Large-Load Policy Comes to a Head Amid a Transmission Buildout

October 17-23, 2026

Executive Summary

North American wholesale power markets passed a quiet operational week, with mild shoulder-season conditions prevailing across every region and no heat event, cold snap, or scarcity pricing of note in any footprint. Real-time prices were soft and unremarkable from Texas to the Northeast, and the Western heat spell that had briefly lifted prices earlier in October had fully receded by the reporting period. With the grid itself calm, attention turned almost entirely to policy, and the dominant storyline of the week was the accelerating reckoning over large loads and data centers. FERC convened a high-profile technical conference on reliability and large loads on October 21, and the fallout from the Commission's recent rejection of PJM's interim large-load service plan rippled through consumer advocacy, state politics, and even presidential commentary, while New York and New England grid operators struggled to win stakeholder consensus on their own large-load interconnection frameworks.

The second defining theme of the week was structural investment in the transmission system. SPP stakeholders endorsed a roughly $23.7 billion integrated transmission plan on October 19, a dramatic step up from the prior cycle, and SPP and MISO jointly reported that their seams transmission portfolio had become fully subscribed. In the West, the Extended Day-Ahead Market marked six months of operation with PacifiCorp declaring the market working as intended, and Deseret Power won conditional FERC clearance to participate in both EDAM and SPP's expanding Western RTO. Corporate and state activity rounded out the week, led by intensifying scrutiny of the proposed $67 billion Dominion-NextEra combination in Virginia, where the governor and regulatory staff pressed for sweeping ratepayer conditions. Taken together, the week showed a sector managing abundant near-term supply while wrestling with the longer-term strain that data-center load growth is placing on markets, reliability rules, and transmission planning.

CAISO

CAISO operated throughout the week without a publicly reported system-wide emergency, and real-time conditions were mild and bearish as the early-October Western heat event faded into the background. Day-ahead and real-time prices settled into a modest shoulder-season range, with NP15 clearing in the high-$40s per megawatt-hour and SP15 generally in the high-$30s to low-$40s, and intraday peaks held well below summer levels. Battery storage again featured prominently in the daily dispatch, with the fleet charging through midday solar abundance and discharging across the evening ramp, reinforcing the pattern that has made storage a routine price-setting resource in California. In short, the operational story was one of comfortable margins and soft prices rather than stress.

Implementation and governance activity was the more substantive thread. On October 22 the CPUC Energy Division held a busbar mapping webinar on the resource portfolios feeding CAISO's 2027-2028 transmission planning process, CAISO conducted training on day-ahead market enhancement transitional measures, and the fourth CAISO-SPP joint market seams workshop examined Western relief processes and the enhanced curtailment calculator. Data-center load remained a live concern: the California Energy Commission approved additional funding for virtual power plant projects intended to offset growing AI data-center demand, and a PG&E agreement to serve a new 250-megawatt load in San Jose, tied to a Google facility, was queued for a late-October CPUC vote with added

ratepayer protections. CAISO also continued its Order No. 1920 regional transmission compliance work during the period.

WEIM/EDAM

The Extended Day-Ahead Market reached a notable milestone as it passed six months since its May 1 launch, and PacifiCorp publicly characterized the market as working well, reporting that early operational issues had largely been resolved and that gas-fired exports had reached new highs under the day-ahead construct. The companion Western Energy Imbalance Market continued to provide real-time coordination across the broader Western footprint without disruption. Verifiable in-window settlement statistics for the EDAM and WEIM footprints were limited, and consistent with the mild conditions across the West, pricing and dispatch were quiet rather than eventful during the reporting period.

Expansion of the Western market footprint was the clearer development. On October 19, FERC conditionally accepted a change-in-status filing from Deseret Power Electric Cooperative, clearing the Utah generation-and-transmission cooperative to participate in both CAISO's EDAM and SPP's expanding Western RTO, pending compliance. The seams between the Western day-ahead markets drew attention as well, with the October 22 CAISO-SPP joint workshop addressing coordination across the EDAM and Markets-plus boundaries. The cumulative effect was a footprint that continued to mature and broaden even in an operationally uneventful week, as prospective entrants weighed their day-ahead market options across the Western Interconnection.

ERCOT

ERCOT had a decidedly quiet, shoulder-season week, with no system-wide energy emergency, conservation appeal, or scarcity pricing at any point in the period. Real-time prices were very low across the grid; hub-average real-time settlement prices sat in the low teens of dollars per megawatt-hour, with individual hubs frequently in the single digits and even the firmer load zones rarely pushing far above the mid-$20s. Operationally, ERCOT's public market notices reflected only routine business, including daily reports of no sudden large generation losses and scheduled DC-tie maintenance, apart from a brief forced outage on a northern DC tie on October 21 that was cancelled the same day. Abundant supply and mild demand left the Texas grid comfortable throughout.

Regulatory and institutional activity was correspondingly thin inside the window. No Public Utility Commission of Texas open meeting fell within the period, with the adjacent meetings bracketing it in mid-October and early November, and the ERCOT board did not convene during the week. The most recent operational data release, ERCOT's monthly operational overview for September, was published just before the window opened and so sits outside the reporting period. In candor, ERCOT produced little verifiable in-window news beyond its calm operations; the week was most notable in Texas for the absence of the market stress that has defined so many recent autumns, a reflection of the continued build-out of generation and storage across the interconnection.

SPP

SPP's Integrated Marketplace operated without any publicly identified region-wide emergency during the week, and with mild conditions across the central United States, real-time prices were unremarkable. The operational calm, however, stood in contrast to an unusually active week on the planning and expansion fronts, where SPP advanced several of the most consequential structural initiatives in its recent history. The footprint's attention was fixed less on daily dispatch than on the long-term shape of the transmission system and the geographic reach of the organized market itself.

On October 19, SPP stakeholders endorsed an integrated transmission plan portfolio valued at roughly $23.7 billion, a striking escalation from the far smaller plan approved in the prior cycle and a signal of the scale of investment now seen as necessary to accommodate load growth and shifting resource mixes. On October 22, SPP and MISO jointly reported that their seams transmission portfolio of five 345-kilovolt projects had become fully subscribed, clearing a path for construction of long-planned interregional upgrades. Expansion of the organized market also advanced as Deseret Power was cleared to participate in SPP's growing Western RTO. Together these developments made SPP one of the busiest footprints of the week despite its quiet markets.

SPP Markets+

SPP Markets-plus remained in its implementation phase ahead of an anticipated 2027 launch and therefore had no live daily real-time prices to report during the week. Candidly, there was little verifiable Markets-plus-specific activity dated inside the window itself; the notable momentum for the Western day-ahead offering, including public support from the Bonneville Power Administration and Arizona utilities and a joint market-selection effort by two other Western entities, clustered in the days immediately preceding the reporting period rather than

within it. The initiative's trajectory thus continued largely on the strength of commitments already in motion.

The broader Western regulatory backdrop against which Markets-plus is being built did see movement, as FERC for a second time rejected a cost-recovery request tied to the Centralia coal facility while leaving the door open to a revised filing, an action bearing on the Western footprint that both Markets-plus and SPP's Western RTO are designed to serve. The core development question for Markets-plus remained one of participant commitments and tariff implementation rather than live market results, and with no new in-window milestone surfacing, the offering's status is best described as steady progress toward a launch still more than a year away.

MISO

MISO's market operated throughout the week without a widely reported system-wide emergency, and mild autumn conditions across the Midwest and South kept real-time prices subdued. As with its neighbors, the operational narrative was secondary to institutional and planning activity, which carried the week's substance. MISO's engagement centered on the seams it shares with SPP and on the governance of its market oversight, both of which advanced during the period.

The headline item came on October 22, when MISO and SPP jointly reported that their joint targeted interconnection queue transmission portfolio, a package of five 345-kilovolt seam projects, had become fully subscribed, an important step toward building interregional transfer capability that has been years in the making. The same day, MISO's Advisory Committee requested a formal role in the Independent Market Monitor's best-practices review, reflecting continued stakeholder interest in shaping how the market's independent oversight function evolves. No MISO board meeting fell within the window, and verifiable in-window real-time price figures were not available, but the seams and governance developments made for a moderately active week.

PJM

PJM's week was defined not by its markets, which operated normally under mild conditions, but by an intense and widening policy debate over large loads and data centers. On October 21, FERC convened a technical conference on reliability in a changing energy landscape, where NERC's chief executive delivered a state-of-reliability assessment and panelists examined the integration of data centers and AI compute campuses, dynamic load modeling, declining system inertia, and fuel security for high-load-factor facilities. The conference crystallized concerns that have become especially acute in PJM, where data-center-driven demand growth has collided with capacity-market design, and it followed closely on FERC's earlier rejection of PJM's interim resource adequacy service proposal for large loads.

That rejection reverberated through the week, with consumer advocates arguing it leaves state action as the main protection against data-center cost shifts, and the issue reached the political arena when the president publicly asserted that large data centers should generate their own electricity. Corporate consolidation drew equal attention as Virginia's governor and State Corporation Commission staff pressed for extensive conditions on the proposed $67 billion Dominion-NextEra merger, with staff recommending rejection of the deal as proposed absent protections including a multi-year residential rate freeze, substantially larger bill credits, and a financially separate entity to serve large data-center load, ahead of November hearings. NextEra's leadership addressed the transaction on its third-quarter earnings call, and New Jersey moved to direct roughly $500 million in carbon-auction proceeds toward easing customer bills.

ISONE

ISO New England reported a normal fall operating pattern with no system-wide emergency, as mild shoulder-season weather kept demand and prices moderate across the six-state region. Beneath the calm operations, the grid operator continued to flag the thin capacity margins projected for the coldest early-winter weeks, a recurring structural concern for a region heavily dependent on imported fuel. The week's meaningful activity, however, came through a cluster of market-design and regulatory developments rather than through daily operations.

On October 22, ISO-NE disclosed that a majority of the new projects in its transitional interconnection cluster had withdrawn from the queue, with affected projects facing cost estimates averaging more than $100 million, underscoring how rising network-upgrade costs are reshaping the development pipeline. Two days earlier the operator reduced its non-performance factor from 115 to 110 percent, easing operating-reserve requirements in the energy markets, and on October 19 FERC approved ISO-NE's first-of-its-kind asset condition reviewer role, intended to bring added scrutiny and transparency to local transmission upgrades. Generators, meanwhile, raised legal and market concerns about the operator's proposed treatment of large loads, echoing the region-crossing large-load debate that dominated the week nationally.

NYISO

NYISO had a quiet operational week with no notable in-window price event and no emergency actions, as mild conditions prevailed across New York State. The operator issued no public press releases during the period, and the substance of the week lay in two stakeholder processes, both touching the themes of large-load accommodation and resource adequacy that are increasingly central to New York's grid planning. Markets themselves gave little to report.

On October 22, NYISO's large-load interconnection framework, developed in response to a FERC show-cause directive, met a lukewarm reception, passing one stakeholder committee but failing another amid widespread abstentions and opposition from some state agencies, leaving the proposal's path uncertain. Earlier, on October 18, NYISO and its Market Monitoring Unit publicly disagreed over the assumptions underlying the draft Reliability Needs Assessment, with the monitor warning that the assumptions had grown overly conservative and that market incentives alone would not close projected capacity gaps, even as the final draft advanced. The two items made for a thin-to-moderate week, weighted toward process rather than market outcomes.

AESO

Alberta's market operated without a system-wide emergency, and pool prices eased sharply as the week progressed. The weekly average pool price for the period spanning the window fell to roughly $34.53 per megawatt-hour, down about 43 percent from the prior week, with the in-window days of the weekend settling softly in the high single digits to low $20s per megawatt-hour. A pronounced evening price spike that briefly reached around $805 per megawatt-hour occurred on October 13, just before the window opened, so the reporting period itself was comparatively calm, with internal load peaking near 11,088 megawatts mid-month and the thirty-day rolling average holding in the high $30s.

Policy and large-load developments were the richer story in Alberta. The province confirmed its winter disconnection protections for residential customers, and on October 20 the Alberta Utilities Commission released the first distribution system plans from the province's major electric distributors while also holding a hearing on a proposed power station and transmission project. Load growth continued to dominate the structural outlook, with large-load connection requests reported at roughly 19,600 megawatts against a record system peak near 12,785 megawatts, and AESO's initial 1,200-megawatt large-load allocation now fully committed, including a large block for a Meta data-center project in Sturgeon County and a further allocation tied to a Keephills facility. The feedback window on the first tranche of restructured energy market rules also closed during the period, with AESO expecting to respond by the end of November.

IESO

Ontario's renewed wholesale market continued normal operations throughout the week, with attention turning toward winter adequacy as the province prepares for colder months and the retirement of older nuclear capacity. The system operator's recent arrangement to import 600 megawatts from New York through a U.S. generator, beginning November 1, reflects a winter in which capacity has tightened; the most recent capacity auction fell modestly short of its winter target and cleared at a record-high price per megawatt of roughly $725 per business day. Regulated price plan changes taking effect November 1 will adjust time-of-use and tiered rates and trim the provincial electricity rebate, shifting more cost onto consumers.

On the market-design front, IESO proposed on October 20 to allow battery storage resources to participate in its frequency-regulation market, a change that would let transmission-connected storage stack regulation service with energy and operating reserve as part of the next phase of its storage integration project, with stakeholder feedback on the proposal due at the end of the month. Separately, Ontario's electricity distributors were reported to be facing potentially sweeping policy changes, signaling a broader reexamination of the distribution sector. With a concrete market-design proposal, active winter-supply arrangements, and pending rate changes, Ontario had a moderately eventful week spanning both wholesale and retail dimensions.

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