

ENERGY RESOURCE INTERCONNECTION SERVICE IN THE SOUTHWEST POWER POOL

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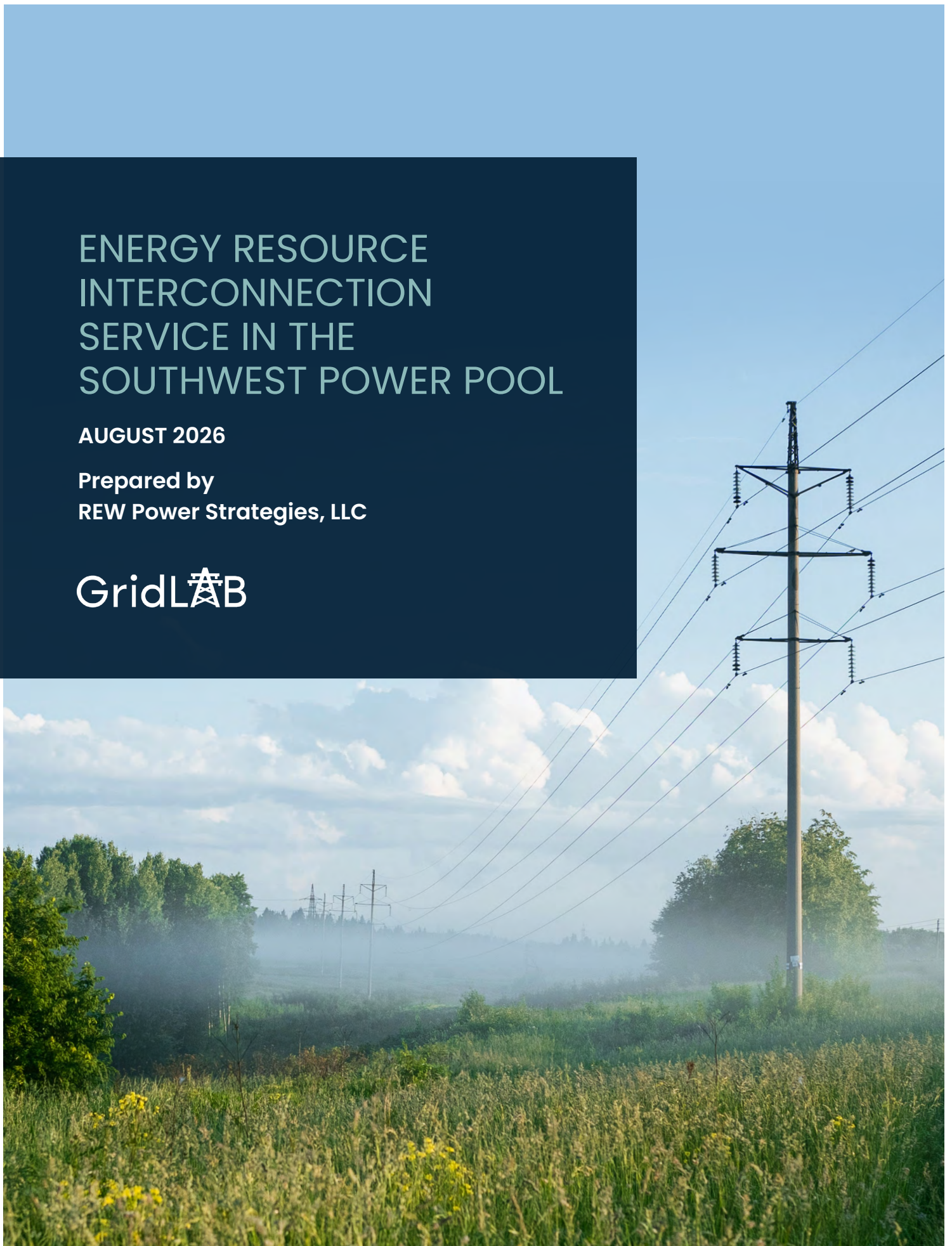


Table of Contents

1 Introduction: ERIS in Southwest Power Pool	1
2 ERIS in Transmission Planning and Generator Interconnection Assessments	2
3 ERIS and the Day-Ahead Market	4
4 ERIS in Real-Time Operations and Curtailment Processes	6
5 ERIS and Energy-Only Interconnection in Other Markets	9
Conclusion	10

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Purpose. This paper explains how Energy Resource Interconnection Service (ERIS) functions within Southwest Power Pool (SPP), with emphasis on the separation between interconnection rights, transmission planning, resource adequacy, market participation, and real-time congestion management. It also compares SPP's framework with analogous constructs in other organized markets.

1 | INTRODUCTION

ERIS in Southwest Power Pool

Energy Resource Interconnection Service is the foundational generator interconnection product created by the Federal Energy Regulatory Commission (FERC) in Order No. 2003 and incorporated into SPP's Open Access Transmission Tariff. In practical terms, ERIS permits a generating facility to connect to the transmission system and inject energy up to the level established in its Generator Interconnection Agreement, subject to the availability of transmission capacity and the operating limits of the system. It is the basic service required for a new transmission-connected generator to become electrically interconnected and eligible to participate in SPP's Integrated Marketplace.

ERIS does not reserve transmission capacity from the generator to a particular load, does not make the resource a designated network resource, and does not guarantee that the generator's full output can be delivered during every operating condition. FERC's pro forma definition expressly contemplates that an ERIS resource may be curtailed when transmission capacity is unavailable, in a manner comparable to non-firm point-to-point transmission service. SPP's market dis-

patch can economically use an ERIS resource when the system can accommodate its output, but the resource remains exposed to congestion, redispatch, and other reliability limitations.

The Tariff Attachment AA includes resource adequacy requirements (RA) for Load Responsible Entities (LRE's) for summer and winter periods. SPP currently has a summer RA requirement of 16% and a winter requirement of 36%, both of which will be increasing in the near future. LRE's are required to have firm capacity accredited under an Effective Load Carrying Capability (ELCC) test. ERIS resources are not considered eligible for meeting the RA requirement.

The SPP market has a summer peak load obligation of approximately 56,000 MW (excluding the recently added Western Interconnection expansion) and total registered generation in the market of over 100,000 MW. To meet the minimum RA summer requirement approximately 65,000 MW of generation must be firm network resources or NRIS. The remaining 35,000 MW of generation is a combination of ERIS and NRIS generation.

2 | ERIS in Transmission Planning and Generator Interconnection Assessments

ERIS enters the SPP planning framework first through the generator interconnection process. The purpose of that process is not to determine whether a project is economically desirable or whether a load-serving entity needs the project. Rather, it determines the facilities and upgrades necessary to connect the project without violating applicable reliability criteria under the study assumptions. The interconnection process evaluates the project at its requested point of interconnection, size, technology, and operating characteristics, and it identifies impacts on both the SPP transmission system and affected neighboring systems.

2.1 Scope of an ERIS interconnection assessment

- Power-flow analysis to identify thermal and voltage violations caused or aggravated by the proposed interconnection under specified base cases and contingencies.
- Short-circuit analysis to determine whether fault-duty limits or protective-device capabilities are exceeded.
- Stability analysis, where applicable, to evaluate transient, voltage, frequency, and control-system performance.
- Identification of interconnection facilities, network upgrades, and affected-system impacts necessary to permit the requested injection reliably.
- Evaluation of operating limitations or interim operating arrangements when all required upgrades will not be in service by the requested commercial-operation date.

An ERIS study should not be read as a finding that the project is deliverable throughout the SPP footprint at its full nameplate output. Instead, the study establishes a reliable interconnection under the applicable ERIS modeling standard. In actual operations, the dispatch pattern, outages, load level, topology, neighboring-system conditions, and output of other resources will differ from the planning cases. Congestion can therefore arise even when the generator has completed all assigned interconnection upgrades.

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2.2 Relationship to regional transmission planning

SPP's regional transmission planning processes evaluate broader reliability, economic, policy, and load-serving needs. The Integrated Transmission Planning process and newer Consolidated-Planning Process (CPP) initiatives use forecasts of load, resource additions and retirements, market outcomes, and system conditions to identify regional solutions. ERS projects may be modeled as part of those futures, but the existence of an ERS Generator Interconnection Agreement does not, by itself, compel SPP to build a regional transmission portfolio that makes every megawatt of that resource deliverable under all conditions.

The interconnection process addresses project-driven reliability impacts under prescribed assumptions; regional planning determines whether additional transmission is justified for broader regional benefits.

This separation can create a planning gap. A large volume of ERS generation, such as wind, may be electrically connected and economically attractive, yet its output may be concentrated behind transmission constraints. The interconnection process addresses project-driven reliability impacts under prescribed assumptions; regional planning determines whether additional transmission is justified for broader regional benefits. When those two processes use different assumptions, timelines, cost-allocation rules, or resource-certainty thresholds, congestion and curtailment risk can persist after interconnection.

3 | ERIS and the Day-Ahead Market

SPP's Integrated Marketplace includes a Day-Ahead Market, Reliability Unit Commitment processes, and a Real-Time Balancing Market. The Day-Ahead Market co-optimizes energy and operating reserves on participant offers, bids, self-schedules, transmission constraints, and other market inputs. ERIS resources may participate when registered and otherwise eligible, **but the interconnection service level (NRIS or ERIS) does not provide a preferred dispatch rank, a guaranteed day-ahead award, or immunity from congestion.** Commitment and dispatch are determined through SPP's security-constrained economic dispatch (SCED) market optimization and reliability processes.

3.1 Distinction from Attachment AA resource adequacy

The Day-Ahead must-offer requirement must be distinguished from the resource-adequacy obligation imposed on Load Responsible Entities under Attachment AA. Attachment AA requires an LRE to demonstrate adequate qualified capacity for its seasonal net peak demand plus the applicable planning reserve margin. That is a forward-looking capacity demonstration. Attachment AE, Section 2.11.1, is an operating-day market conduct requirement designed to ensure that Market Participants with generation serving load offer an

adequate portion of their available supply into the Day-Ahead Market.

The two frameworks are related but not interchangeable. A resource or firm purchase may qualify for an Attachment AA capacity demonstration under the applicable accreditation and deliverability rules, while the physical resource is still offered and dispatched through Attachment AE. Conversely, an ERIS generator may be offered into the Day-Ahead Market and count toward the limited must-offer calculation even though its capacity does not qualify as firm capacity for a specific LRE's Attachment AA showing.

3.2 The limited Day-Ahead Market must-offer requirement

In addition to the forward-looking resource-adequacy requirements in Tariff Attachment AA, SPP has a separate limited must-offer obligation in the Day-Ahead Market. The operative requirement is found in Attachment AE, Section 2.11.1, titled "Day-Ahead Market Must-Offer Requirement." It applies on an Asset Owner basis to a Market Participant that has generation resources serving load. Although the policy is often described as an LRE must-offer requirement, the tariff provision is administered through the Market Participant and Asset Owner registration structure used in the Integrated Marketplace.

For each applicable hour in the DA, the Market Participant must generally satisfy one of two alternatives for the Asset Owner: (1) offer all available resource capacity that is not in an outage status, or (2) offer sufficient net resource capacity, together with qualifying firm power purchases and after accounting for firm power sales and Operating Reserve obligations, to cover at least 90 percent of the applicable load obligation. The 90 percent standard functions as a 10 percent tolerance band rather than as a requirement that every megawatt of forecasted load be backed by an individual generator with NRIS. The calculation focuses on the portfolio offered for the Asset Owner and recognizes eligible firm transactions in determining compliance.

If neither alternative is met for an Asset Owner in an hour, the Market Participant may be deemed noncompliant under Attachment AE, Section 2.11.1. The associated sanctions are contained in Attachment AF, Section 3.9, “Sanctions for Noncompliance with the Day-Ahead Market Must Offer Requirement.” That provision assesses a penalty for withheld capacity below the 10 percent tolerance band, using the tariff-prescribed methodology. The SPP Market Monitoring Unit monitors compliance and may evaluate whether reported outages, firm purchases, firm sales, load, reserve obligations, and offered capacity support the participant’s compliance position.

3.3 Relationship to ERIS and NRIS

The Day-Ahead must-offer requirement does not convert ERIS generation into firm transmission service or make ERIS capacity fully deliverable to load. An ERIS resource can be included in the offered portfolio and can clear

the Day-Ahead Market, but its output remains subject to the transmission constraints represented in the market model. **Likewise, NRIS does not guarantee a day-ahead award or create a higher economic dispatch priority.** ERIS and NRIS describe the interconnection study standard and associated network-upgrade responsibility; the must-offer rule addresses whether the Market Participant has made sufficient supply available to the Day-Ahead Market.

Accordingly, a Market Participant may rely on ERIS resources as part of the capacity it offers to satisfy the limited must-offer test, provided those resources are available, properly registered, and offered in accordance with Attachment AE. However, the participant still bears congestion, curtailment, outage, and performance risks. These risks will be identified through the SCED model, which will adjust dispatch around transmission constraints. If any generation (ERIS or NRIS) is behind transmission constraints, the market will have them dispatched lower (assuming all other variables like fuel price, ramp rates, etc. being equal). The tariff requirement is an offer obligation, not a guarantee that the offered generation will be committed, dispatched, or deliverable to a particular load settlement location.

4 | ERS in Real-Time Operations and Curtailment Processes

In real-time operations, SPP manages the transmission system through security-constrained economic dispatch (SCED), operating-reserve deployment, reliability coordination, outage coordination, and emergency procedures. ERS resources are dispatchable market resources to the extent of their registered capabilities and offers, but they operate within the same physical network constraints that apply to the rest of the fleet. Said differently: **neither NRS nor ERS provides immunity from redispatch or curtailment.**

The most common reduction in output is economic or congestion-driven dispatch. When a transmission constraint binds, SPP's Real-Time Balancing Market adjusts resource setpoints based on shift factors, offers, operating limits, ramp rates, and reliability requirements. A generator that aggravates the constraint, regardless of interconnection service level, may receive a lower dispatch instruction, while a resource that relieves the constraint may be increased. For variable energy resources, such as wind, the dispatch instruction can require an output setting below the resource's available capability, producing what is commonly described as market "curtailment." Critically, **the Real-Time Balancing Market does not distinguish between NRS**

and ERS resources, and NRS resources may be dispatched down prior to ERS resources based on economics.

A day-ahead award does not eliminate this exposure. Deviations between the day-ahead schedule and real-time dispatch are settled in the Real-Time Balancing Market. Thus, an ERS resource may have a day-ahead energy award and still be required to reduce output in real time because of an unplanned outage, load or generation forecast error, a newly binding constraint, a change in topology, or a reliability event. The financial consequences depend on day-ahead and real-time prices, the resource's offers, applicable make-whole provisions, and the reason for the deviation.

4.1 Curtailment hierarchy and mechanisms

- **Security-constrained economic dispatch (SCED):** the normal market mechanism for managing congestion through resource setpoint instructions.
- **Reliability Unit Commitment and supplemental commitments:** additional units may be committed when day-ahead schedules are insufficient for forecast conditions or reliability

requirements, changing real-time congestion patterns and dispatch.

- **Manual reliability directives:** SPP may issue operating instructions outside normal market dispatch when needed to preserve reliability, including during transmission emergencies, communication failures, or conditions not adequately represented in the market model.
- **Transmission Loading Relief (TLR) and interchange curtailment:** NERC and interconnection-wide procedures may be used to reduce tagged transactions or manage constrained facilities when applicable.
- **Interconnection-agreement or limited-operation restrictions:** a generator may be capped below full output until required facilities are complete or when studies establish a temporary operating limit.
- **Emergency actions:** during Energy Emergency Alerts or other severe events, SPP may deploy reserves, request additional generation, curtail exports, shed non-firm obligations, or take other actions under applicable reliability procedures.

4.2 Does NRIS receive priority over ERIS in real time?

As a general matter, SPP's market engines do not dispatch a generator simply because it holds NRIS rather than ERIS. Market dispatch is based on economic offers and security constraints, not a standing interconnection-service priority stack. Likewise, neither ERIS nor NRIS is equivalent to firm transmission service. The physical effect of network upgrades

funded for NRIS may reduce the likelihood or severity of certain constraints, but it does not create a categorical operational exemption from congestion or curtailment.

The relevant priority rules depend on the specific mechanism being used. Market re-dispatch for all resources, regardless of ERIS or NRIS, follows the Integrated Marketplace rules. Curtailment of interchange transactions may consider transmission-service priority and NERC procedures. Emergency directives follow reliability authority and tariff provisions. An ERIS generator's commercial arrangement, transmission reservation, resource-adequacy designation, or bilateral contract may affect settlements and obligations, but those instruments do not override SPP's authority to dispatch or curtail resources to maintain system reliability.

Market dispatch is based on economic offers and security constraints, not a standing interconnection-service priority stack. Likewise, neither ERIS nor NRIS is equivalent to firm transmission service. The physical effect of network upgrades funded for NRIS may reduce the likelihood or severity of certain constraints, but it does not create a categorical operational exemption from congestion or curtailment.

4.3 Reliability challenges in operations and lessons learned

SPP has operated an energy imbalance market since 2007 and the Integrated Marketplace since March of 2014. The energy imbalance market was a five-minute real-time as available market that was solved by SCED.



The energy imbalance market maintained 15 separate balancing authorities while the Integrated Marketplace consolidated all of those BA's into one area operated by SPP.

One of the early reliability challenges SPP faced was from ERIS resources that were contributing energy but not controllable by the region. During periods of high wind, for example, congestion would occur and SPP market rules did not allow it to reduce certain generation that was providing energy on the grid. This limitation of generation movement made congestion management more difficult. **SPP market rules have changed and currently all generation registered in the market is managed and controllable.** The SPP BA operational control over all the market generation is generally very effective at maintaining a reliable grid using the most economic generation available. Variable resources, such as wind contribution to serving SPP load ranges from nearly 90% to almost zero while maintaining reliable operations.



5 | ERIS and Energy-Only Interconnection in Other Markets

FERC Order No. 2003 established ERIS and NRIS as pro forma interconnection-service concepts, but organized markets have adapted the relationship among interconnection, deliverability, capacity qualification, and transmission service in different ways. The terminology is not uniform. Some regions retain ERIS and NRIS; others use an energy-only versus deliverable or capacity designation. The common policy issue is whether a generator has merely demonstrated that it can interconnect reliably or has also demonstrated that its output is deliverable for capacity or load-serving purposes.

5.1 Midcontinent Independent System Operator

MISO retains ERIS and NRIS. NRIS is generally treated as deliverable for converting accredited capacity into zonal capacity credits, while ERIS capacity may require firm trans-

mission service or other deliverability support. MISO's real-time operations are similar to SPP's in that ERIS and NRIS are not differentiated in market dispatch. Both markets are focused on a security-constrained economic dispatch of all on-line available generation, regardless of interconnection service level.

5.2 PJM Interconnection

PJM distinguishes energy-only resources from capacity resources through Capacity Interconnection Rights and related capacity-market requirements. An energy resource can interconnect and participate in energy markets without obtaining the deliverability rights needed to offer the same output as capacity in the Reliability Pricing Model. PJM's real-time operation is mostly the same as SPP in that energy and capacity resources compete in SCED without a general priority based on capacity status.

Conclusion

ERIS provides a more flexible pathway for many generators to connect and compete in energy markets, but it is only one layer of the framework. Reliable and commercially durable use of ERIS generation depends on the transmission network, market dispatch, resource-adequacy rules, contractual arrangements, and real-time operating conditions that surround the interconnection right. Regional markets, such as SPP, use ERIS resources in real-time as a key energy contributor to maintaining a secure electric grid, but these resources are supported by a robust regionally planned bulk transmission system to support all of SPPs members.

ERIS should be understood as a reliable interconnection and conditional injection right. It is not a substitute for regional transmission planning, firm transmission service, capacity qualification, or real-time congestion management.

About the Author

Bruce Rew is the Principal of REW Power Strategies, LLC, a consulting firm focused on electric-industry strategy, regional transmission organizations, wholesale energy markets, transmission planning, grid operations, generation interconnection, and the application of artificial intelligence to power-system decision-making.

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