Large-Load Rules Reach FERC as the West Realigns Its Governance

October 24-30, 2026

Executive Summary

North American wholesale power markets settled into a quiet late-October shoulder-season pattern during the week of October 24-30, with mild, well-supplied conditions across the continent and no system-wide emergencies, demand records, or sustained scarcity events reported in any footprint. Day-ahead on-peak prices for the October 28 trade date reflected that calm, clearing in the roughly $42 to $70 per megawatt-hour range in the eastern organized markets and near $25 to $55 across the West and Northeast, with the sharpest news flow coming from regulatory and governance matters rather than operations. The one consistent operational thread was the continued normalization of load and price after the extreme-heat and maintenance-driven volatility that had gripped PJM and MISO earlier in October, which by this window had receded entirely.

The week's defining story was the coordinated, parallel response by grid operators to the Federal Energy Regulatory Commission's June 2026 show-cause order on large-load interconnection. CAISO's Board of Governors approved a formal large-load framework on October 28, setting a 50-megawatt threshold and a flexible interim connection option ahead of a tariff filing due at FERC by November 16, while SPP said it was roughly ninety percent compliant with the same order and New York's transmission owners moved to file their own cost-recovery agreement under Section 205. Running alongside was a decisive week for Western market governance, as the newly seated Regional Organization for Western Energy solicited input on a headquarters location and a Ninth Circuit decision was read by observers as clearing BPA's path to reconsider SPP Markets+ in favor of CAISO's Extended Day-Ahead Market. In the East, PJM prepared to refile its Reliability Backstop Procurement with FERC and MISO advanced a record 2027 budget, external-resource accreditation work, and the quiet conclusion of a failed joint study with SPP.

CAISO

CAISO operated throughout the week without a publicly reported system-wide emergency, exhibiting a conventional autumn price profile as mild temperatures and ample supply kept the grid comfortably balanced. Next-day on-peak energy at the SP15 hub cleared near $27 per megawatt-hour for the October 26 delivery date, a low shoulder-season level, and the daily market produced no scarcity signals, records, or notable congestion events. With solar still contributing meaningfully to midday supply, the familiar late-afternoon net-load ramp remained the principal source of intraday price formation, but the magnitude of those movements was modest relative to the summer peak season.

The week's central development was the Board of Governors' October 28 approval of a new framework for interconnecting large loads, CAISO's formal answer to FERC's June 2026 show-cause order directed at all six organized markets. The framework defines a large load as a single end-use site of at least 50 megawatts, declining a request from Pacific Gas and Electric to set the threshold at 20 megawatts, and pairs that definition with a single flexible interim option that allows qualifying loads to connect before network upgrades are complete, subject to curtailment, telemetry, hourly forecasting, and the operator's ability to remotely disconnect for reliability. Transmission owners would study such loads on a 60-to-90-day cycle, and CAISO must submit the implementing tariff to FERC by November 16, a timeline sharpened by state forecasts that data-center demand could reach 1.8 gigawatts by 2030 and 4.7

gigawatts by 2035. CAISO notably declined requests from California regulators and utilities to become a party to the underlying cost-recovery agreements.

WEIM/EDAM

The Western Energy Imbalance Market and the Extended Day-Ahead Market continued to supply broad real-time and day-ahead coordination across the West without disruption during the week, with their daily reports remaining the principal public window into regional prices, transfers, congestion, and resource-sufficiency outcomes. No new balancing authority went live in either market inside the reporting window, leaving operations to follow the same afternoon net-load ramps, regional transfer economics, and localized constraints that have characterized the autumn season. Because EDAM is a day-ahead construct, the week's real-time price signal continued to originate in WEIM and participating balancing-area prices, while day-ahead values reflected next-day commitment and transfer conditions rather than any acute system stress.

Governance and footprint questions dominated the week's EDAM-related news. The newly seated Regional Organization for Western Energy, the independent body created through the West-Wide Governance Pathways Initiative to assume governance of CAISO's western markets, formally solicited stakeholder input on October 28 regarding where to site its headquarters, with Portland among the cities under consideration, even as it moved quickly to appoint a chief executive. The window also brought commentary that a Ninth Circuit decision dismissing a challenge to BPA's market choice could open the door for Bonneville to reconsider EDAM participation, a potentially significant shift in the Western footprint, while Portland General Electric publicly pushed back on conditions its state regulator attached to a proposed corporate reorganization. Taken together, the week reinforced that the Western market's most consequential developments are now institutional and jurisdictional rather than operational.

ERCOT

ERCOT's public operations messaging indicated no system-wide energy emergency during the week, with mild and at times rainy weather leaving the grid well-supplied and prices subdued. Peak demand reached roughly 63,400 megawatts on October 28, modestly above the day-ahead forecast and near the upper portion of the trailing five-year range for the date, while the October 26 peak came in near 60,000 megawatts, slightly below forecast; hub-average real-time prices stayed low, touching only around $31 per megawatt-hour at the morning ramp on October 26. Weekly average load rose to roughly 53 gigawatts from about 50 gigawatts the prior week, and the fleet remained comfortable even with Comanche Peak Unit 1 offline for a refueling outage, a far cry from the all-time peak of more than 91,000 megawatts set in late July.

The week's most substantive ERCOT-adjacent development came from American Electric Power's October 28 third-quarter earnings call, which detailed a five-year capital plan of roughly $100 billion and, within Texas, a $17 billion AEP Texas program anchored by the Howard-to-Solstice 765-kilovolt line and supported by some 46 gigawatts of large-load agreements structured to comply with the state's new Senate Bill 6 interconnection requirements. The disclosures underscored the scale of data-center and industrial demand pressing on the Texas grid even as the state's broader interconnection process remained in a cautious posture, with the governor's pause on certain large-load connections still in effect and ERCOT's data-center audit report to the Public Utility Commission due in December. No ERCOT board or Public Utility Commission open meeting fell within the reporting window, leaving the earnings disclosures and the ongoing large-load policy backdrop as the week's main threads.

SPP

SPP's Integrated Marketplace operated without a publicly identified region-wide emergency during the week, and the autumn shoulder season produced no notable scarcity, price records, or widespread congestion that could be confirmed in public reporting. Verifiable in-window operational and price detail for the footprint was limited, consistent with a mild, well-supplied period in which day-ahead and real-time outcomes tracked ordinary seasonal patterns. The absence of acute operational news left the week's SPP story to regulatory, planning, and interregional matters rather than to the energy market itself.

SPP stated on October 25 that it was approximately ninety percent compliant with FERC's show-cause order on large-load interconnection, crediting a new participation model designed to accommodate flexible and price-sensitive loads, a posture that places it alongside the other organized markets racing to satisfy the Commission's June directive. The week also closed out SPP's two-year interregional study with MISO without a recommended project, as the two operators declined to advance the anticipated 500-kilovolt Oklahoma-to-Arkansas line, a disappointing result for advocates of seams-spanning transmission even as each footprint continues to pursue aggressive internal expansion. These developments kept SPP's

focus on the interface between accelerating load growth, interconnection reform, and the transmission build-out needed to serve it.

SPP Markets+

SPP Markets+ remained in its pre-launch implementation phase during the week and therefore produced no live daily real-time price signal, leaving its news flow entirely to legal, governance, and seams matters. The dominant development was the reading, circulated October 27, that a split Ninth Circuit panel's dismissal of a challenge to Bonneville Power Administration's earlier decision to join Markets+, resolved on standing grounds because the market does not yet exist, had the practical effect of freeing BPA to revisit that choice in favor of CAISO's Extended Day-Ahead Market. Because Bonneville's participation is central to the scale and viability of the Markets+ Western footprint, any such reconsideration represents a material risk to the initiative's trajectory and was the week's single most consequential Markets+ item.

On the seams front, a fourth joint CAISO-SPP workshop introduced a new coordination tool, described as Western Interconnect Loading Relief, intended to manage congestion across the boundary between the two operators' western markets, with education expected to continue into 2027 as the parties work toward a joint operating agreement. Governance questions among Markets+ participants, including the balance of voting rights between investor-owned and public-power interests that independents have sought to protect, remained unresolved, and no Markets+ Independent Panel or related governance meeting could be confirmed within the reporting window. The net picture for Markets+ was one of a market still being assembled against a backdrop of unsettled participation and governance.

MISO

MISO's market operated throughout the week without a widely reported system-wide emergency, a marked contrast to the extreme-heat and maintenance-driven volatility of mid-October, which had briefly pushed day-ahead prices toward four figures but had fully subsided by this window. Day-ahead on-peak energy in the Illinois hub region cleared near $43 per megawatt-hour for the October 28 trade date, a normalized shoulder-season level, with mild conditions across the footprint and no scarcity or record demand to report. The quieting of operations shifted attention squarely onto the market's active policy, budget, and planning agenda.

The week was dense with MISO policy activity. The operator advanced a proposed 2027 budget of roughly $550 million, its largest ever, attributed in substantial part to interest refunds owed to interconnection customers exiting the queue, and continued developing a single accreditation method for external capacity resources that would account for high-voltage direct-current-enabled imports such as the Grain Belt Express. Members of the Advisory Committee broadly criticized the Department of Energy's emergency orders compelling several coal units to keep operating past their planned retirements, and the Organization of MISO States convened its annual meeting on October 27, where current and former regulators floated reviving a multi-state platform with SPP to advance interregional planning, a timely theme given the two operators' failure that same week to identify a joint transmission project.

PJM

PJM began the reporting period having fully emerged from the prior week's extreme-heat event, with demand and prices returned to seasonal norms under mild, well-supplied conditions and no system-wide emergency in effect. Day-ahead on-peak energy at the Western Hub cleared near $70 per megawatt-hour for the October 28 trade date, the highest among the major eastern hubs for the week but well short of the stressed levels seen earlier in the month, reflecting an orderly autumn operating pattern once the heat and generator maintenance that had tightened conditions in mid-October passed. The calm on the operational side allowed capacity-market and governance questions to dominate the week.

PJM indicated it would refile its Reliability Backstop Procurement mechanism with FERC on October 29, responding to the Commission's late-September order that had accepted and suspended the proposal while requiring changes to cost allocation, transmission-owner exit provisions, and load-serving-entity collateral requirements as the underlying hearing proceeds. The refiling landed amid intensifying debate over who should govern the market: at the annual meeting of the Organization of PJM States, regulators amplified calls for a greater state role as PJM prepares a separate FERC filing on its decision-making structure, while a clean-energy advocate publicly warned that the operator's large-load interconnection plan risks shifting cost and timing risk onto generation developers. The week thus captured PJM at the intersection of capacity adequacy, large-load accommodation, and a contested governance model.

ISONE

ISO New England's public operations reporting showed a normal autumn operating pattern through the week, with no system-wide emergency and shoulder-season loads that left the system comfortably within its resources. Day-ahead on-peak energy at the Massachusetts hub cleared near $55 per megawatt-hour for the October 28 trade date, a moderate level consistent with mild conditions, while planned outages on the Cross Sound Cable and the Phase II interconnection with Hydro-Quebec persisted through the window without creating operational difficulty. The region's reported margins reflected routine scheduled maintenance rather than any genuine shortfall.

Transmission and capacity-market administration provided the week's substantive developments. New England's transmission owners disclosed roughly $1.8 billion in additional asset-condition projects to the Planning Advisory Committee, a continued escalation of the reinvestment needed to maintain the aging regional network, building on the asset-condition review process FERC had approved shortly before the window. On the market-design side, the operator posted self-paced training on resource-deactivation procedures under its capacity auction reforms, an incremental step in the transition toward a prompt, seasonal capacity construct. With no NEPOOL Participants Committee, Markets Committee, or Reliability Committee meeting scheduled during the window, the week's activity was administrative rather than deliberative.

NYISO

NYISO's market operated through the week without a reported system-wide emergency, following a routine autumn pattern of mild weather and comfortable supply. Day-ahead on-peak energy in the lower-Hudson Zone G cleared near $49 per megawatt-hour for the October 28 trade date, a moderate shoulder-season level, and no demand records, scarcity events, or significant congestion could be confirmed for the footprint within the window. As elsewhere, the quiet operating backdrop placed the week's emphasis on interconnection policy.

The week's principal NYISO development was the move by New York's transmission owners to file their own large-load cost-recovery agreement at FERC under Section 205 of the Federal Power Act, electing to proceed separately rather than through a joint NYISO filing in an effort to avoid a jurisdictional clash between state authority and federal ratemaking. The step followed a period of lukewarm stakeholder support for the operator's broader large-load interconnection framework, in which several state agencies had expressed reservations, and it situates New York within the same continent-wide scramble to satisfy FERC's show-cause directive that shaped the week in CAISO, SPP, and the other markets. The operator's reliability planning continued in the background, with its latest resource-adequacy assessment expected to be finalized in the following weeks.

AESO

Alberta's market operated without a publicly reported system-wide emergency during the week, with pool prices sitting at low levels that reflected ample supply and moderate autumn demand. The two in-window days for which settled figures were available, October 24 and October 25, averaged roughly $24 and $30 per megawatt-hour in Canadian dollars respectively, consistent with a weekly average in the mid-$30s and a market free of supply-cushion alerts or emergencies; internal load averaged near 10,600 megawatts. Settled daily prices for the back half of the window had not yet been published as of the reporting date, so the operational read for October 26 through 30 remains preliminary, but nothing in the available data suggested stress.

On the regulatory side, the Alberta Utilities Commission clarified on October 26 that any generation or storage facility of at least one megawatt of total capability requires Commission approval regardless of how it is used, while offering a streamlined checklist for projects between one and ten megawatts, a clarification aimed at the proliferation of behind-the-fence and backup generation. The week also brought fresh evidence of the data-center surge testing the Alberta grid, with reporting that more than forty proposals representing on the order of 26 gigawatts have sought to connect, a pipeline the operator has been careful to note consists of applications rather than approvals. Underlying all of this, AESO continued its preparation for the Restructured Energy Market and associated rule development, though no specific implementation milestone fell within the window.

IESO

Ontario's renewed wholesale market continued normal operations throughout the week, with the day-ahead and real-time constructs introduced through the province's market renewal program functioning without reported incident. No in-window price records, demand peaks, or operational disruptions could be confirmed from public sources, consistent with a mild autumn period and a market operating within comfortable margins. The week was, on the operational side, uneventful for the province.

IESO's policy and stakeholder activity was notably quiet within the reporting window, with no major procurement milestone, capacity-auction event, or governance decision date-confirmed between October 24 and 30; the province's active resource-adequacy agenda, including its medium- and long-term procurement streams and the capacity auction cycle, had its most recent milestones fall just before the window and its next steps scheduled beyond it. The organization's strategic focus remained on securing new supply to meet forecast demand growth and on advancing transmission and generation, including the province's nuclear refurbishment and small modular reactor programs, but the week itself produced little verifiable news. Ontario's near-term challenge continues to be sustaining momentum in resource acquisition while the renewed market matures.

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