The Load Wave and What Comes After It

Where the utility industry actually is in September 2026, what the data center buildout is doing to it, and the use cases GridCORTEX needs next

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Why this paper

GridCORTEX carries 156 validated use cases across 22 domains. That library was built against the utility problem set as it stood a year ago: storms, wildfire, aging assets, the grid edge, the first wave of data center interconnection requests. The problem set has moved. In the last twelve months the industry has been through the largest load forecast revision in its history, the tightest capacity auction in PJM's history, a federal rulemaking that turns data centers from customers into registered reliability entities, a Texas governor pausing data center interconnections outright, a state moratorium in New York, an executive order restricting foreign bulk power equipment, and a utility merger that creates the largest regulated electric business in the world.

Some of that reinforces what we already sell. Some of it exposes gaps, and the gaps are exactly where the money is moving. This paper does three things: it lays out where the industry is, with numbers and dates rather than adjectives; it goes deep on the data center wave from every seat at the table, because that is the trend that reorganizes the others; and it proposes the next set of use cases, with an argument for which few matter most and which I chose to leave out.

I have written it for us, not for a client. It is opinionated on purpose. Where a number is contested or thinly sourced I say so.

The three facts that reorganize everything

Everything else in this paper hangs off three facts.

First, the load is real, but a third or more of the queue is not. NERC's 2025 Long-Term Reliability Assessment, published January 29, 2026, projects 224 GW of summer peak growth over ten years, 69 percent above the prior year's projection, and puts MISO, PJM, ERCOT, WECC-Basin and WECC-Northwest at high risk by 2030. Grid Strategies' own read is about 150 GW of growth by 2030, roughly 90 GW of it data centers. Against that, Wood Mackenzie counted 1,066 GW of US data center power requests in August 2026 and expects utilities to commit to about 28 percent of them; the rest is duplicate requests shopped across utilities and long-shot pitches. Oncor alone reports 298 GW of service requests against a system that peaks under 30 GW. ERCOT's large load queue went from 233 GW at the end of 2025 to roughly 474 GW by August 2026, about 90 percent data centers. Exelon cut its high-

probability data center load 40 percent to 11 GW once it applied stricter vetting. PJM trimmed its 2030 winter forecast 4.3 percent after requiring firm commitments through 2032. The load wave is genuine and the queue is a fiction, and the whole industry's planning problem is now telling one from the other.

Second, supply is constrained by turbine slots and transformers, not by permits or capital. Gas turbine orders hit 100 GW in 2025 against 60 to 70 GW of annual manufacturing capacity. GE Vernova's backlog is reported at 116 GW and sold out through 2030, Siemens Energy near 70 GW, Mitsubishi 35 GW. Large frame lead times are five to seven years and prices are up roughly 195 percent since 2019. Power transformer lead times run 2.5 to 4 years depending on class. The Duke Nicholas Institute study that found roughly 100 GW of headroom on the existing grid if new load will curtail 0.25 to 0.5 percent of hours is the most important planning paper of the decade, because it is the only path to serving this load on the timeline the developers want. Flexibility is not a nice-to-have anymore; it is the supply.

Third, affordability now governs regulation. Investor-owned utilities requested a record $22 billion in rate increases in 2025 and another $18.6 billion in the first half of 2026. EIA has the average household at 18.6 cents per kWh in 2027, up from 16.5 in 2024. PJM's Independent Market Monitor attributed $9.3 billion of 2025/26 capacity cost, a 174 percent increase, to data center demand. Electricity bills are a midterm issue. Governors are acting directly: Shapiro's GRID executive order in Pennsylvania, Abbott's audit directive in Texas, Hochul's moratorium in New York, tax exemption pauses in Arizona and Illinois. Every utility capital plan now has to survive an affordability test that did not exist two years ago, and every data center contract now has to demonstrate that residential customers are held harmless. That is the buying condition for everything we sell into planning, regulatory and customer domains.

If we get those three right, the rest of the strategy follows.

The load wave by the numbers

LBNL's June 2026 update puts 2024 US data center consumption at 192 TWh, 4.7 percent of US electricity, and projects 464 TWh in 2028 and 649 TWh in 2030 in the reference case, with a range of 9.5 to 15.3 percent of national electricity by 2030. EPRI's February 2026 scenarios run 9 to 17 percent by 2030. EIA's September 2026 outlook forecasts record generation of 4,368 billion kWh in 2026 and retail sales of 4,135 billion kWh, with growth concentrated in the West South Central region, which is to say Texas. EIA also cut its Texas 2027 demand growth forecast from 14 percent to 6 percent after the Abbott directive, the first material downward revision of the load story I have seen from a federal source.

The utility disclosures tell the same story from the ground. Dominion has 53.8 GW of contracted data center capacity. AEP has 56 GW of contracted large load through 2030, 36 GW of it in AEP Texas, about 90 percent data centers. Southern has 17 GW contracted, including a 3.2 GW OpenAI facility near Savannah. Duke has 7.6 GW executed and 7.8 GW in late-stage pipeline. Entergy has Meta's Hyperion campus, now expanded to 5 GW, and a 7 to 12 GW pipeline behind it. Xcel has 2 GW contracted and a 20 GW pipeline of which 4 GW it calls high probability. CenterPoint has 17 GW submitted to ERCOT's new process against a Houston peak of 21 GW. PG&E has a 12.7 GW pipeline. Hyperscaler capital expenditure guidance for 2026 is $660 to $725 billion combined depending on who is counting, roughly double 2025, and Microsoft has disclosed an $80 billion Azure backlog it cannot fill for lack of power.

The real estate numbers are just as stark. JLL reports 25 GW of North American absorption in the first half of 2026, vacancy at 1 percent for a third straight year, 66 GW under construction and 95 percent of it pre-committed. Texas leads with 26 GW, Virginia 13 GW, and frontier markets account for 77 percent

of pipeline expansion. Atlanta became the most active construction market for the first time. Northern Virginia sits at 0.2 percent vacancy.

Two things about these numbers matter for us. The first is that the contracted figures are now large enough that utility earnings depend on them, which means the utilities are exposed if the load does not show up. Georgia Power agreed to absorb costs through 2031 if its 10 GW of approved generation, 80 percent of it for data centers, is not needed. That is a new kind of risk on a utility balance sheet and nobody has a tool for managing it. The second is that the requests are concentrated in a handful of utilities and regions, which is exactly what GridGLOBE is built to show.

Data centers from every seat at the table

The mistake most vendors make is to talk about data centers as if there were one point of view. There are at least four, and they want different things from the grid and from each other.

The developer's seat

From the developer's chair the problem is time to power. JLL's 2026 outlook puts the average grid connection wait in primary markets above four years, against 12 to 18 months before 2022. Northern Virginia is quoted at seven years for 100 MW. Bloom Energy's 2026 survey of operators found utilities' delivery timelines run 1.5 to 2 years longer than hyperscalers expect, and that about a third of data centers in 2030 plan to run on 100 percent on-site power. The industry has reorganized around that gap. Site selection is now power first, then fiber, water, land, tax and latency, in that order. "Powered land" is described as the most valuable asset class in digital infrastructure. The bitcoin miners, Hut 8, MARA, TeraWulf, Cipher, IREN, Galaxy, became the dominant supply of near-term interconnected capacity because they already hold energized interconnections.

The flagship projects show the range of answers to the power problem. Crusoe's Abilene campus for Stargate is at 300 MW operating and heading to 1.2 GW by the end of 2026 on a combination of grid and 4.5 GW of on-site gas secured through Engine No. 1, with GE Vernova turbines that Engine No. 1 and Chevron acquired. Vantage's Frontier campus in Shackelford County, Texas, $25 billion and 1.4 GW, runs on an on-site gas microgrid. The Stargate sites in Dona Ana County, New Mexico and Milam County, Texas are gas microgrids; Port Washington, Wisconsin is about 70 percent solar, wind and storage; Saline Township, Michigan is grid plus storage through DTE. Meta's Prometheus in New Albany, Ohio went operational in August 2026 at 562 MW on two on-site gas plants. Meta's Hyperion in Louisiana is grid-served, with Entergy building seven combined cycle units totaling more than 5.2 GW against a single customer contract. xAI's Colossus 2 in Southaven, Mississippi runs on Solar Turbines Titan-350 units through a joint venture with Solaris Energy Infrastructure, 495 MW operating and 1,240 MW planned for 2027, and is in litigation over unpermitted turbines. Microsoft's Fairwater sites in Wisconsin and Atlanta are grid-served by We Energies and Georgia Power. Amazon's Project Rainier in Indiana will draw 2.25 GW from Indiana Michigan Power through two 345 kV substations energizing December 2026, with 878 diesel backup generators on site. Amazon's Susquehanna campus is now a front-of-meter 1.92 GW PPA through 2042 after FERC rejected the behind-the-meter version in November 2024.

The developer's electrical problem inside the fence has changed just as much. NVIDIA's GB200 and GB300 NVL72 racks run around 140 kW; Microsoft states 140 kW per rack and 1,360 kW per row at Fairwater. Vera Rubin ships in the second half of 2026 with 5,000 amp liquid-cooled busbars, and the Kyber rack in 2027 doubles the NVLink domain to 144 GPUs, with third parties talking about 600 kW

racks. To carry that, NVIDIA announced an 800 volt DC architecture that converts 13.8 kV directly to 800 VDC at the facility perimeter, claims a 5 percent end-to-end efficiency gain and 45 percent less copper, and goes to full production in 2027 with ABB, Eaton, GE Vernova, Hitachi Energy, Mitsubishi Electric, Schneider Electric, Siemens and Vertiv as the named system partners. The Open Compute Project's Diablo 400 specification is the rack and power standard. Solid state transformers are being studied but not committed; SemiAnalysis puts them after 2029. The codes have not caught up: there is no DC arc flash model above 600 volts in IEEE 1584 or NFPA 70E, no consensus 800 VDC grounding standard, and NEC 2029 is the first edition expected to address it. Closed loop liquid cooling is now the default at the frontier, which trades water for electricity and adds a large, fast-cycling chiller load with its own power quality signature.

The utility's seat

From the utility's chair the data center is three things at once: the best load growth in a generation, a credit and stranded asset risk, and a reliability hazard.

The growth is obvious. The risk is newer. The tariff response has been fast. EEI counts 25 states with approved large load tariffs and seven pending as of August 2026. The archetype, per the DELTa database, is a 10 year or longer contract, minimum billing at around 80 percent of contracted capacity in 43 percent of filings, collateral in 44 of 77 filings, and change bands of about 20 percent before exit charges apply. AEP Ohio's tariff, approved July 9, 2025, is the reference: 85 percent minimum billing with a four year ramp, exit fees equal to three years of minimum charges, collateral, and study fees of $10,000 to $100,000. Its effect was immediate; AEP Ohio's pipeline fell from more than 30 GW to 13 GW once the tariff took effect, which tells you how much of the original queue was speculative. Dominion's GS-5 class carries an 85 percent transmission demand rate and a reported $1.5 million per MW collateral requirement, and on August 5, 2026 the Virginia SCC ordered Dominion to develop a tariff assigning transmission costs, the 115 mile Valley Link line among them, directly to data centers. PPL's LP-6 class took effect July 1, 2026 with 10 year minimum contracts and 80 percent minimum load. ERCOT now requires site control and $50,000 per MW in financial security.

The reliability hazard is the part utility operators talk about privately. On July 10, 2024, a lightning arrestor failure on a 230 kV line in Northern Virginia caused six faults in 82 seconds, and about 1,500 MW of data center load, roughly 60 facilities, transferred to backup simultaneously; 1,260 MW stayed off for hours, voltage overshot to 1.07 per unit and operators had to pull capacitor banks. ERCOT's record reportedly documents 28 events between 2023 and 2026 where large electronic loads shed 100 MW or more during disturbances. NERC responded with a Level 3 Alert, approved April 16 and issued May 4, 2026, requiring stability margin studies, dynamic fault recorders, corrective actions so that computational loads do not trip on normally cleared faults, and a proposed Computational Load Entity registration at 20 MW aggregate, 60 kV and above. NERC's May 2026 reliability guideline adds harmonic limits, power quality requirements and high resolution monitoring at the point of interconnection to the interconnection requirements themselves. The PUCT approved ERCOT's ride-through rule, NOGRR282 and NPRR1308, on July 9, 2026 for loads of 75 MW and above where half the demand is power electronics, with retrofit cost estimated at $500,000 to $1 million per MW. PJM proposed its own large load ride-through requirements on September 14, 2026. And on July 16, 2026 FERC ordered NERC to file mandatory reliability standards for computational large loads by the end of this year.

That last item is the single most consequential fact in this paper for our business. Data centers are becoming registered, standard-bound entities with compliance obligations, modeling obligations and telemetry obligations, exactly the transition inverter-based resources went through with PRC-029 and

IEEE 2800. Every utility with a large load on its system will need to collect as-designed, as-built and as-left model data, run annual stability studies, monitor ramp rates against operating agreements, and prove it. That is a compliance and analytics product, and we have the pieces for it in the framework already.

The ISO and regulator's seat

From the ISO chair the questions are interconnection process, cost allocation and resource adequacy, and 2026 rewrote all three.

On process, the Secretary of Energy used Federal Power Act authority on October 23, 2025 to direct FERC to open a large load interconnection rulemaking with a 20 MW threshold, standardized studies for standalone and hybrid facilities, a net injection methodology, an option to build, and an expedited 60 day study path for curtailable loads. What FERC actually did on June 18, 2026 was issue six Section 206 show cause orders, one each to PJM, MISO, SPP, CAISO, ISO-NE and NYISO, defining a large load as 50 MW or more above 69 kV and demanding reform in five categories: a distinct large load application and study process, network upgrade cost transparency, standardized co-location terms, flexible and non-firm transmission service for conditionally flexible load, and streamlined interconnection for generation within two substations of a large load. Stakeholder comments were due today. ERCOT and the vertically integrated non-RTO utilities are outside that scope, which means Texas, the Southeast and most of the West are running their own processes. SPP's HILL and HILLGA processes, approved January 14, 2026, offer a 90 day system impact study for large loads and a load-limited interconnection service that auto-terminates five years after commercial operation. PJM's co-location filing of February 23, 2026 caps behind-the-meter generation at 50 MW, excludes diesel and gas backup, and creates interim non-firm, firm contract demand and non-firm contract demand services; its Connect and Manage framework lets a data center connect early in exchange for earlier curtailment. MISO is building a dedicated large load queue and a zero-injection product that Google and Xcel back. ERCOT moved from serial to batch studies, finalized Batch Zero criteria in June, then missed its August 7 study deadline after the governor's directive.

On cost allocation, the fights are about who pays for the transmission and the capacity. PJM's 2027/28 auction cleared at the $333.44 per MW-day cap, 6,623 MW short of the reliability requirement, with 5,100 MW of the 5,250 MW peak increase attributed to data centers; the 2028/29 auction in July 2026 cleared at $325 under the collar for the third year running and drew only 525 MW of new resources. Uncapped, PJM's own simulation put the price at $555 PJM-wide and $777 in ComEd. A Pennsylvania PUC study found PJM meets its loss of load standard through 2030 only in the scenario that excludes new data centers; the reference case is six times the criterion. That is the analysis behind Shapiro's GRID order of August 18, 2026, which requires developers above 25 MW to secure incremental capacity covering their full demand plus all interconnection and upgrade costs, meet clean energy targets, get municipal approval before state permits, and file community benefit plans, and which directs the state to press PJM to curtail data centers first in emergencies if they have not secured capacity.

On resource adequacy, DOE has issued 43 Section 202(c) emergency orders since May 2025 keeping about 4.4 GW of retiring plants online, the orders are being litigated, an appeals court vacated the Michigan one, and the compelled plants are generating far less than they did before the orders. Coal retirements in 2025 were the lowest in 15 years. Gas in the interconnection queue rose 86 percent to 253 GW. TVA's 2026 IRP contemplates 7 to 26 GW of new gas. Global Energy Monitor counts 252 GW of US gas in development, more than 80 GW of it designated for on-site data center supply, and BloombergNEF counts about 100 GW of planned on-site gas for data centers, roughly 18 percent of the

existing fleet. Winter Storm Fern in January 2026 was, in NERC's words, a classic near miss; the FERC-NERC report of September 10, 2026 found unplanned outages in the Eastern Interconnection at 49,700 MW versus 90,500 MW in Elliott, no manual load shed, and MISO importing 9 GW mostly from PJM. Winterization is working; the unresolved issue is gas-electric coordination.

The community's seat

The fourth seat is the one the industry keeps underestimating. Data Center Watch counted at least 75 projects worth about $130 billion blocked or delayed in the first quarter of 2026 alone, opposition groups in 49 states that more than doubled from 396 at the end of 2025 to 833 by March 2026, and more than 500,000 Americans in resistance groups. JLL's framing is the one to remember: 79 percent of Americans support US leadership in AI and 14 percent support a data center near them, a 65 point gap. More than 300 state bills were filed in the first six weeks of 2026 with moratorium proposals in 14 states. The water, noise, air permit and tax exemption questions are now formal criteria: water use is an audit item in the Texas directive and a disclosure requirement in Pennsylvania and New York. The xAI turbine litigation in Memphis and Southaven, with the NAACP, SELC and Earthjustice as plaintiffs and a contested count of 27 to 59 unpermitted turbines, is the template case for what happens when on-site generation runs ahead of permits.

For a utility this seat matters because the utility ends up as the public face of the project. The rate case, the siting hearing and the county board meeting are where the utility, not the hyperscaler, defends the load. A community benefit and impact dossier for a large load, built from the utility's own data, is a real product.

Flexibility, the thing that reconciles the seats

The only idea that satisfies all four seats at once is flexible load, so it is worth being precise about what it means.

EPRI's DCFlex program, now at nine demonstration sites with Compass, Constellation, Emerald AI, Google, National Grid, Nebius, NVIDIA, Oracle and PADO AI, defines five flexibility classes by notification time, duration and depth, across three pillars: managed workloads, reduced plant consumption, and backup power. Pilots achieved up to 40 percent flexibility. Boston University modeling puts AI training at 18 to 55 percent flexibility relative to average draw; training is checkpointable and interruptible, inference is latency bound and much less so. Emerald AI demonstrated a 25 percent reduction over three hours for Salt River Project and 20 percent in a simulated Portland General Electric emergency, and integrated with NVIDIA's DSX Flex on March 16, 2026. Google announced 1 GW of demand response embedded in PPAs with Indiana Michigan Power, TVA, Entergy Arkansas, Minnesota Power and DTE on March 19, 2026, treated as a defined capacity resource in planning. Southern's OpenAI contract includes 1 GW of flexible demand response, the first codified flexibility provision in a large load contract. NVIDIA's GB300 power smoothing, capacitors filling half the power supply volume plus a hardware power burner, cut peak grid demand 30 percent while training versus GB200, and NVIDIA notes the reason it matters: generation ramp response takes one to ninety minutes.

The unresolved issue is control. Silicon Valley Power's operations chief called 100 percent control of the load-side breaker non-negotiable for faster interconnection. Data centers resist losing operational autonomy. Texas SB6 gives utilities remote curtailment authority for new large loads during firm load shed only, and only after ERCOT has exhausted market services; there is no kill switch in the sense the press describes. The commercial negotiation of the next three years is about who holds the dispatch

signal, how it is verified, and how it is paid. That negotiation needs software on both sides, and nobody has built the utility side of it yet.

The other trends, briefly and with a point of view

Distributed energy has become a battery story. Sunrun's battery attach rate went from 62 to 74 percent in six quarters and it dispatched 425 MW across 2025 from 4.6 GWh of networked storage. Base Power sells battery subscriptions in Texas at $19 to $29 a month with no solar. The residential solar credit is gone but third-party ownership keeps credits through 2030, so the market migrates to leases rather than dying; SEIA expects a 21 percent contraction in 2026 and 6 percent residential growth a year after. Community solar is the real casualty. Grid-scale storage set a record of 6.7 GW and 20.2 GWh in one quarter, and EIA expects 64.9 GW of utility-scale batteries by the end of 2026, more than double early 2025. The August 26, 2026 executive order restricting foreign bulk power equipment at 69 kV and above, inverters and batteries included, is the new supply chain risk on top of the transformer one; BloombergNEF expects storage delays and cancellations, and DOE has until late December to write the rules.

Virtual power plants got their first hyperscaler check. PG&E's SHARE pilot, launched September 10, 2026, is fully funded by Google through 2027. Sunrun, Tesla and Renew Home offered utilities 16.8 GW across 12 million devices in June, positioned explicitly as speed to power. Illinois mandated a scheduled dispatch VPP and 3 GW of storage by 2030 and approved ComEd's program July 8; New Jersey is procuring 150 MW of behind-the-meter storage at up to $200 per kW-year. DOE's liftoff target remains 80 to 160 GW by 2030 from about 33 GW today. Wood Mackenzie puts US VPP capacity at 37.5 GW. Order 2222 is not where the value is being created; state programs are, and we should stop leading with 2222 outside the ISOs where it is live.

Electrification slowed and shifted. EV spending fell from $31 billion in the third quarter of 2025 to about $18 billion a quarter after the credit ended, and stayed there. The more interesting number is E3's finding for GM that bidirectional charging is worth $2,200 to $2,750 per vehicle per year in constrained regions against $100 to $400 for one-way managed charging, with 250,000 bidirectional-capable GM vehicles already deployed. School bus V2G is real capacity now, 230 buses operating and 14,000 committed. Heat pump shipments are flat while gas furnace shipments fell 11.6 percent. The feeder-level consequences, transformer overloads and clustering, are the distribution planning problem of the next five years and we cover them.

Australia is the preview. South Australia hit 57 MW of minimum operational demand on April 18, 2026, within a rounding error of zero, and negative prices in 22 percent of dispatch intervals. Rooftop PV is 26.4 GW across 3.9 million systems. Australia's answer was a multi-billion dollar home battery subsidy and export management, not more solar, and New South Wales retail prices fell 10.7 percent on July 1, 2026, the first decline in five years, in the same year US bills rose 8 to 10 percent. Great Britain's connection reform cut a 700 GW queue down to a 283 GW pipeline with confirmed dates. Both are the models North American regulators will reach for, and the GridGLOBE points of view already say so.

Markets and M&A. NextEra and Dominion agreed to combine on May 18, 2026 in a $66.8 billion all-stock deal creating the largest regulated electric utility in the world; BlackRock and EQT are taking AES private for $33.4 billion; Constellation closed Calpine in January and is divesting 4.4 GW of PJM gas to LS Power for $5 billion as the remedy; NRG bought LS Power's generation; Blackstone is buying TXNM. Post-merger data unification and portfolio due diligence, which we have in the library, just became the

largest single opportunity in the sector by dollars. In the West, Bonneville is reconsidering its Markets+ choice against EDAM with a draft decision due by the end of 2026, and south-to-north flows on the California-Oregon Intertie now worry BPA dispatchers because the WECC-1 remedial action scheme was never designed for them.

Reliability and wildfire. PRC-029 and PRC-030 ride-through standards for inverter-based resources are in force and NERC's IBR registration is in its final stretch. Xcel faces a Texas Attorney General suit over Smokehouse Creek with more than $1 billion claimed; there is no settlement, and Xcel agreed in February 2026 to replace at-risk poles under threat of injunction. PacifiCorp's Oregon exposure is $2.2 billion and at the state supreme court. California's SB 254 study report and Texas's PUCT vegetation blueprint are the two regulatory documents that will shape wildfire capital plans in 2027. Nothing here changes our wildfire domain except to confirm the buyer is now the general counsel as much as the operations VP.

Nuclear and firm supply. Crane restarts in 2027 on a $1 billion DOE loan and a 20 year Microsoft PPA; Palisades has slipped repeatedly with fuel loading reported to have begun August 31, 2026; Duane Arnold got a $1.9 billion DOE loan this month. The hyperscaler SMR commitments, Amazon and X-energy at 960 MW, Google and Kairos at 500 MW, Meta and TerraPower at up to 4 GW, Meta and Oklo at 1.2 GW, are all 2030 or later, PJM dropped Oklo from its study cycle on September 1, and I treat SMR first power before 2032 as a single-digit probability outside federal sites. Fervo's 396 MW geothermal PPA with Google, online 2028 with an option toward 1 GW, is the credible new firm resource. Commonwealth Fusion raised its fourth billion and targets net energy at SPARC in 2027 with a first commercial plant at Dominion's Chesterfield site in the early 2030s; I would not plan on it. Our nuclear domain is right to focus on the existing fleet, uprates, restarts and life extension, because that is where the megawatts are before 2032.

AI in utilities. The honest finding is that named, at-scale production AI deployments at utilities remain thin in the public record relative to the volume of talk. EPRI's Open Power AI Consortium with NVIDIA is the institutional anchor. Santee Cooper's Google partnership on load forecasting and OG&E's Bidgely work on rate design are the kind of specific deployments that exist. Uptime's 2026 survey found data center operators' expectations for AI in operations cooled slightly, with confidence in sensor analytics and predictive maintenance rather than autonomous control. That is consistent with our positioning: read-only, human in the loop, intelligence above the grid. It also means the buyers are still early, which is good for us and bad for anyone selling autonomy.

Where the current 156 fall short

I went through the library against the facts above. The framework holds up well on the operations, storm, wildfire, asset, vegetation, nuclear and robotics domains, and those need tuning rather than new entries. The gaps cluster in five places.

Large load is written from the utility side only and stops at interconnection. Domain 12 covers the interconnection modeler, the resilience twin, site feasibility, flexible load orchestration, tariff structuring, and the co-location twin. It does not cover what happens after the contract is signed: minimum bill and collateral administration, exit fee exposure, ramp schedule compliance, ride-through and power quality compliance under the NERC alert and the ERCOT rule, the direct assignment of transmission costs, or the community dossier the utility has to defend at the county board. It also does

not cover the queue itself: nothing in the library helps a utility separate the 28 percent that is real from the phantom requests, and that is the first question every planning VP is being asked.

We have no data center operator seat. The framework is written for the utility. The developer, the operator and the neocloud have a mirror set of problems, telemetry to the utility, flexibility commitments they have to honor and prove, on-site generation they have to dispatch against grid signals, batteries they have to size for training transients, permits they have to stay inside, and an 800 VDC electrical plant nobody has operated at scale. NVIDIA's DSX stack, Max-Q, Flex, Exchange and Sim, plus the Omniverse DSX digital twin blueprint with Schneider, Siemens, Vertiv, Eaton, Emerald AI, GE Vernova and Hitachi as partners, is the platform the operator side will be built on. We are an NVIDIA partner selling to utilities and we have nothing on the other side of the meter. That is the biggest single gap.

Resource adequacy and capacity market exposure are missing. Use case 20.3 covers resource adequacy for the system operator. Nothing covers the load-serving entity's exposure to a capped PJM auction, the economics of a 202(c) deferred retirement, the value of a turbine slot, the backstop procurement cost share Shapiro wants data centers to carry, or the gas-electric coordination problem the FERC-NERC report named as unresolved.

Affordability is treated as a customer problem, not a regulatory strategy problem. We have vulnerable customer outreach, bill impact simulation and rate case data requests. We do not have the thing regulators are actually asking for: an attributable, defensible accounting of what large loads cost and save residential customers, built to the standard of the PJM market monitor's 174 percent finding and the EPRI finding that data centers have so far lowered bills about 6 percent. Whoever can produce that number credibly for a specific utility owns the rate case.

Supply chain and the foreign equipment order are not covered. The August 26 executive order creates a compliance inventory obligation for every bulk power asset owner within months, on top of transformer lead times of two to four years. Use case 15.4 is a procurement intelligence tool. It is not an equipment provenance and mitigation program, and that program will be mandatory.

Smaller gaps: minimum demand and negative price operations on distribution systems, the Australian problem that California, Hawaii and eventually Texas are heading into; flexible load interconnection for customers below the large load threshold, the PG&E Flex Connect pattern, which we cover for generation in 6.7 but not for load; bidirectional EV capacity valuation now that E3 has put a number on it; merger and portfolio due diligence at the scale of NextEra-Dominion, which 15.6 and 15.7 touch but were not written for.

The proposed expansion

Thirty-one use cases follow, in five groups. Each one names the buyer, the reason it exists now, and the GridCORTEX construct it builds on, so it can be written up in the library format quickly. I have ranked within groups. The top six across all groups are called out afterward, with the argument, and I close with what I left out.

Group A: Large load lifecycle, the utility side (extends Domain 12)

A1. Large Load Queue Credibility Scorer. Buyer: VP transmission planning, large customer group. Ranks every request in the queue on site control, deposits paid, duplicate filings across utilities, developer

track record, equipment orders, permits and fiber, producing a committed, probable and phantom classification with an evidence trail. Why now: Wood Mackenzie's 28 percent, Oncor's 298 GW, Exelon's 40 percent cut, PJM's firm commitment requirement. Builds on 12.1 and 20.1.

A2. Large Load Tariff Administration and Exposure Engine. Buyer: CFO, regulatory. Administers minimum bills, ramp schedules, collateral, change bands and exit fees across every large load contract, and reports stranded cost exposure by scenario. Why now: 25 states with tariffs, AEP Ohio's 85 percent minimum, Georgia Power carrying the risk through 2031. Builds on 12.5.

A3. Computational Load Reliability Compliance Twin. Buyer: transmission operations, NERC compliance. Collects as-designed, as-built and as-left load models, runs the annual stability margin study, monitors ramp rates and ride-through performance at the POI against the operating agreement, and produces the evidence package for the NERC Level 3 Alert, ERCOT NOGRR282, PJM's proposal and the mandatory standards due by the end of 2026. Builds on 2.1, 2.4 and 2.6.

A4. Large Load Loss Contingency and Protection Coordinator. Buyer: transmission planning, protection engineering. Models the coincident loss of gigawatts of electronic load on a normally cleared fault, the July 10, 2024 Virginia event, and recommends reclosing practice, capacitor bank staging and protection settings. Builds on 1.6, 2.5 and 2.6.

A5. Flexible Load Contract Operations and Settlement. Buyer: system operations, large customer group. The utility side of DCFlex: issues flexibility calls by class, verifies delivered reduction against metered data, settles payments and penalties, and accredits flexible capacity for planning. Why now: Google's 1 GW, Southern's OpenAI provision, Connect and Manage, SPP's LLRIS. Builds on 6.8 and 12.4.

A6. Bring Your Own Generation and Co-Location Study Engine. Buyer: interconnection engineering. Runs the thermal, short circuit and stability studies for hybrid facilities under PJM's 50 MW behind-the-meter cap, SPP's two-substation rule and Texas SB6's private use network provisions, with net injection and withdrawal accounting. Builds on 12.3 and 12.10.

A7. Transmission Direct Assignment and Cost Allocation Modeler. Buyer: regulatory, transmission planning. Allocates network upgrade and new line costs to the large loads that cause them under the Virginia SCC order, FERC's cost transparency category and PUCT Project 58484, with ratepayer impact by class. Builds on 14.2 and 12.5.

A8. Large Load Community Impact and Benefit Dossier. Buyer: external affairs, regulatory. Builds the county board and PUC package: load, water, air permits, on-site generation, tax incentives received, community benefits, and the residential bill effect, to the disclosure standard of the Texas audit, the Pennsylvania GRID order and New York's framework. Builds on 14.1 and 7.7.

A9. Speed to Power Sequencer. Buyer: large customer group, engineering and construction. Critical path for energizing a specific site: transformer and breaker lead times, substation build, temporary service, bridge generation, batch study milestones, and the earliest credible energization date with confidence bands. Builds on 12.1 and 15.4.

Group B: The data center operator seat (new domain: AI Factory Grid Interface)

B1. AI Factory Utility Telemetry and Compliance Gateway. Buyer: data center operator, hyperscaler energy team. The operator side of A3: publishes POI power quality, ramp, backup transfer and forecast telemetry to the utility, tracks ride-through compliance, and maintains the load model the utility needs. Builds on 13.2 and 17.1; sits on DSX Exchange.

B2. Training Transient Smoothing and Storage Sizing Twin. Buyer: operator electrical engineering. Sizes rack capacitors, facility BESS and power burner settings against the utility's ramp rate agreement and the NVIDIA GB300 smoothing features, and simulates the grid-visible profile of a given workload mix. Builds on 10.4 and 12.2; sits on DSX Sim.

B3. Flexibility Commitment Manager. Buyer: operator, workload scheduling. The operator side of A5: receives utility flexibility calls, maps them to checkpointable training jobs, inference headroom, cooling and backup, guards the service level, and proves delivery. Builds on 12.4; sits on DSX Flex with Emerald AI as the reference.

B4. On-Site Generation and Microgrid Dispatch Optimizer. Buyer: operator, energy team. Co-optimizes turbines, reciprocating engines, fuel cells, batteries and grid draw against fuel, permits, emissions limits, utility signals and workload, for Abilene, Frontier, Cheyenne and Prometheus class campuses. Builds on 12.7, 11.4 and 10.4.

B5. Air Permit and Emissions Compliance Monitor for On-Site Power. Buyer: operator environmental, general counsel. Tracks run hours, emissions and permit limits per unit and flags exceedance before it becomes the next Memphis. Builds on 14.3.

B6. 800 VDC Electrical Safety and Protection Study Assistant. Buyer: operator electrical engineering, EPC. Manages arc flash, grounding and protection coordination for 800 VDC plants where the codes do not yet exist, assembling the authority having jurisdiction package. Builds on 2.5 and 3.3.

B7. Campus Electrical Digital Twin on Omniverse. Buyer: operator, EPC. The grid-to-chip twin, from the 34.5 kV or 13.8 kV utility interface through MV distribution and 800 VDC to the rack, for design, commissioning and operations. Builds on 19.26 and the Schneider, ETAP and Siemens work on the DSX blueprint.

B8. Powered Land and Site Selection Engine. Buyer: developer, infrastructure fund. Ranks candidate sites on time to power first, then fiber, water, tax, permits, community sentiment and utility tariff terms, using GridGLOBE as the substrate. Builds on 12.3 and 6.5.

Group C: Resource adequacy, markets and supply (extends Domains 11 and 20)

C1. Capacity Market Exposure and Hedge Advisor. Buyer: load-serving entity, trading. Models exposure to the PJM collar, its expiry, backstop procurement cost share, and bilateral hedges, by load class. Builds on 11.1 and 20.2.

C2. Deferred Retirement Economics and 202(c) Compliance. Buyer: generation fleet, regulatory. The cost, output, emissions and recovery of a plant kept online by order, with the litigation risk, for owners of Campbell, Eddystone, Centralia, Schahfer and Craig class units. Builds on 4.4 and 19.1.

C3. Turbine Slot and Long Lead Equipment Strategy. Buyer: generation development, supply chain. Values a slot reservation, an aeroderivative versus a frame, a reciprocating engine fleet or a fuel cell block against the load timeline, and tracks the backlog. Builds on 15.4 and 4.5.

C4. Gas-Electric Coordination Twin for Winter Events. Buyer: system operations, gas supply. Pipeline nominations, storage, firm transport and unit fuel status against the load forecast for a Fern class event, the unresolved item in the FERC-NERC report. Builds on 8.7 and 20.3.

C5. Interregional Transfer and Import Dependence Analyzer. Buyer: transmission planning. What MISO's 9 GW import in Fern means for planning, and what Pennsylvania's slide from 91 TWh of exports toward net import means for PJM states. Builds on 2.3 and 20.4.

C6. Bulk Power Equipment Provenance and Mitigation Program. Buyer: chief security officer, supply chain, NERC CIP. Inventories covered foreign equipment at 69 kV and above, inverters and storage included, against the August 26, 2026 order and the DOE rules due in December, and plans monitoring, mitigation or replacement. Builds on 13.1 and 15.4.

Group D: Affordability and the regulatory case (extends Domains 7 and 14)

D1. Large Load Cost and Benefit Attribution Engine. Buyer: regulatory, CFO. The defensible number: what large loads have added to and taken from residential rates for this utility, built to the standard of the PJM market monitor and EPRI findings, updated each rate cycle. Builds on 7.7 and 14.2.

D2. Ratepayer Protection Compliance Tracker. Buyer: regulatory. Proves, contract by contract, that the utility's large load terms meet the state's minimum bill, collateral, cost assignment and hold-harmless requirements and the July 2026 pledge. Builds on 14.3 and A2.

D3. Affordability Scenario Planner for Capital Plans. Buyer: CFO, planning. Tests a capital plan against bill impact by customer class and the political tolerance in the service territory, and re-sequences it. Builds on 5.3, 14.2 and 7.7.

D4. Arrears and Disconnection Prevention Engine. Buyer: customer operations. Predicts arrears and shutoff risk from interval and billing data and targets assistance before disconnection, the sharpened version of 7.3 for a period when winter heating costs are up 8.7 percent. Builds on 7.3 and 17.1.

Group E: Grid edge, extended (extends Domain 6)

E1. Minimum Demand and Negative Price Operations Manager. Buyer: distribution operations. The Australian problem: backfeed, voltage rise, export limits and dynamic operating envelopes for feeders heading toward zero net demand. Builds on 6.3 and 6.7.

E2. Flexible Load Interconnection Manager. Buyer: distribution planning, large customer group. The PG&E Flex Connect pattern for 2 to 20 MW loads: full capacity 90 percent of hours, curtailment less than 1 percent, energized in 4 to 8 months instead of 1 to 3 years, with graduation to firm service. Builds on 6.7 and 6.2.

E3. Bidirectional EV Fleet Capacity Valuation and Enrollment. Buyer: distribution planning, customer programs. Values V2G by vehicle and location using the E3 numbers, targets enrollment, and accredits the capacity, including school bus fleets. Builds on 6.5 and 6.8.

E4. Utility-Scale Merger Data Unification and Portfolio Due Diligence. Buyer: corporate development, IT. 15.6 and 15.7 rewritten for the NextEra-Dominion scale, with regulatory concentration analysis and divestiture remedy modeling. Builds on 15.6 and 15.7.

The six I would build first

If we can only fund six, these are the six, and the order matters.

A3, the Computational Load Reliability Compliance Twin, first. The FERC order of July 16 makes mandatory standards a matter of months, the NERC alert already imposes the studies, ERCOT's rule is in force, and PJM filed two days ago. Every utility with a data center on its system will need this in 2027 and the compliance evidence package is a pattern we already sell in 2.1. It is also the one product that both the utility and the operator will pay for, because B1 is the same data from the other side.

A1, the Queue Credibility Scorer, second. It is the first question every planning executive is being asked, the data to answer it is already in the utility's possession, and the answer changes the capital plan by billions. It is also cheap to build; it is a scoring model on a spreadsheet the utility already keeps, and it has to be simple enough for a planning VP to explain to a commissioner from memory.

A5 and B3 together, third, because flexibility is the supply. Whoever operates the flexibility contract between the utility and the data center owns the relationship, and the utility side of that contract does not exist as software. Building both sides on DSX Flex, with Emerald AI as the reference integration, puts us where NVIDIA is putting its own weight.

D1, the Cost and Benefit Attribution Engine, fourth. Affordability governs regulation now. The utility that can show its commission a defensible attribution wins the rate case and the data center contract; the one that cannot gets a moratorium. This is the piece that turns our regulatory domain from filing support into strategy.

C6, the Equipment Provenance Program, fifth. It is mandatory, it is dated, it touches every asset owner, and nobody is ready. It also opens the OT cybersecurity conversation, which is our weakest sales motion today.

B4, On-Site Generation and Microgrid Dispatch, sixth. More than 80 GW of on-site gas is designated for data centers, the campuses are being built as islands, and the operators are energy companies now whether they wanted to be or not. This is the first use case in the operator seat that a developer will buy on its own, and it is where our nuclear and generation experience carries over.

What I left out, and why

I left out anything that depends on SMR first power before 2032, on fusion, or on Order 2222 outside the ISOs where it is live, because I do not believe the timelines and I would rather not defend them in front of Dennis. I left out a general purpose data center energy management platform, because Schneider, Siemens, Vertiv and Eaton own that and NVIDIA is building the twin with them; our place is the grid interface and the utility relationship, not the building. I left out hydrogen entirely; four of seven hubs are cancelled and electrolyzer load has evaporated from utility forecasts. I left out a separate crypto use case; the miners are converting to AI and the large load framework covers them. I left out offshore wind analytics; the projects under construction survived their stop-work orders in court, the pipeline beyond them is frozen, and the buyer is not spending. And I left out anything that promises autonomous control of a utility or a data center, because Uptime's own survey says the operators do not want it and our framework is built on the opposite promise.

What this means for GridGLOBE and for how we sell

GridGLOBE now carries every utility in North America, EMEA and Australia with a point of view per region. The data center layer we are building next should carry, for each campus: owner, tenant, developer, IT and grid MW by phase, status, the serving utility and region, the power supply

arrangement (grid, on-site gas, fuel cells, PPA, nuclear, storage), the tariff class it sits under, the flexibility commitments in its contract where public, the electrical systems and vendors where public, water and cooling approach, and the permits and litigation attached to it. That layer, joined to the utility roster and the region points of view, is the visual argument for Group A and Group B, and it is the thing a Dennis-level reader can look at and understand in thirty seconds.

On the pitch, three changes. Lead with the three facts, not with the framework. Put flexibility in the first five minutes, because it is the only idea the utility, the developer, the ISO and the community all want to hear. And bring one number the utility has never seen about itself: its own queue credibility score, its own large load cost attribution, or its own ride-through exposure. That is the account-specific nuance the work gets judged on, and it is what a client cannot generate for themselves.

Sources and verification notes

The facts in this paper come from primary documents and reporting current to September 16, 2026. The principal sources by section are listed below. Items marked as contested or thinly sourced in the text should be verified against the primary record before they are quoted to a client; in particular the Palisades restart status, the exact count of unpermitted turbines at Colossus 2, the ERCOT queue figure on any given date, the EPRI finding on bill impact (which reached me through secondary reporting), and hyperscaler capital expenditure totals, which should be quoted as a range.

Load and forecasts: LBNL United States Data Center Energy Usage Report, June 2026 update; EPRI Powering Intelligence, February 26, 2026; NERC 2025 Long-Term Reliability Assessment, January 29, 2026; NERC 2026 Summer Reliability Assessment; Grid Strategies review of the 2025 LTRA (March 9, 2026) and National Load Growth Report (December 2025); EIA Short-Term Energy Outlook, September 9, 2026; PJM 2026 Load Forecast Report, January 14, 2026; Wood Mackenzie data center request analysis via Bloomberg, August 12, 2026; utility earnings coverage in Utility Dive for Dominion, AEP, Oncor, CenterPoint, Southern, Duke, Entergy, Xcel, Exelon, PG&E and Evergy, first and second quarters 2026; JLL H1 2026 North America data center report; CBRE H1 2026 North America Data Center Trends.

Projects: Epoch AI Stargate site tracker and AI data center directory; OpenAI announcements on Michigan and the five new sites; Vantage Frontier announcements; Entergy and Meta Hyperion filings and coverage; Global Energy Monitor Colossus 2 record; Earthjustice notice of intent, February 13, 2026; Microsoft Fairwater engineering post, November 12, 2025; Applied Digital investor releases; Google Clean Transition Tariff coverage, March 2026; Anthropic announcement of November 12, 2025.

Interconnection and tariffs: DOE directive to FERC, October 23, 2025; FERC show cause orders EL26-67 through EL26-72, June 18, 2026; FERC order on PJM co-location, EL25-49, December 18, 2025, and PJM's ER26-5181 filing of February 23, 2026; FERC approval of SPP HILL and HILLGA, January 14, 2026; ERCOT large load update to the Texas House, April 9, 2026; PUCT Projects 58479 through 58484; Governor Abbott directive of August 3, 2026; PUCO approval of the AEP Ohio tariff, July 9, 2025; Virginia SCC orders of January and August 5, 2026; Georgia PSC data center fact sheet, March 2026; EEI list of large customer projects and tariffs, August 2026; CoBank summary of the DELTa database.

Capacity and politics: PJM Base Residual Auction reports and releases for 2026/27, 2027/28 (December 17, 2025) and 2028/29 (July 14, 2026); PJM Independent Market Monitor findings as reported by PolitiFact and IEEFA; Pennsylvania PUC-commissioned PJM reliability study as reported September 2026; Pennsylvania Executive Order 2026-05, August 18, 2026; New York moratorium signed July 14, 2026;

MultiState state policy review, June 22, 2026; Data Center Watch Q1 2026 as reported by NBC News and Newsweek.

Supply side: Wood Mackenzie and SecondWatt turbine order and backlog compilations; Global Energy Monitor gas development report, January 2026; Bloom Energy releases and 2026 Data Center Power Report; Constellation and DOE releases on Crane; ANS coverage of Palisades and the federal site program; Power Engineering on Duane Arnold; pv magazine and POWER on transformer lead times; Latitude Media on batteries at data centers.

Flexibility and technology: Duke Nicholas Institute load flexibility study; EPRI DCFlex releases, February 2, 2026, and FlexMosaic framework; Google demand response announcements; Emerald AI and NVIDIA DSX Flex release, March 16, 2026; NVIDIA 800 VDC technical blogs and ecosystem announcement, October 13, 2025; NVIDIA Vera Rubin DSX release, March 16, 2026; NVIDIA GB300 power smoothing technical blog; OCP Diablo 400 specification; NERC incident review of the July 10, 2024 event; NERC Level 3 Alert, May 4, 2026; NERC reliability guideline on emerging large loads, May 2026; PUCT approval of NOGRR282 and NPRR1308, July 9, 2026; FERC order directing large load reliability standards, July 16, 2026; Uptime Institute 2026 Global Data Center Survey, July 28, 2026; Schneider Electric, Siemens, nVent and Eaton releases on AI factory reference architectures; SemiAnalysis on the 800 VDC transition.

Other trends: SEIA and Wood Mackenzie US Solar Market Insight Q2 2026; Sunrun earnings coverage; DOE VPP Liftoff 2025 update; PG&E SHARE announcement, September 10, 2026; SEPA VPP policy review Q1 2026; Illinois and New Jersey program approvals; E3 study for GM on bidirectional charging; AHRI shipment data; AEMO Quarterly Energy Dynamics Q2 2026; NESO connections reform releases; NextEra and Dominion merger release, May 18, 2026; Constellation releases on Calpine and the LS Power divestiture; FERC-NERC winter report, September 10, 2026; White House fact sheet on the bulk power system order, August 26, 2026; S&P Global and RRA rate case data; NEADA winter heating projection, September 14, 2026; Utility Dive coverage of BPA, MISO, EPRI Open Power AI Consortium, Santee Cooper and Fervo.