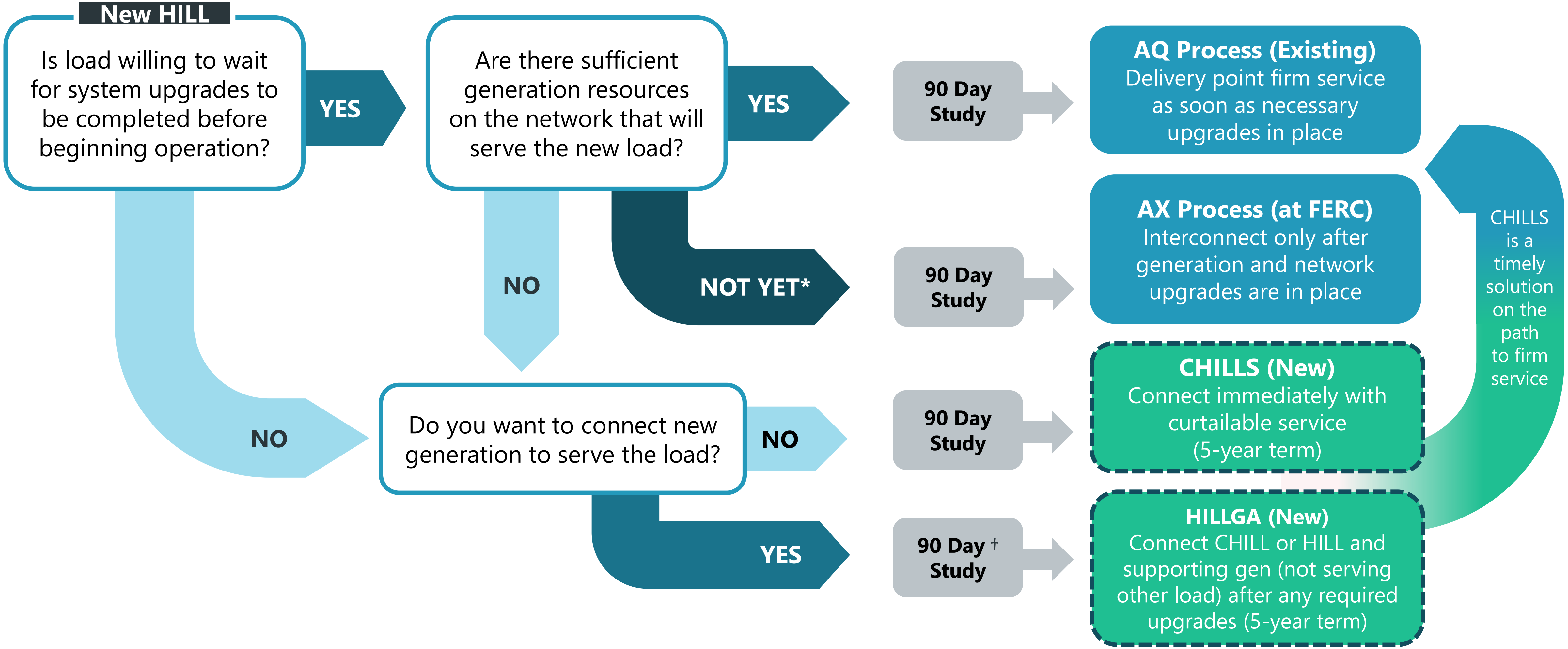
HILLGA PATH 3: DELIVERABILITY AREA



- HILL or CHILL and generation are in the same deliverability area
- Studied within 90 days* to determine costs for Network Resource Interconnection Service (NRIS) service
- Generation must be capable of a ramp rate of 20 MW/min and a total ramp equal to or greater than 50% of the HILL
- Projected accreditation must be equal to or greater than the HILL
- Supporting generation NRIS value is capped at load max plus reserve margin x 1.25
- Once granted, the NRIS service is permanent
- This Path 3 *process will sunset* with implementation of the CPP and its GRID-C fee requirements

**Does not include resource designation and Z2 assessment.*

HOW A NEW LOAD CAN GET CONNECTED IN SPP



Load may pursue multiple paths (AQ, AX, CHILL) simultaneously.

*"**Not Yet**": the utility has pending generation with rights (GIA), or planned generation

†HILLGA for "Common Bus" and "Local Area" to be completed in 90 days. HILLGA for larger "Deliverability Zone" requires additional study.

LARGE LOADS IN RESOURCE ADEQUACY

- Loads with conditional service (CHILL) will be considered non-market registered demand response for purposes of resource adequacy (RA) requirements.
- CHILL loads will be seen as non-market registered demand response for RA. Forecasts should follow current practices and will be subject to new demand response (DR) framework and LRE peak demand assessment.
- LREs must report CHILLS in their RA workbook
- Common bus generation can be attested as firm power for meeting resource adequacy (RA) requirements.
- Local area generation can achieve firm service with either aggregate study process or secondary network service

LARGE LOADS IN OPERATIONS

- HILL and CHILL will be subject to industry-leading requirements to mitigate reliability issues seen around the globe.
- Transmission and network customers must comply with ride-through requirement guidelines in Integrated Marketplace Market Protocols.
- CHILLs are subject to curtailment, in whole or in part, for reliability reasons when an emergency condition or other unforeseen condition threatens to impair or degrade the reliability of the transmission system or the systems directly or indirectly interconnected with the transmission system.
- HILLs are subject to Firm Load Shed and Transmission Emergency.

PROPOSED SOLUTIONS: A COMPARISON

	High Impact Large Loads	
	HILL with Firm Service	HILL with CHILLS
Study Timing	90 Days	90 Days
Transmission Service Type	Firm (AQ*)	CHILLS Non-Firm, up to Five-Year Interim (transition to firm using AQ or AX)
Resource Adequacy (RA) and Demand Response (DR)	Eligible as Market Registered or Reliability Registered DR Resource (MRDR, RRDR)	Curtailable Load - Not eligible as RRDR or MRDR
Load		
Curtailability	Firm Load Shed and Transmission Emergency	Advisories, EEAs and Transmission Mitigation
Market Registration	Non-Conforming Load	Curtailable, Non-Conforming Load
Metering	Required	Required
Demand Response Resource	Eligible	Curtailable load, will be DR for RA
Network Upgrades	Base Plan Funding Eligible†	Sponsored Upgrades

**Attachment AX provides a provisional path to achieve firm service if generation is not yet available to serve load*

†Under Attachment AX, upgrade costs are initially directly assigned. Remaining ATRR is eligible for base plan funding after generation is secured.

NEXT STEPS

ERIN CATHEY,
SUPERVISOR, MARKET
POLICY COORDINATION

KEY EXECUTION DATES

June	**Stakeholder Outreach**
June 30	**RR** Posted
July 1	Large Load **Stakeholder Engagement Forum**
July 8	**CAWG** Education
July 15	**MOPC** Policy Endorsement
July 17	**SPC** Education
Aug. 4	**RSC** Education
Aug. 5	**BOD** Approval [1]

Target Effective Timing

Pre-approval submissions: August 2025 | Effective: Winter Season 2025/2026
(Timing contingent on implementation complexity and vendor availability.)

[1] *Unless earlier approval by the Board, if a meeting the week of July 21 determined to be desirable.*

SPP Southwest Power Pool

QUESTIONS & DISCUSSION

DEREK WINGFIELD,
MANAGER, COMMUNICATIONS

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PRE-SUBMITTED QUESTIONS

WHAT NEW QUESTIONS DO YOU HAVE?

Use Webex raise hand feature to join the queue

THANK YOU FOR YOUR ENGAGEMENT

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