Data Centers Drive Interconnection and Governance Fights

August 22-28, 2026

Executive Summary

The week ending August 28 was operationally uneventful across nearly every North American market—no heat emergencies, demand records, or scarcity intervals surfaced in the reporting window—but it was among the busiest weeks of the summer for the policy fights that will shape prices for years. A single theme tied the continent together: the interconnection and cost-allocation strain created by large data-center load. In ERCOT, Governor Greg Abbott's demand for an audit of roughly 300 data-center projects put the market's "Batch Zero" interconnection process on a compressed December timeline against a queue that has swelled to some 474 GW. In PJM, consumer advocates from six states and the District of Columbia asked FERC to reject the Reliability Backstop Procurement, warning that its roughly $20 billion budget and elevated $555/MW-day cap would shift data-center-driven costs onto residential ratepayers. In Alberta, fresh analysis warned that connecting Meta's planned load could raise consumer bills. The common question everywhere was not whether the load is coming, but who pays to serve it.

Alongside the data-center reckoning, the week delivered a heavy slate of transmission-planning and governance developments. MISO opened a South Long-Range Transmission Plan after finding that load pockets in Louisiana no longer meet the one-day-in-ten-years reliability standard, while accepting a roughly $240 million cost increase on a Minnesota 345-kV line already in its portfolio. New England transmission owners disclosed a five-year rate forecast climbing about a third by 2031, and National Grid proposed a $1.2 billion rebuild across Massachusetts and Vermont. On the Western seams, the Extended Day-Ahead Market cleared a governance hurdle as the WEM Governing Body tied its charter-review obligation to the West-Wide Governance Pathways Initiative, and Portland General Electric confirmed it remains on track to join EDAM on October 1 despite settlement-software errors the operator is still correcting. Beneath the quiet grid, in short, the market design of the next decade was being negotiated in filings, workshops, and committee rooms.

CAISO

CAISO operations were calm through the reporting week, with no Flex Alert, restricted maintenance operation, or energy-emergency notice issued between August 22 and 28 and no verifiable in-window price spike or demand record on the California grid. The operator's attention was largely administrative and forward-looking: it posted the Extended Day-Ahead Market access charge rates effective May 1, 2026 on August 27, issued its scheduling-coordinator self-audit attestation notice with a November 2 deadline, and refreshed its public interconnection queue report. Registration also opened on August 25 for the Joint Market Seams Workshop scheduled for September 16, an increasingly consequential venue as CAISO's day-ahead market and SPP's competing Western offering move toward a shared border.

On the planning side, CAISO scheduled its 2026–2027 Transmission Planning Process stakeholder meetings for September 23 and 24 and continued to build out the procedural scaffolding for its interconnection reforms, publishing a sample cluster deliverability-eligibility application and updated new-resource implementation guidance. Stakeholder activity was routine but steady, including a Settlement User Group session on August 26, a Congestion Revenue Rights Customer Partnership Group meeting on August 25, and a Business Practice Manual change-management session the same day. With no operational drama to report, the CAISO story this week was one of quiet groundwork—rate mechanics, audit compliance, and the transmission and seams processes that will define the year ahead rather than the week just passed.

WEIM/EDAM

The Western regional markets carried the week's most substantive news. On August 24 the WEM Governing Body voted unanimously to treat its charter obligation for a periodic governance review as satisfied by its ongoing participation in the West-Wide Governance Pathways Initiative, formally linking EDAM and WEIM governance to the broader transition toward an independent Western market operator rather than launching a separate review. The same day, CAISO released its monthly EDAM performance report for July, which showed a 100 percent resource-sufficiency passing rate across the three participating balancing areas—CAISO, PacifiCorp East, and PacifiCorp West—and intertie exports sourced from the CAISO area reaching as much as roughly 8,000 MW on peak-demand days. Day-ahead results were published before 1:00 p.m. on 55 percent of July days, and price convergence between day-ahead and real-time generally tracked closely, though the Six Cities group commented that EDAM's economic benefits "remain uncertain."

Attention also turned to the market's next entrant. Portland General Electric remains on track to join EDAM on October 1, even as CAISO works to correct settlement-software errors identified in the new day-ahead market, and four additional entities are reportedly weighing entry in 2027. The trajectory underscores EDAM's momentum as the anchor of a consolidating Western day-ahead footprint, while the settlement issues are a reminder that a market still early in its operational life is being scaled quickly. Together with the governance decision, the week reinforced that the West's market-design contest is advancing on two fronts at once: expanding participation and building the durable institutional structure to govern it.

ERCOT

ERCOT absorbed a late-August heat run without incident, with demand peaking near 90,350 MW on August 20—just below the all-time record of 91,089 MW set on July 22—as solar and battery output covered the evening ramp despite forecasts of sagging wind. No conservation appeals or emergency conditions were declared during the window, and real-time prices stayed well below the offer cap. The operational quiet, however, was overshadowed by the policy story that has consumed the Texas market: Governor Abbott's early-August directive for an audit of the data-center projects flooding the interconnection queue. During the reporting week ERCOT was working against a compressed timeline, targeting completion around December 10 with a report to the Public Utility Commission of Texas roughly a week earlier.

The audit's scope is sweeping. It covers on the order of 300 data centers of at least 75 MW moving through the "Batch Zero" interconnection process, adds community-impact reviews for facilities of 25 MW and larger, and unfolds against an interconnection queue cited at roughly 474 GW—some 90 percent of it large load. Requests for information were slated to go out from late August through September, with additional rounds anticipated into the fall, and the timing has raised concern that Batch Zero's own schedule could slip as the review proceeds. For a market that has staked its growth narrative on attracting hyperscale load, the week crystallized the central tension between moving quickly to connect that load and satisfying a new political mandate to scrutinize its cost, siting, and reliability implications before the interconnection floodgates open further.

SPP

SPP's week was defined by a cluster of routine but consequential filings at FERC and by working-group activity on its generator-interconnection process. Between August 21 and 24 the operator submitted a batch of Section 205 revisions, including changes to its CHILL policy to accommodate planned outages, modifications to Attachment AE to improve co-located resource functionality, a new affiliate-designation registration requirement, and—most notably—a proposal to establish electromagnetic-transient study requirements in the interconnection process, with an effective date of October 24. Operationally the footprint was quiet, well off the 57.9 GW all-time summer peak the pool set in late July, with no in-window scarcity or congestion event of note.

The interconnection theme carried into SPP's Generator Interconnection Advisory Group, which met on August 24 to work through the transition from its legacy agreements to the new Consolidated Planning Process framework and a "limited operation" construct that drew dissent from several utilities. The group also took up a storage reliability and flexibility initiative and, significantly, discussed affected-system coordination with MISO following the late-July D.C. Circuit decision upholding FERC's Order 2023, which will require SPP to evaluate neighboring requests on energy-resource rather than network-resource interconnection criteria. The electromagnetic-transient study filing at FERC is the regulatory counterpart to this stakeholder work, and together they signal that SPP's interconnection queue—like its peers'—is being re-engineered to handle a heavier and more technically complex pipeline of resources.

SPP Markets+

SPP's Markets+ offering saw no concrete milestone during the reporting week—no new FERC tariff filing, no newly executed implementation or funding agreement, and no additional committed entity—leaving the seven-day window thin on transactional developments. The Phase 2 implementation and its governance and funding arrangements, all secured earlier in the cycle, continued to advance in the background toward a phased go-live targeted across 2027 and 2028, but produced nothing new to report between August 22 and 28. What did surface was atmospheric rather than structural, centered on the still-unresolved question of which Western utilities will ultimately choose Markets+ over the competing Extended Day-Ahead Market.

Two developments late in the week captured that positioning. Reports indicated the Bonneville Power Administration intends to issue further clarification on its day-ahead market options, with new Administrator Travis Kavulla expected to explain in the coming months how he is evaluating the choice—a signal that BPA's prior lean toward Markets+ may be revisited under new leadership. Separately, advocacy groups pressed Arizona regulators to exercise greater oversight and transparency over how utilities in that state select a day-ahead market, relevant because several major Arizona utilities have committed to Markets+. Neither item changed the ledger of signed participants, but both underscored that the Western market-seam contest remains fluid and politically charged as the decision windows for large utilities approach.

MISO

MISO's week was dominated by transmission planning and resource-adequacy debates rather than market operations, which stayed quiet as Great Lakes weather moderated and late-August loads fell short of July's sustained highs. The headline came on August 27, when the operator used its Planning Advisory Committee to launch a South Long-Range Transmission Plan after finding that load pockets in Louisiana—including Amite South and the Downstream of Gypsy area—no longer meet the one-day-in-ten-years reliability standard and face widening capacity shortfalls by 2030 despite planned additions. Days earlier, the operator accepted a roughly $240 million cost increase, about 25 percent, on the Iron Range–Benton County–Big Oaks 345-kV line in Minnesota, having trimmed the developers' larger requested escalation after a reevaluation.

Resource adequacy provided the week's other throughline. MISO disclosed that it had leaned on nearly 18 GW of import assistance during the mid-July maximum-generation emergency—its largest-ever such record—and its first load-modifying-resource unavailability investigation, tied to the January winter storm, opened a pointed debate over accountability when demand-response-enrolled businesses simply close their doors. The operator also advanced proposals through its Resource Adequacy Subcommittee to penalize generators that intentionally stretch unit lead times as emergencies approach, another lesson drawn from January. Rounding out the week, Owensboro Municipal Utilities in western Kentucky moved to join the footprint as a load-serving entity. Taken together, the developments show a market simultaneously planning for long-run load growth and tightening the rules that govern how resources must perform when the grid is stressed.

PJM

PJM's reporting week was consumed by the fight over how to procure capacity for a data-center-driven load surge without saddling ordinary customers with the bill. On August 26, ratepayer and consumer advocates from six states and the District of Columbia—including the Maryland Office of People's Counsel, the Ohio Consumers' Counsel, and the Pennsylvania Office of Consumer Advocate—urged FERC to reject PJM's Reliability Backstop Procurement, arguing it unfairly burdens the public with costs driven by large new loads. The mechanism, whose auction window runs from September 30 to October 21 with results due by early December, carries a budget of as much as roughly $20 billion and a price cap raised to $555/MW-day from $325, and is intended to address the 6.8 GW shortfall left by the last capacity auction for mid-2028 delivery.

The backstop was not the only front. FERC approved a two-year extension of the reliability-must-run agreements for the Baltimore-area Brandon Shores and H.A. Wagner units, keeping them online through 2031 past their planned deactivation, while PJM signaled it is considering consolidating generation and large-load interconnection into a single unified analysis in response to a FERC show-cause order on co-located load. Governance drew scrutiny as well, with dozens of stakeholders filing post-technical-conference comments recommending sweeping changes to PJM's Board of Managers and stakeholder process. Underneath the policy churn, state politics sharpened:

New Jersey municipalities including Jersey City moved to restrict data-center development beyond state limits, exposing a widening gap between local resistance and the interconnection pipeline PJM must plan around.

ISONE

ISO-NE had a moderately active week centered on transmission and cost allocation rather than operations, with no in-window heat event or price record to report as the Northeast's major 2026 heat spells receded into early summer. On the regulatory front, FERC denied a complaint from the Maine Office of the Public Advocate contesting the prudence of the region's asset-condition project spending, finding the advocate had failed to raise serious doubt about the disputed investments—a ruling that feeds into the operator's broader effort to reform how asset-condition work is reviewed. The decision landed as the cost of the region's aging transmission fleet moved to the center of stakeholder attention.

That attention was sharpened at the Planning Advisory Committee, where New England transmission owners detailed a five-year rate forecast showing the Regional Network Service rate climbing from about $177.63 per kilowatt-year in 2026 to roughly $237 by 2031, an increase of about a third driven largely by capital spending. National Grid proposed a roughly $1.2 billion rebuild of two lines across northern Massachusetts and southern Vermont, upgrading them from 230-kV to 345-kV toward the New York border, while a multi-state Northern Maine procurement preliminarily selected a 1,200-MW transmission line and an 800-MW onshore wind project developed in coordination with four other New England states. The week's message was consistent: New England's transmission bill is rising quickly, and the projects and rate impacts that drive it are now front and center for both regulators and consumer advocates.

NYISO

NYISO had a thin reporting week, with no verifiable in-window operational or price event and the region's notable summer demand tied to the July heat wave rather than the days in question. The single concrete development came on August 24, when the operator's Operating Committee approved its 2024 Interconnection Cluster Study—but not without friction, as generators and environmental interests, including the Alliance for Clean Energy New York, challenged the transparency of National Grid's network-upgrade cost analyses ahead of the vote. The dispute reflects a recurring tension in New York's cluster-study framework between moving projects forward and giving developers confidence in the cost estimates that determine which projects survive.

Beyond the cluster study, the week produced little in the way of fresh state policy or capacity-market action, with no in-window Public Service Commission or FERC order specific to the New York market and no ICAP auction milestone. A widely circulated retrospective feature on the strain that recurring heat waves place on New York's grid drew on 2025 data and structural reliability concerns rather than any event within the window, underscoring the longer-run adequacy questions facing a system in transition. For a market whose defining challenges—interconnection throughput, transmission buildout, and the reliability of a rapidly changing resource mix—are structural rather than weekly, the cluster-study approval and its accompanying cost dispute were a fitting encapsulation of a quiet but telling week.

AESO

Alberta's market saw a thin week for verifiable developments, with no stakeholder or board sessions held between August 22 and 28 and no confirmable in-window pool-price anomaly or supply-cushion event in the public record. The one clear in-window item was a policy analysis warning that connecting Meta's large planned data-center load to the Alberta grid could put upward pressure on consumer electricity bills—an argument that lands squarely within the province's intensifying debate over how to integrate hyperscale demand and who should bear the associated system costs. The item echoes the same data-center cost-allocation question playing out in ERCOT and PJM, now surfacing in a distinctly Albertan regulatory and political context.

Beneath the quiet week, the province's Restructured Energy Market transition continued to advance without producing an in-window milestone, with the next substantive touchpoints—including a locational marginal pricing session and a REM implementation and market-readiness update—scheduled for September. The Alberta Electric System Operator's engagement calendar showed no events during the reporting window, bracketed by a base-rate session shortly before and a cluster of feedback deadlines and workshops shortly after. For a market in the midst of one of the most consequential redesigns in North America, the week was a pause between chapters rather than a development in its own right, with the fall's calendar poised to carry the substance the window itself lacked.

IESO

Ontario's market was quiet operationally but produced two concrete market-design and transmission items during the week. On August 24, the IESO advanced a market-rule amendment to correct inaccurate real-time make-whole payments arising from derates at combined-cycle plants modeled as pseudo-units, closing a gap that had led to overpayments—a technical but meaningful fix as the operator refines the settlement mechanics of its renewed market. No in-window price anomaly or demand record surfaced, with Ontario's hourly pricing operating without a flagged disruption over the seven days.

The week's more strategic item concerned the roughly 900-MW Toronto Third Line, a proposed subsea high-voltage direct-current link running beneath Lake Ontario from Bowmanville into downtown Toronto. The IESO is developing a commercial procurement framework that would shift more cost risk onto the winning developer for factors it can reasonably control, while allowing adjustments for those it cannot—an approach that signals how the operator intends to allocate risk on the large, complex transmission projects Ontario's load growth will increasingly demand. Together, the make-whole correction and the Third Line framework capture an IESO working simultaneously on the fine detail of market settlements and the high-stakes structure of its next major transmission build.

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