

Data-Center Costs Dominate as DOE Weighs in on PJM and ROWE Launches

October 3-9, 2026

Executive Summary

The week of October 3-9 confirmed that the question of who pays for data-center and large-load growth has become the organizing issue across North American wholesale power markets, overtaking operational news in a mild early-autumn shoulder season. The clearest signal came from Washington, where the U.S. Department of Energy filed a statement of position at FERC on October 7 urging PJM to redesign its Reliability Backstop Procurement so that data centers and other large loads, rather than households, fund the generation and infrastructure they require. DOE described the intervention as its first FERC filing of its kind in at least five years, lending federal weight to a cost-allocation debate also playing out in MISO, where an accelerated interconnection-queue proposal and a new large-load study drew competing comments and protests, and in ERCOT and CAISO, where hyperscaler demand framed nearly every policy discussion. The same theme surfaced commercially in the Google-Constellation nuclear agreement unveiled October 6, a twenty-year arrangement backing roughly \$4.3 billion of uprates across eleven PJM reactors.

Western market structure was the week's second major thread. On October 6 the West-Wide Governance Pathways Launch Committee approved the inaugural five-member board of the Regional Organization for Western Energy, the body that will carry EDAM-era governance toward the 2027 transition, even as a newly formed advocacy group publicly challenged the board's independence a day later. The parallel contest between CAISO's EDAM and SPP's Markets+ continued, with an Arizona commissioner reaffirming support for Markets+ and an Aurora Energy Research study estimating that disciplined seams practices could preserve as much as \$840 million a year in savings under a split Western day-ahead market. Operationally, the dominant event was a record late-season heat wave across Southern California that prompted CAISO to invoke restricted maintenance operations on October 5 and 6 without ultimately calling a Flex Alert or shedding load, while most other regions ran quietly at well-below-peak demand. The net picture was a market set defined far more by regulatory, governance, and commercial structuring than by scarcity pricing.

CAISO

CAISO operated through the entire week without a system-wide emergency, but it did so against a record-breaking late-season heat wave across Southern California. The grid operator issued Restricted Maintenance Operations notices for the roughly 10 a.m. to 10 p.m. windows on October 5 and 6, asking suppliers to defer work that would reduce generation or transmission availability, while stating that it was not forecasting supply shortfalls. No Flex Alert and no rolling outages were ultimately called. San Diego reached 105 degrees on October 3, its first October reading above 100 degrees since 1987, and localized distribution outages briefly affected roughly 23,000 Los

Angeles County customers at the peak before easing. Specific real-time peak prices for the window could not be independently verified from a primary pricing source, and the operational record is best described as elevated demand managed without declared scarcity.

Policy and governance activity was unusually concentrated. CAISO hosted its 2026 Stakeholder Symposium in Sacramento on October 5 and 6 under the theme of powering the future, with FERC Commissioner Judy Chang delivering an opening keynote and panels devoted to the first movers' EDAM experience and the 2027 governance transition. The ISO Board of Governors held a brief executive session on October 5, the

only governing meeting inside the window. Separately, the California Public Utilities Commission's October 8 voting meeting carried a slate of electricity items, including a proposed PG&E agreement to energize a 250-megawatt Google data center in San Jose and a cost true-up tied to extended operations at Diablo Canyon; these items were on the agenda, though final vote outcomes could not be confirmed within the window. Taken together, the week reinforced that California's near-term agenda is dominated by large-load interconnection and the mechanics of the coming regional-governance shift.

WEIM/EDAM

The Western Energy Imbalance Market and the Extended Day-Ahead Market continued to provide regional coordination, but the defining in-window story was governance rather than dispatch. On October 6 the West-Wide Governance Pathways Launch Committee approved the first five-member board of the Regional Organization for Western Energy, naming John Di Stasio, Evelyn Kahl, Paul Kjellander, Deborah Smith, and Rebecca Wagner to stand up corporate governance, negotiate foundational agreements, and make the FERC filings needed ahead of the 2027 transition to independent Western market governance. Several public-interest organizations welcomed the slate, but on October 7 a newly launched advocacy group questioned the board's independence, drawing a sharp response from ROWE's interim president, who characterized the criticism as a smear campaign. The exchange underscored how contested the legitimacy of the new governance structure remains even as its institutional scaffolding is assembled.

Implementation and the broader regional-market contest also advanced. At the CAISO symposium, PacifiCorp implementers shared lessons for utilities preparing to join EDAM and highlighted early benefits, while a first-movers panel brought together executives from Portland General Electric, Pacific Power, Southern California Edison, and CAISO. The competition between EDAM and SPP's Markets+ stayed in focus: an Arizona Corporation Commission leader pushed back on speculation that the state might shift from Markets+ toward EDAM, and an Aurora Energy Research study released October 8 estimated that best-practice seams coordination could preserve up to roughly \$840 million a year in West-wide savings under a split day-ahead market. In an adjacent resource-adequacy development, the Western Power Pool's Western Resource Adequacy Program approved a new penalty structure and a third subregion on October 8 as it approaches its first binding season. No market-specific real-time price series for the window could be independently verified.

ERCOT

ERCOT ran through a mild, below-peak shoulder-season week with no system-wide energy emergency and no scarcity pricing. Daily peak demand registered around 72,381 megawatts on October 6 and 73,190 megawatts on October 7, with forecast peaks near 75,500 and 74,600 megawatts for October 8 and 9, all far below the all-time system record of 91,090 megawatts set on July 22, 2026. Low wind output was offset by strong solar production, and nothing in the public operational record indicated quadruple-digit real-time prices. The week's operational signal, in short, was an unremarkable one for a market whose attention has moved almost entirely to longer-term demand growth.

That demand story dominated the policy conversation. At the Gulf Coast Power Association's fall conference in Texas, Google's head of data-center infrastructure strategy, Amanda Peterson Corio, argued on October 8 that data centers represent the future of power demand, appearing alongside an Onco executive in a session that touched on cost allocation and transmission rates. The remarks landed against the backdrop of Texas's broader effort to manage an interconnection queue that has swelled toward roughly 474 gigawatts, much of it large load, and a state moratorium on new data-center interconnections pending further study. No fresh official action from the Public Utility Commission of Texas or ERCOT fell strictly within the window, leaving the conference commentary as the week's most consequential ERCOT development and a reminder that the Texas debate is now squarely about who connects, in what order, and on what terms.

SPP

SPP's Integrated Marketplace operated without a publicly identified region-wide emergency, and no in-window real-time price, wind record, or congestion event surfaced in the verifiable record; shoulder-season conditions left the operational week quiet. The more substantive news was organizational. On October 7 SPP announced that it had promoted David Kelley to executive vice president and chief financial and strategy officer and elevated Kimberly Lindsey O'Guinn to vice president of regulatory and stakeholder affairs, both reporting to chief executive Lanny Nickell. The appointments signaled continuity in SPP's leadership as the organization balances its traditional footprint against an ambitious Western expansion agenda.

Transmission and generation developments rounded out the week. On October 5 SPP joined MISO and PJM in proposing to replace the long-standing 2004 freeze date used to allocate firm

flow entitlements in their market-to-market congestion coordination, a technical but consequential change to how the three large Eastern RTOs share seams revenues and responsibilities. Within the SPP footprint, Texas regulators approved Southwestern Public Service, an Xcel Energy subsidiary, to add more than 3,700 megawatts of new generation as it moves toward closing its Tolk coal station in 2029. No SPP board or Members Committee meeting fell inside the window, with the next major governance gathering scheduled for November, so the week's SPP activity was best characterized as leadership and planning groundwork rather than market operations.

SPP Markets+

SPP's Markets+ remained in its implementation phase and therefore produced no live daily real-time prices, but it was the most active of SPP's two market lines on the policy and governance front. On October 5 the SPP board members overseeing Markets+ gave independent-sector participants additional time to craft a compromise that would protect independents' voting rights alongside those of investor-owned utilities and public-power entities, an unresolved governance question that bears directly on how the Western day-ahead market will be run. The outcome will shape the balance of influence among the diverse participant classes that Markets+ is trying to hold together ahead of go-live.

The broader contest for Western participants also animated the week. An Arizona Corporation Commission leader reaffirmed the state's support for Markets+ on October 6, pushing back on reports that Arizona utilities might reconsider in favor of CAISO's EDAM. On October 8 the Aurora Energy Research study on Western market seams quantified the stakes, estimating that disciplined seams coordination could preserve as much as roughly \$840 million a year in West-wide savings even under a split day-ahead market in which Markets+ and EDAM coexist. For Markets+, the message of the week was that its commercial case increasingly rests on demonstrating that a divided West can still capture most of the efficiency of a single market, provided the seams are managed well and its governance questions are settled.

MISO

MISO's market operated throughout the week without a widely reported system-wide emergency or notable price event, consistent with mild shoulder-season demand; the in-window activity was concentrated at FERC rather than on the system. The most contested item was MISO's proposal to accelerate its

oldest legacy interconnection cycle, the roughly 71-gigawatt Definitive Planning Phase 2022 cluster, by allowing penalty-free exits before a key decision point, raising the cost-increase threshold for penalty-free withdrawal, and capping the final study phase. MISO sought a FERC decision by October 19, warning of slippage of eighteen months or more otherwise, and the filing drew tentative support from the Organization of MISO States on October 5 along with endorsements from several developers and utilities, even as an independent power producer protested that the plan shifts risk onto remaining interconnection customers.

A second interconnection initiative targeted large loads directly. MISO asked FERC to approve a Large Load Addition Resource Study that would pair loads greater than 200 megawatts with new generation in the same local resource zone through a 120-day study process, with the paired resources required to stay matched for at least fifteen years; the request, filed at the start of the month and reported on October 5, seeks a decision by early December and responds to a mid-year FERC finding that MISO's large-load rules were inadequate. No MISO board or major committee meeting and no capacity or resource-adequacy auction fell within the window. The week's MISO story was thus a procedural one, but a revealing one, showing a grid operator trying to clear a congested queue and build a defensible framework for connecting very large new loads at the same time.

PJM

PJM produced the week's highest-profile developments, both tied to the data-center cost debate rather than to operations, which were unremarkable in the mild shoulder season. On October 7 the U.S. Department of Energy filed a statement of position at FERC urging PJM to revise its Reliability Backstop Procurement so that large loads such as data centers, rather than residential and other ratepayers, fund the generation and infrastructure they drive. DOE framed the filing as its first of this kind at FERC in at least five years and aligned it with concerns that PJM's current cost allocation may be unjust and unreasonable. The intervention landed amid a capacity-market strain that saw the 2028/2029 Base Residual Auction clear at the roughly \$325-per-megawatt-day cap with a sizable shortfall, and it arrived ahead of a special members meeting and a PJM compliance refiling expected later in the month.

The commercial side of the same story was equally striking. On October 6 Google and Constellation Energy announced a twenty-year power-purchase arrangement backing roughly \$4.3 billion of uprates at eleven nuclear units across six sites in Illinois, Pennsylvania, and New Jersey, adding on the order of

890 megawatts by the early 2030s, together with a separate fifteen-year deal covering 2,700 megawatts from Constellation's existing PJM fleet. The transaction, one of a growing series of hyperscaler-nuclear pairings, sharpened the open question of whether such uprate megawatts will ultimately qualify under PJM's evolving rules for colocated and large-load resources. Between the DOE filing and the Google-Constellation deal, PJM sat at the center of the national argument over how an accelerating wave of computing demand should be powered and who should bear its cost.

ISONE

ISO New England reported a normal, mild operating pattern with no heat event, load record, or price spike inside the window, and the substantive activity was concentrated in market design and planning. At the NEPOOL Markets Committee, ISO-NE put finishing touches on its combined capacity-accreditation and seasonal capacity-auction-reform package ahead of stakeholder votes scheduled for November, a long-running effort to align capacity payments with the reliability contribution of different resource types. The region also saw friction on interconnection, as a group of developers filed a FERC complaint on October 5 alleging that structural problems in ISO-NE's first Order 2023 cluster study produced cost estimates severe enough to threaten projects, with battery storage a particular focus.

Forward planning and state policy filled out the week. ISO-NE outlined its 2027 annual work plan on October 4, centering four priorities: capacity-auction reform, large-load interconnection rules, transmission planning consistent with FERC's long-term planning requirements, and a new dynamic operating-reserve product. The ISO also noticed an open meeting of its board of directors. On the policy side, officials from all six New England states expressed openness to new nuclear development during a conference panel, signaling a potential shift in regional generation strategy even though no specific projects or funding commitments were announced. The through-line was a region preparing deliberately for load growth and a changing resource mix rather than reacting to any immediate operational pressure.

NYISO

NYISO was quiet in the verifiable in-window record, with no heat event, demand record, or notable price movement and no board or committee outcome that could be independently confirmed for the week. The single clear development was the latest draft of the 2026 Reliability Needs Assessment, discussed through the Electric System Planning Working Group, in which NYISO delivered a pointed warning that aging generation is no

longer a future concern but a present one. The draft projected that reliability margins begin to erode around the early 2030s as generator retirements, surging large loads and data centers, and the growing but variable contribution of renewables converge.

Beyond the reliability assessment, the public record offered little NYISO-specific news for October 3-9, and it would overstate the week to suggest otherwise. No New York Public Service Commission action, generator announcement, or offshore-wind or clean-energy milestone within the window could be verified. The practical significance of the week for New York therefore lies in the assessment's framing: it elevates the adequacy debate from a long-horizon planning exercise to a near-term policy imperative, and it places New York alongside its neighbors in confronting how retirements and new electricity demand will be reconciled without eroding reliability.

AESO

Alberta's market operated without a publicly reported system-wide emergency, and the week's clearest operational read came from an independent market report published October 6 covering data through early in the window. It showed a thirty-day average pool price near \$30 per megawatt-hour and a firmer recent stretch, with a brief spike above \$400 per megawatt-hour in a single evening hour at the very start of the month and Alberta internal load peaking around 10,622 megawatts on October 4. Prices thus remained moderate by historical Alberta standards, with short-lived evening tightness rather than sustained scarcity, even as the province continues its multi-year transition toward a restructured energy market targeted for implementation in mid-2027.

Structural and connection news accompanied the price data. On October 7 AESO issued a notice of approval for the Marguerite Lake compressed-air energy-storage project connection under its abbreviated needs-approval process, a modest but notable addition to the province's storage pipeline. On the market-design front, AESO indicated it intends to launch the restructured energy market without a real-time deliverability constraint on its thirty-minute ramping-reserve product, a choice that bears on how flexibly the new market will manage reserves; the same discussion surfaced the growing incidence of wind and solar curtailment tied to transmission constraints. The combination pointed to an Alberta market whose near-term attention is fixed less on daily prices than on the design decisions that will define the restructured market's first years.

IESO

Ontario's renewed wholesale market continued normal operations in its second year under a nodal design, with no verifiable in-window demand record or notable price event, and the week's substance lay in capacity procurement and recognition rather than market operations. An independent advisory report published October 7 detailed IESO's move to secure 600 megawatts of imports from New York for the coming winter under a six-month bilateral arrangement announced at the start of the month, alongside a decision to raise Capacity Auction targets by 200 megawatts for both the summer 2027 and winter 2027/28 commitment periods. The upcoming auction's pre-qualification deadline was also extended to October 9, placing a procurement milestone squarely within the window.

Institutional news and the sector calendar filled out the week. On October 6 IESO was named ENERGY STAR Utility of the Year for 2026 in recognition of its Save on Energy efficiency programs, and the operator issued reminders for its mid-October stakeholder engagement sessions, which fall just beyond the reporting window. Trade coverage previewed the Ontario Energy Conference, scheduled for mid-October and notable for new leadership atop both IESO and Hydro One, foreshadowing a debate over how aggressively the province should plan for demand growth. For Ontario, the period was one of steady administration and forward positioning, with the capacity actions the most materially significant items and the leadership transition the one to watch in the weeks ahead.

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