Powering the AI Data Center

A Developer's Guide to Grid Interconnection, Studies, Queues, Flexibility, Tariffs and Cost

Audience: Data center developers, site selectors, and their advisors

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Focus: US grid interconnection

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1. Executive summary

The rapid expansion of artificial intelligence is transforming electricity demand in the United States. Campuses requiring hundreds of megawatts—and increasingly gigawatts—are being developed where transmission capacity, generation availability, and reliability requirements can constrain energization. For developers, securing land and permits is not enough: a viable project must demonstrate when power can be delivered, which upgrades and studies are required, how energy and capacity will be supplied, and who bears the associated cost and risk.

Central finding. Grid access is no longer simply a physical connection problem. It is an integrated planning, regulatory, commercial, and risk-allocation challenge. The fastest credible path to power depends on solving transmission, resource adequacy, utility service, and site-specific engineering requirements together.

This guide provides a decision framework and evidence from PJM, ERCOT, SPP, MISO, CAISO, and vertically integrated utilities. It distinguishes adopted rules from proposed reforms and separates sourced facts from illustrative estimates. Regulatory status is dated 1 November 2026.

Five decisions for developers: (1) assess deliverable MW and credible energization dates, not just queue position; (2) choose physical supply independently of financial power hedges; (3) evaluate firm versus conditional service and curtailment capability; (4) quantify minimum bills, security, grid upgrades and exit exposure; and (5) validate UPS and load dynamic behavior before commissioning.

Grid access is the critical path

A gigawatt campus needs three to seven years to reach full load, mostly spent in studies, grid upgrades and the generation queue.

The rules were rewritten in 2025–2026

DOE directed FERC to act on large-load interconnection (RM26-4); FERC issued six show-cause orders on June 18, 2026.

NERC must file data center reliability standards by Dec. 31, 2026, and Texas adopted SB 6 rules.

Flexibility buys speed

- Accepting curtailment for about 85 hours a year could open 76 GW of grid headroom. ERCOT, SPP, PJM and CAISO offer or are building curtailable paths.

Federal rules cannot dictate curtailment of retail customers

- FERC rejected PJM's curtail-first plan in October 2026. Curtailment rules for retail data centers must come from the states.

Cost allocation is the political fault line

- Regulators are converging on take-or-pay terms: minimum demand charges, committed transmission revenue and security deposits.

Costs are up across the stack

- From 2025 to 2026, Lazard's average LCOE rose 18% for utility solar, 15% for gas combined cycle and 11% for onshore wind.
- A new combined-cycle plant that cost about $1,400/kW in 2023 now costs about $2,200/kW. Turbines head to $600/kW by 2027, three times 2019, with five-to-six-year lead times.

The detailed evidence and regional qualifications follow.

- Grid access is the critical path. A gigawatt campus may need approximately three to seven years to reach full load, and most of that time is in the study, upgrade and generation queue, not construction.
- Major rules changed or were proposed in 2025–2026. In that period:
  - DOE directed FERC to act on large-load interconnection (RM26-4).
  - FERC issued six show-cause orders on June 18, 2026.
  - FERC ordered NERC to write reliability standards for "computational load" by December 31, 2026.
  - Texas adopted SB 6 rules for loads of 75 MW and above.
  - SPP launched a conditional (interruptible) large-load transmission service.
  - PJM is building three new services for co-located load.
- Flexibility buys speed. A Duke study estimates the U.S. grid could absorb 76 GW of new load if that load accepts curtailment for 0.25% of its annual energy (about 85 hours a year). During 88% of those hours, half the load would keep running. Several major regions offer, or are developing, conditional or curtailable service options; these do not guarantee earlier energization at every location. ERCOT's controllable-load status, SPP's CHILLS, PJM's interim non-firm service and CAISO's proposed flexible services are examples.
- Federal transmission rules cannot generally prescribe retail curtailment priorities. FERC rejected PJM's Interim Resource Adequacy Service (curtail new large loads first) on October 9, 2026, because it set terms for retail customers, which is state jurisdiction. It rejected Tri-State's high-impact load tariff a year earlier for the same reason. Curtailment rules for retail data centers will come from states, as Texas has done.
- **Cost allocation is the political fault line.** Regulators are converging on take-or-pay contracts: minimum demand charges (Dominion GS-5: 85% for transmission and distribution, 60% for generation, 14 years), committed transmission revenue (PECO–Amazon), security deposits (Texas: $50,000 per MW), and ring-fenced generation affiliates (NIPSCO GenCo).
- **Costs are up across the stack.**
  - From 2025 to 2026, Lazard's average LCOE rose 18% for utility solar, 15% for gas combined cycle and 11% for onshore wind.
  - A typical new combined-cycle plant rose from about $1,400/kW for projects announced in 2021–2023 to about $2,200/kW for those announced in 2024–2025. Lazard's base assumption rose from $1,200–1,600/kW (2025) to $1,450–2,100/kW (2026).
  - Gas turbine prices are heading to about $600/kW by 2027, nearly three times their 2019 level, and a large turbine ordered today takes about five to six years to deliver.
- **Existing-plant deals shift the problem rather than remove it.** Diverting existing nuclear output to a data center can be structured to pay full transmission charges, as Talen and AWS now do. But it adds load without adding supply, which tightens capacity markets for everyone.

Reading guide. Chapters 2–4 establish the development and supply framework; Chapters 5–7 address flexible service, regional rules and precedents; Chapters 8–10 cover engineering and economics; Chapters 11–12 provide the risk register and developer implementation checklist. Regulatory status is time-sensitive: validate a docket before committing capital.

2. Why power is now the binding constraint

Before choosing a site or a supply model, it helps to understand why grid access now sets the schedule. This chapter covers the scale of today's campuses, the five gating items, and why regulators are stepping in.

2.1 Scale

Single campuses are now planned at utility scale. Examples include:

- Amazon in northern Indiana, ramping to 2,400 MW by 2032 [T26][S5].
- Meta's Hyperion campus in Louisiana, with 7.5 GW of new gas generation [S8].
- Stargate in Abilene, Texas, at 1.2 GW [S14].
- xAI's Memphis-area supercomputers, supplied by gas turbines across the state line in Southaven, Mississippi [S18].

NYISO alone reported 40+ load projects totaling over 10,000 MW in late 2025 [T29].

2.2 The five gating items

1. Land, zoning and water (months).
2. Utility or RTO study and agreements (one to four years).
3. Transmission and substation construction (two to five years, longer for new 345 kV or 500 kV lines).
4. Generation, if the developer brings its own (turbine lead times now around six years) [S10].
5. Commissioning, testing and ramp (staged over months to years).

Items 2 through 4 usually set the critical path.

2.3 Why regulators are intervening

- **Reliability.** Data centers can drop off the grid in seconds when a normal fault causes a brief voltage dip. Their UPS and power-conversion equipment switch to backup power, and the load disappears from the grid.
  - **July 10, 2024**: A fault on a 230 kV line in northern Virginia caused about 1,500 MW of data center load to switch to backup power. About 1,260 MW of that dropped after the third automatic reclose attempt and stayed off for hours. Customer-side controls caused the loss, not utility equipment [T36].
  - **April 18, 2026**: A similar fault in the same area cost only about 500 MW. NERC attributes the improvement partly to data centers changing their protection and control settings [S48].
  - **July 22, 2026**: A fault on a 230 kV line near Ashburn, Virginia, in Dominion's zone, was cleared normally. Even so, about 3,800 MW of data center load tripped offline in two waves, cutting PJM's total load by about 3.8%, from 99,984 MW to 96,205 MW.
    - PJM called it the largest such event in its history, more than twice the 2024 loss.
    - The sudden imbalance caused large voltage and frequency swings, and operators dispatched reactive power resources to bring voltage down. PJM restored its balance between supply and demand within nine minutes, inside NERC's 30-minute limit.
    - PJM's Operating Committee chair noted it was "a normally cleared fault" and that the loads "should not disconnect from the grid" [S49][S50].
    - NERC described the July event as nearly 4 GW and said the risk is "increasing rather than abating." The cause was still under analysis in September 2026 [S48].
  - **Texas**: ERCOT has analyzed 32 ride-through events of 100 MW or more between January 2023 and April 2026 [T36].
  - PJM is now considering ride-through requirements for computational loads. Its staff said, "You really need these requirements in place before the load comes on the system" [S49].

- **Cost shifting.** Existing customers fear paying for transmission and generation built for a few large loads.
- **Resource adequacy.** Large load additions erode reserve margins. PJM's Board has warned that if states do not allocate backstop procurement costs to new data centers, those costs could fall on other customers [T7].

3. Interconnection fundamentals

Connecting a large load works differently from connecting a generator. This chapter explains the three layers of agreements, the size thresholds that trigger new rules, the study stages and how queues are changing.

Developer perspective: a load can have an acceptable physical connection study yet still lack an executable service agreement, sufficient deliverable energy or capacity, or an approved retail tariff. Treat these as separate approval tracks, and identify which one determines the critical path.

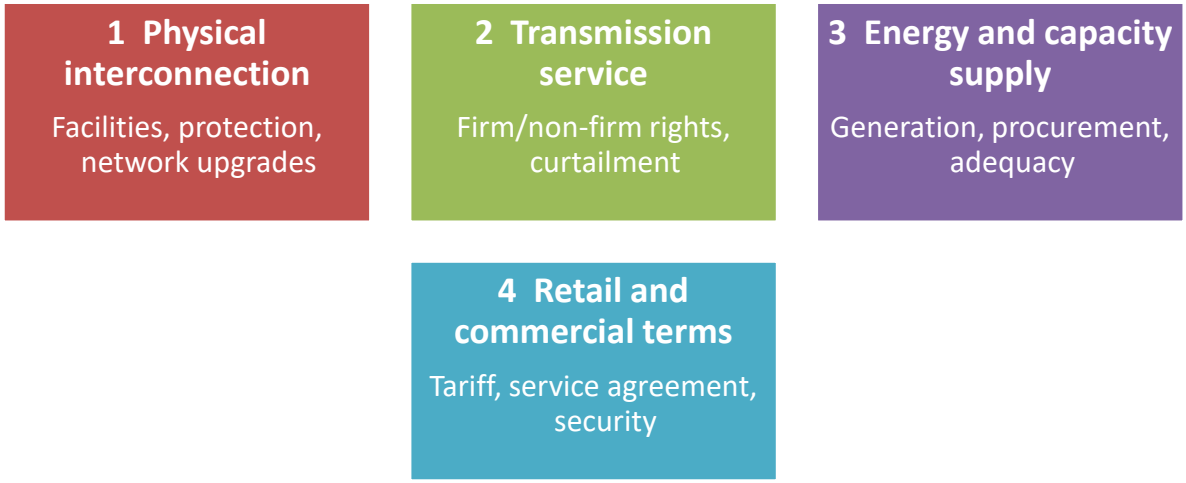


Figure 1. Four interacting requirements for energization; actual sequence and authority vary by region.

A positive electrical feasibility study does not itself establish a right to firm service or ensure sufficient generation. Confirm the physical point of interconnection, the applicable transmission-service arrangement, the source of energy and capacity, and the retail or wholesale contract. Ask the utility to identify the approval, payment and commissioning gate for each item.

3.1 Load interconnection versus generator interconnection

Dimension	Generator interconnection	Large-load interconnection
Flow	Injection	Withdrawal
Framework	Mature (Order 2003, Order 2023)	Utility-by-utility; being standardized in 2026
Key stability issue	Inertia, governor response	Ride-through, sudden load loss, oscillation, harmonics
Cost assignment	Generator pays upgrades	Disputed: direct assignment versus rolled into rates
Queue	Cluster studies with readiness deposits	Moving from first-come to batches and registries
Jurisdiction	FERC	Split: FERC (transmission service) and states (retail service)

3.2 The three layers of an interconnection

1. **Retail or wholesale service:** the rate schedule, special contract or PPA. Usually state-regulated for a retail data center.
2. **Transmission service:** network service (NITS), point-to-point, or new conditional and non-firm services. FERC-regulated.
3. **Physical interconnection:** the interconnection agreement, facilities and upgrade construction.

Much of the 2024–2026 litigation came from mixing these layers. The Talen–Amazon ISA tried to define how a load took service inside a generator's interconnection agreement. PJM's IRAS tried to set retail curtailment priority inside a FERC tariff. Both failed.

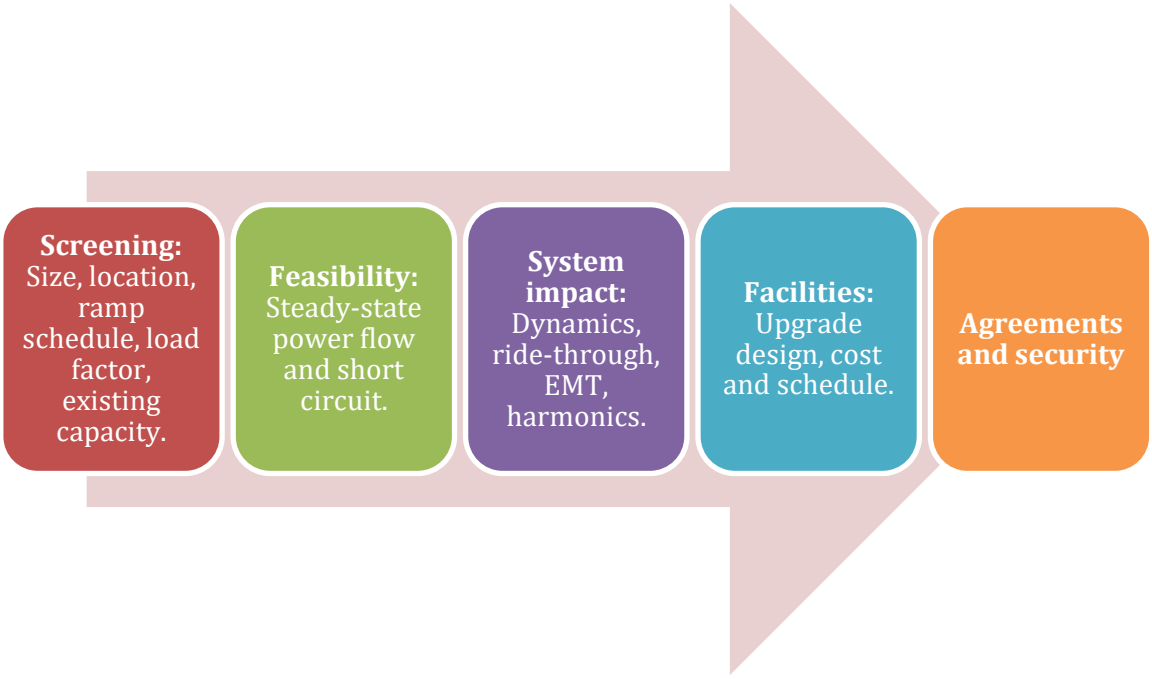
A related fourth consideration is resource adequacy: who is obligated to procure sufficient capacity, whether new supply is required, and how the cost of incremental capacity is allocated. Resource adequacy is closely linked to service but is not identical to the physical interconnection or transmission reservation.

3.3 Thresholds

Rule	Threshold
DOE ANOPR (RM26-4)	Over 20 MW [T29]
PJM large-load definition (accepted October 9, 2026)	50 MW or more at one point of interconnection [T3][S27]
CAISO proposal	50 MW [S19]
Texas SB 6 interconnection rule (16 TAC §25.194)	75 MW or more of new or expanded load at a site [T30]
ERCOT NPRR1234 (2024)	75 MW for interconnection requirements; 25 MW for modeling [T35]
Dominion GS-5	25 MW or more, 75% minimum load factor; new service from Jan. 1, 2027 [S11][S31]
PJM transmission owners' preferred threshold (ANOPR comments)	200 MW [T29]

3.4 Study stages (generic)

The five study stages are in figure below.



Chapter 8 covers the technical content of each study.

3.5 Queues: first-come, batch and registry

- **First-come, first-served** rewards speculative requests. PJM's Board, for example, now requires disclosure of duplicate load requests made to more than one utility, plus third-party review of load forecasts [T3].
- **Batch studies** evaluate all requests in a window together. ERCOT's Batch Zero is the leading example (Chapter 6).
- **Registries** create visibility without a separate queue. PJM's Board chose not to create a dedicated load queue. Instead, its large-load registry records each facility's location, ramp schedule and capacity supply [T3][S27].

- **Default assumptions matter.** Absent utility data, PJM assumes a three-year ramp and 70% utilization for forecasting [T3]. That is a useful benchmark for your own planning model.

3.6 How much large load is waiting to connect

Requests to connect large loads now far exceed what any region can serve, or what will ever be built. The gap between requests, accepted forecasts and signed contracts is the clearest sign of how speculative much of the queue is. It is also why regions are adopting batch studies, security deposits, registries and audits.

National picture

- **Five-year peak growth:** Grid Strategies forecasts U.S. peak demand rising 166 GW by 2030, from 829 GW to 995 GW, or 3.7% a year. Data centers account for about 90 GW of that growth. The firm considers the data center figure overstated by about 25 GW and puts a market-based estimate near 65 GW [S51].
- **Announced projects:** Investor-owned utilities report more than 39 GW of connected load from publicly announced large-load projects of 20 MW or more, representing about $840 billion of investment. Twenty states have approved at least one large-load tariff, and nine more are pending (EEI, March 2026) [T40].
- **Operating load:** NERC's survey for its Level 2 alert evaluated about 33 GW of operating data center load. It judged about three-quarters of the data center models insufficient for planning studies [T41].

By region

Region	Large-load requests or pipeline	What planners have accepted or forecast	Scale reference
ERCOT	About 474.7 GW of large-load requests (June 2026). 420.8 GW (90%) are data centers [S52][S53]. About 198 GW applied in Q1 2026 alone [S54]	About 205 GW eligible for Batch Zero on existing studies (preliminary, July 28, 2026) [S52]. Forecast growth +53.2 GW to 2030 (+62%) [S51]	Requests are about 5.5 times ERCOT's peak of roughly 86 GW *(calculated)* [S54]
PJM	Utilities submitted about 60 GW of large-load adjustments for the 2026 forecast [S55]	PJM accepted about 34 GW to 2030, a 43% cut. Large-load adjustments add 35.1 GW in 2026–2031 [S55]	Summer peak of 160 GW (2025), forecast to reach 253 GW by 2046 [S55]
Dominion (in PJM)	More than 48 GW of data center capacity in various stages of contracting (December 2025) [S56]	GS-5 take-or-pay terms apply to new agreements from 2027	—
SPP	About 26.4 GW of large-load requests (over 100 MW) since 2020, including 9 GW of data centers [S57]	About 7 GW (27%) reached executed service agreements [S57]. Forecast +24.2 GW to 2030 (+42%) [S51]	Peak of about 54 GW [S57]
MISO	About 55 GW of data centers tracked (analyst estimate) [S58]	MISO 2026 forecast: data center load from 1.2 GW (2026) to 20.5 GW by 2030 [S58]. Forecast +15.6 GW to 2030 (+12%) [S51]	Coincident peak of 124 GW, forecast to reach 184 GW by 2046 [S58]
Southeast	NiSource (Indiana, in MISO): about 4,920 MW across three hyperscale contracts by 2032 [S40]	Georgia Power +8.0 GW to 2030 (+45%). Duke Energy Carolinas +3.4 GW (+10%) [S51]	—
CAISO	PG&E data center pipeline of about 10 GW (2025) [S59]	CEC forecast: data center load +1.8 GW by 2030 and +4.9 GW by 2040 [S60]. CAISO +6.8 GW to 2030 (+15%) [S51]	—

What the numbers mean for developers

- **Most requests won't be built.** PJM cut utility submissions by 43%. In SPP only about a quarter of requests reached signed agreements. ERCOT's queue is several times its peak demand.
- **Speculative requests are being squeezed out.** Examples include Texas's $50,000/MW security at the interconnection-agreement stage [T30], PJM's disclosure of duplicate requests and third-party forecast review [T3], and Governor Abbott's August 3, 2026 order to audit every data center in ERCOT's queue. That order threatened to deny grid access to projects that don't disclose ownership, finances, water use and community impact [S53].
- **Position in a queue is not capacity.** What counts is acceptance into a planner's forecast, a firm allocation from a batch study, or a signed service agreement.
- **Expect forecasts to keep moving.** Grid Strategies notes that forecasts can mix up "2030 load" with "2030 in-service" capacity, and that correlated assumptions about realization rates can push forecasts too high [S51].

4. Power supply models

A developer must make three distinct choices: the physical source and delivery arrangement, the means of developing or procuring generation, and the financial or transmission-service overlay. The seven arrangements below remain useful practical building blocks, but they are not mutually exclusive alternatives. For example, a data center can use utility retail service, support a new wind facility with a vPPA, and contract separately for flexible load service.

Classification for decision-making. (A) Physical delivery models: utility or retail supply, bilateral physical supply delivered over the network, and co-located or islanded generation. (B) Generation-development choices: new build, uprate, or restart. (C) Financial and operating overlays: virtual PPAs, renewable certificates, storage, demand response, and non-firm or flexible grid service. These are not mutually exclusive alternatives; several can be combined.

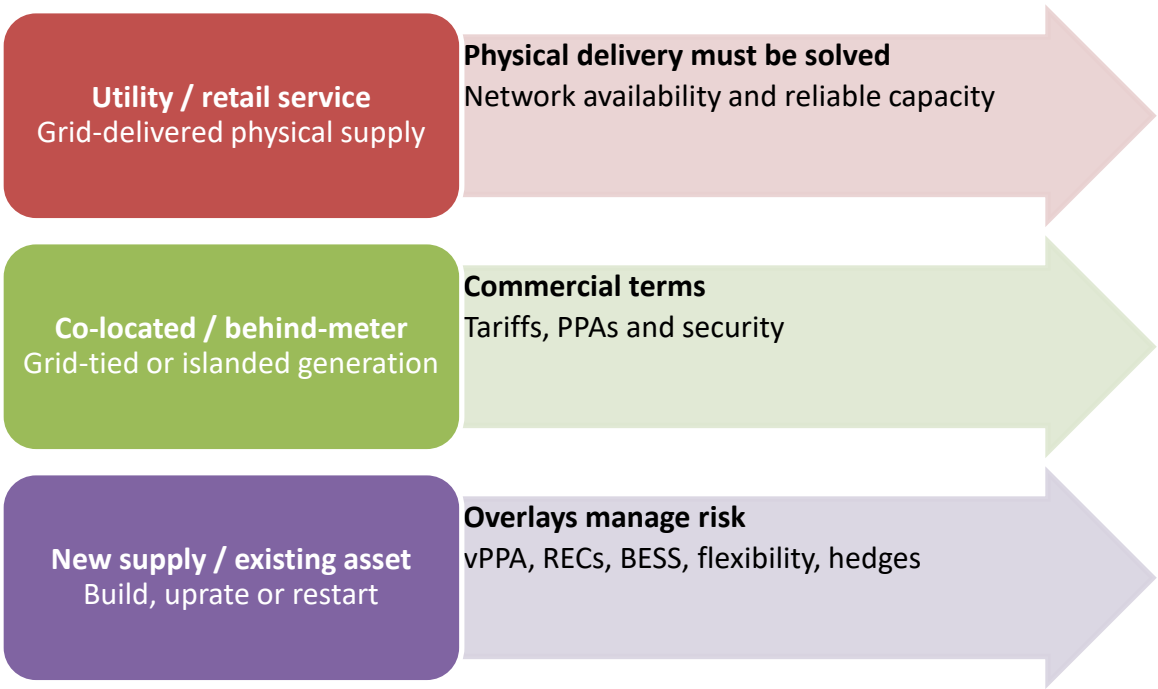


Figure 2. Physical power supply choices and contractual overlays are different dimensions of a project.

Classification: Models A, B and D primarily describe physical supply and delivery; Models E and F describe ways to develop additional generation; Model C is a financial hedge and renewable procurement instrument; Model G describes a service characteristic that can overlay several supply strategies.

4.1 Model A: Vertically integrated utility service

The utility plans, builds and owns generation and transmission and serves the data center under a tariff or special contract approved by the state commission.

- **Timeline:** two to five years, driven by the integrated resource plan (IRP), generation procurement and transmission construction.
- **Cost exposure:** minimum bills, exit fees, contribution in aid of construction.
- **Risk:** state approval and cost-shift challenges.
- **Examples:** Entergy Louisiana and Meta; Dominion GS-5.

4.2 Model B: Bilateral supply from a generator

The data center contracts for output from a specific generator, delivered over the grid.

Three variants:

- **Physical PPA with network delivery.** The load is billed as network load.
- **Utility affiliate generation company.** The affiliate builds dedicated generation and sells to the utility under a FERC-approved PPA. The utility serves the data center under a special contract. Example: NIPSCO GenCo [T26–T28].
- **Retail supplier model.** The generator's affiliate is the licensed retail supplier. Example: Talen and AWS since 2025 [S15].

Key terms are price, term, minimum take, termination payments, and who pays transmission and network upgrades.

A physical PPA identifies who sells energy and how it is delivered and settled. Its execution does not override load interconnection requirements or transmission constraints. An affiliated generation arrangement additionally requires scrutiny of affiliate transactions, cost allocation, and applicable retail and wholesale approvals.

4.3 Model C: Virtual PPA

A financial contract for differences on a renewable project's output, settled at the project's node or hub. The data center still buys physical power at retail.

- **Benefit:** renewable attributes and a price hedge, contracted in months.
- **Key risk:** basis (Section 9.1).
- **Note:** a vPPA does not shorten the interconnection timeline at all.

A virtual PPA is a financial settlement and potentially a renewable-development financing arrangement—not a physical supply route to the campus. Contracting a vPPA can support additional renewable generation, but does not, by itself, confer firm delivery, resource-adequacy credits, or a faster interconnection date.

4.4 Model D: Behind-the-meter and co-located generation

Generation on or next to the site serves the load directly, either islanded or with a grid tie.

- **Islanded or bridge gas:** Abilene and Southaven are examples [S14][S18].
- **Co-located with an existing plant:** Susquehanna under the rejected ISA; PJM's new co-location services.
- **Rules now in force in PJM:** co-located load can take firm contract-demand service for its gross demand minus dedicated generation, with non-firm backup limited to generator outages or derates. It cannot draw from the paired generator during curtailment [T4][T5].
- **Capacity rights:** an existing capacity resource must delist its capacity interconnection rights for the portion serving co-located load that does not take network service [T39].

4.5 Model E: Uprating existing generation

Adding capacity at an existing plant, such as a nuclear power uprate or gas turbine upgrade.

- **Strengths:** the cheapest incremental MW and an existing site.
- **Limits:** existing interconnection rights cap the uprate, and deliverability studies still apply.
- **Contrast:** uprating adds supply. Simply redirecting an existing plant's output to a new load does not (see Talen, Section 7.2).

4.6 Model F: Restarting retired generation

- **Main example:** Crane (Three Mile Island Unit 1).
- **Timing:** restart is gated by the NRC, plant condition and, critically, grid deliverability.
- **Rights transfer:** interconnection rights can be moved from another plant to accelerate a restart. FERC approved exactly this for Crane on June 1, 2026 [T25].

4.7 Model G: Flexible or curtailable grid service

A grid connection granted earlier, or larger, in exchange for accepting curtailment when the system is stressed. It can be combined with any model above. Chapter 5 covers it in detail.

4.8 Comparison

Model	Time to power	Adds new supply?	Main cost exposure	Main regulatory hook
A. Utility service	2–5 yrs	Usually yes	Minimum bills, exit fees	State commission
B. Bilateral PPA	1–6 yrs	Only if new plant	Price, take-or-pay, transmission	FERC (wholesale/transmission) and state
C. vPPA	Contract in months; asset 3–5 yrs	May support new renewable build; no physical delivery	Basis, settlement	Wholesale rules, tax credits
D. BTM / co-located	1.5–3 yrs (gas, if turbines available)	Yes, if new	Fuel, capex, air permits	RTO co-location rules
E. Uprate	2–4 yrs	Yes (incremental)	Capex; capped by rights	NRC / air permits; FERC
F. Restart	3–5+ yrs	Yes	Restart capex	NRC, FERC rights transfer
G. Flexible service	Can cut 1–4 yrs	No (uses existing headroom)	Curtailment, backup cost	RTO tariff (FERC) plus state retail rules

5. Flexibility and demand response: trading curtailment for speed

Allowing limited, measurable curtailment can facilitate earlier energization where adequate physical headroom exists and an applicable tariff authorizes conditional service. It does not remove all transmission, resource adequacy, or local reliability constraints. This chapter describes how flexibility is evaluated and what the developer must contractually commit to deliver.

5.1 Why flexibility shortens interconnection

Transmission and generation are sized for the peak hours of the year. A load that can step down during those few hours does not need the same upgrades to connect. The utility can connect it against existing headroom and add firm service later, when upgrades or new generation arrive.

How much headroom? The Duke Nicholas Institute's *Rethinking Load Growth* (February 2025) studied the 22 largest U.S. balancing authorities (about 95% of U.S. load) [S29]:

Annual curtailment (% of the new load's energy)	Curtailment hours/yr	New load absorbable (GW)
0.25%	85	76
0.5%	177	98 (regional: PJM 18, MISO 15, ERCOT 10, SPP 10, Southern 8)
1.0%	366	126

- **Average curtailment event length:** 1.7 hours at 0.25%, 2.1 hours at 0.5% and 2.5 hours at 1.0% [S29].
- **Depth:** in nearly 90% of curtailment hours, at least half the new load keeps running [S29].
- **Caveats:** the study excludes transmission constraints, which would reduce headroom, and reserve-margin capacity, which would increase it [S29].

Worked interpretation. For a constant 100 MW load, 0.25% of annual energy is 100 MW × 8,760 h × 0.0025 = 2,190 MWh. Spread over 85 curtailment hours, this corresponds to an average reduction of 25.8 MW (about 26% of load), not 85 hours of complete shutdown. The curtailment duration, depth, and energy percentage must be modeled separately.

Translating this into a developer's term sheet. The studied curtailment is mostly partial, roughly 20% to 50% of site load, and rare: tens to a few hundred hours a year. Curtailment of 20% to 30% of load during peak or emergency hours is in the range utilities and RTOs are designing services around. What the developer gives up is a share of energy well below 1%. What it gains can be years of earlier energization.

Decision test: compare the discounted value of earlier energization against the expected cost of curtailed computing, on-site generation or battery discharge, controls, compliance and the risk of longer-than-modeled interruptions. Use the specific tariff's event count, maximum duration, notification and performance requirements—not only the Duke national estimate.

Supply arrangement	Schedule driver	Principal exposure	Main qualification
Utility firm service	Grid upgrades / new generation	Minimum bills, network costs	Project- and utility-specific
New dedicated generation	Equipment and permits	EPC, fuel, delivery, financing	May improve adequacy; does not bypass grid
Behind-meter / co-located	Permits / controls / grid study	Backup, reliability, curtailment	Grid imports remain governed
Flexible / interim service	Service-rule availability	Curtailment, lost output, backup	Not always faster at every site
Financial vPPA	Contract execution	Basis and settlement	Does not shorten physical connection

Figure 3. Qualitative trade-offs; actual delivery dates, costs, and risk allocations require site-specific studies and tariffs.

Interpretation of the Duke study. Curtailment energy (% of annual MWh), event hours (hours with some reduction), and curtailment depth (% of MW reduced within an event) are not interchangeable. For a constant 100 MW load, 0.25% annual curtailment is 100 × 8,760 × 0.0025 = 2,190 MWh. If that occurs over 85 event hours, the average reduction is 25.8 MW, or 25.8% of site load—not 85 hours of complete disconnection. Transmission constraints and service design can materially change the realizable benefit.

5.2 How a data center provides flexibility

Method	Speed	Typical depth	Notes
Workload shifting (deferring training jobs, migrating to other sites)	Minutes	10–50%	Lowest cost; depends on the operator's software and fleet
On-site batteries / UPS	Seconds–minutes	Up to 100% for short periods	Battery energy limits duration; repeated events deplete it
On-site generation (engines, turbines, fuel cells)	Minutes	Up to 100%	Air permits often cap run hours; emissions and fuel cost
Cooling setpoint management	Minutes	5–15%	Limited by equipment thermal limits

A credible flexibility plan must show telemetry, response time and verification. PJM's interim service requires a five-minute response [T4]. ERCOT's withdrawal-limited private use network (WLPUN) must reduce withdrawal within one minute [S6].

Screening value of flexibility = value of earlier energization − expected curtailed output or workload cost − incremental backup fuel and wear − control, telemetry and compliance cost. This is a decision-screening identity, not a project valuation. Stress-test both more frequent curtailment and delayed conversion to firm service.

5.3 PJM: the curtail-first plan and why FERC rejected it

The design. In its Critical Issue Fast Path (CIFP) process, PJM's Board decided on January 16, 2026 [T3]:

- New large loads (50 MW or more) that do not bring new generation would be connected under a **connect-and-manage** framework.
- Their incremental demand would be **curtailed before pre-emergency demand response** in a capacity shortfall.
- Loads that bring new generation would get an Expedited Interconnection Track for that generation. That track covers projects over 250 MW of unforced capacity (UCAP) and offers:
  - a 10-month timeline,
  - full network-upgrade cost responsibility on the generator,
  - a $10,000/MW readiness deposit if paired with load,
  - a cap of 10 projects a year.

PJM then filed this design as the **Interim Resource Adequacy Service (IRAS)**, along with a 50 MW large-load definition and a large-load registry.

FERC's ruling (October 9, 2026). FERC accepted the definition and registry but rejected IRAS [S27]. Its reasons:

- Several provisions "appear to place obligations directly on eligible new large loads, which are, for the most part, retail customers."
- They "appear to dictate which retail customers taking retail service will be curtailed."
- The compensation framework "appears to establish a retail rate."
- IRAS intrudes on state jurisdiction over retail service and appears to discriminate against large loads.

The concurrence. Commissioner Rosner agreed that non-critical data centers should be curtailed before ordinary customers. But he said states should set curtailment priority, and curtailment should come only after voluntary demand response is exhausted [S27]. FERC "strongly encourage[s] states" to act [S27].

The precedent. FERC rejected Tri-State's High Impact Load tariff 3–0 on October 27, 2025, for the same reason. Tri-State had not shown that the tariff stayed out of retail service terms. FERC distinguished Tri-State's approved demand response program, which sets technical requirements for incentive payments rather than terms of retail sale [S28].

What this means for developers:

- In PJM, mandatory curtailment of retail data centers will come through state law or state-approved retail tariffs, not the RTO tariff.
- Ohio and Pennsylvania are the states analysts are watching [S27].
- Voluntary flexibility still works at the federal level. FERC-jurisdictional transmission services that are non-firm by design are permitted. These include PJM's Interim NITS for co-located load and SPP's CHILLS.

PJM's Interim NITS (co-located load). This is the surviving curtailable path in PJM:

- Non-firm, interruptible service until upgrades are in service, then conversion to full NITS.
- Curtailment comes before pre-emergency demand response, with a five-minute response requirement.
- PJM originally sought June 1, 2029 for the new services [T4][T5]. For Interim NITS it now proposes July 1, 2028, citing 18 to 24 months to automate tracking and curtailment of individual large loads, with a follow-on compliance filing in November 2026 [T6].

5.4 ERCOT: mandatory curtailment, paid demand reduction and controllable loads

Texas set retail rules directly through SB 6, which is why ERCOT can impose curtailment where PJM could not.

1. Curtailment during firm load shed (mandatory). The PUCT's proposed 16 TAC §25.521 (July 30, 2026) would require ERCOT to ensure that transmission-voltage large loads interconnected after December 31, 2025 can be curtailed during firm load shed. Curtailment equipment may be required before interconnection [T31].

2. Large Load Demand Management Service, LLDMS (voluntary, paid). The same proposal creates a competitively procured demand-reduction service for extreme-weather energy emergency (EEA) events [T31]:

Term	Proposed rule
Eligibility	Site of 75 MW or more of non-coincident peak demand; offers of at least 1 MW; must pass a price-responsiveness test
Notice	At least 24 hours before deployment
Payment	100% of clearing price when deployed; 25% when available but not deployed
Budget cap	$54 million per calendar year
Offer cap	Offers above $5,000/MWh rejected
Exclusivity	Not available to loads already in other ERCOT demand response, ancillary, firming or VECL programs
Enforcement	Payment clawback or suspension for non-performance

ERCOT's September 4, 2026 comments asked for:

- the availability payment to be set in its Protocols rather than fixed at 25%,
- a 12-month budget period rather than a calendar year,
- no deployment for transmission emergencies [T31].

Status: the tracker's record in Project 58482 ends with the September 2026 comments, and no adoption order was found. Treat the rule as proposed.

3. Curtailment conditions on co-located loads (Docket 59220). In its first net-metering case under SB 6 (July 24, 2026), the PUCT imposed tougher terms on a data center paired with existing generation than §25.521 proposes for grid-connected loads. The 260 MW site must fully disconnect within 30 minutes of an ERCOT instruction during a transmission emergency, without compensation, with at least 60 minutes' notice when practicable. The PUCT held that curtailment is not capped by the paired wind farm's output. Otherwise one co-located load could absorb behind-

the-meter generation that the grid needed while a neighboring load was curtailed. The site is also barred from ERCOT and utility demand response, ancillary services and Emergency Response Service. The PUCT treated the operating risks as a commercial trade-off the developer accepted in exchange for faster interconnection [S32].

4. Controllable load status in Batch Zero. A Batch Zero load can energize above its firm study allocation (its Low Power Consumption, LPC) by registering as a Provisional Controllable Load Resource (PCLR). A PCLR follows real-time dispatch (SCED) base points, is subject to bid caps and ramp-rate duties, and has no guarantee of full capacity in real time [S6][T35].

5. Withdrawal-limited private use network (WLPUN). This is "bring your own generation" in ERCOT. The study sets a fixed withdrawal limit. Energization is capped at that limit until the co-located generation is operating, and withdrawal must be reduced within one minute on instruction [S6][T35].

6. Pre-existing ERCOT demand response routes. These include controllable load resources providing ancillary services, Emergency Response Service, and avoiding transmission charges by cutting load during the four summer coincident peaks (4CP). PUCT staff has recommended replacing 4CP with 12CP using 30-minute intervals [T32]. That would reduce the payoff from 4CP avoidance and spread transmission cost across more months.

5.5 SPP: Conditional High Impact Large Load Service (CHILLS)

- **What it is:** long-term, non-firm transmission service for High Impact Large Loads. It lets them connect before network upgrades are complete or before enough designated resources exist [T13].
- **Terms:**
  - Available only from transfer capability left after firm service.
  - Subject to curtailment, interruption and load shed.
  - Term of up to seven years.
  - Requires supporting generation in commercial operation.
  - Charged at the zonal rate per kW of reserved capacity, with curtailment-hour rules [T13].
- **Status:** effective July 1, 2026. FERC accepted SPP's compliance filing on October 26, 2026 [T14].
- **Next step:** SPP's Price Adaptive Load (PALS) proposal is in stakeholder review [T15].

5.6 MISO, CAISO and the show-cause orders

- **MISO** plans to file two processes under Section 205 later in 2026 [T16]:
  - a Zero Injection Generator Interconnection Agreement (ZGIA) for co-located generation that does not export,
  - a Large Load Parallel Study Process.
- **CAISO** has not yet filed at FERC. Its August 12, 2026 straw proposal responds to the show-cause order with two flexible services [S19]:
  - **FILI (Flexible Interim Load Interconnection):** the load connects at a curtailable level while upgrades are built, then converts to firm service. Terms are tailored to each point of interconnection, with no cap on time or capacity.
  - **FLIP (Flexible Load Interconnection Permanent):** permanently flexible service. The load never funds or waits for firm-service upgrades. CAISO has asked stakeholders whether FLIP is worth pursuing.

  CAISO defines a large load as a single site with a peak of 50 MW or more. The schedule was a draft final proposal on September 21, a Board vote on October 28, and a Section 205 filing due November 16, 2026. The transmission owners (PG&E, SCE and SDG&E) must then file conforming tariffs [S19].
- **All six June 18, 2026 show-cause orders** list "new flexible-load services" as one of five reform areas [T8][T11].

The curtailment rules are compared in the Table below.

	Who can use it	Mandatory or voluntary	Status
PJM	Interim NITS: co-located loads only. IRAS: all new loads of 50 MW or more without new generation	IRAS was mandatory (curtail first); Interim NITS is elected	IRAS rejected Oct. 2026; Interim NITS proposed for July 2028
SPP (CHILLS)	Any High Impact Large Load, but supporting generation must be in commercial operation	Voluntary	In effect since July 1, 2026; up to 7 years
MISO	Co-located generation that doesn't export power, plus a parallel large-load study	Voluntary	To be filed later in 2026; nothing in effect
CAISO (FILI and FLIP)	Any load of 50 MW or more	Voluntary	Proposed; FERC filing due Nov. 16, 2026
ERCOT	Controllable load (PCLR): Batch Zero loads, to run above their firm allocation. WLPUN: loads paired with their own generation. Paid demand reduction (LLDMS): sites of 75 MW or more. Load-shed curtailment: transmission-voltage loads connected after Dec. 31, 2025	Mixed. PCLR, WLPUN and LLDMS are elected. Load-shed curtailment and net-metering conditions are mandatory	Batch Zero (incl. PCLR, WLPUN) approved June 18, 2026. Load-shed curtailment and LLDMS still proposed. Net-metering conditions imposed case by case (first order July 24, 2026)

5.7 Designing for flexibility: a checklist

1. Decide which workloads can be interrupted, and how fast.
2. Size batteries and backup generation for the depth and duration in the tariff, not just for outage backup.
3. Confirm air permits allow the run hours that curtailment would require.
4. Install telemetry and controls that meet the RTO's response time (one minute in ERCOT WLPUN; five minutes in PJM Interim NITS).
5. Price curtailment as lost revenue plus backup fuel and wear, and compare it with the value of earlier energization.
6. Negotiate the conversion date from non-firm to firm service, and what happens if upgrades slip.

6. Regional models

Each region answers the large-load question differently. This chapter summarizes the current rules, recent orders and what they mean for developers in PJM, Dominion, ERCOT, SPP, MISO, the Southeast and CAISO.

How to read the regional comparison. Load requests, planner-accepted forecasts, executed service agreements, and physically energized demand measure different stages. They must not be treated as interchangeable. In the regional tables, confirm each quoted MW value's definition, study year, and whether it represents gross demand, incremental demand, or committed capacity.

6.1 PJM

Structure. PJM runs the capacity, energy and transmission markets across 13 states and DC. It contains both restructured states (Pennsylvania, Ohio, Maryland, New Jersey) and vertically integrated utilities (Dominion in Virginia).

Co-location (EL25-49).

- **Feb. 20, 2025:** FERC opened a Section 206 show-cause proceeding [T29].
- **Dec. 18, 2025:** FERC found PJM's tariff unjust and unreasonable for lacking clear rates, terms and service options for co-location. It directed three new services: Interim NITS, Firm Contract Demand and Non-Firm Contract Demand. It also directed revised behind-the-meter generation rules and set a paper hearing on rates [T1][S2].
- **June 18, 2026:** FERC ruled on rehearing, compliance and the paper hearing [T2]. Rehearing of that order was deemed denied by operation of law on August 20, 2026 [T29].
- **Compliance:** PJM filed the Interim NITS compliance on August 17, 2026 (ER26-1479-002). It defends a July 1, 2028 effective date [T6].

Large-load integration (EL26-67).

- **June 18, 2026:** FERC found PJM's tariff preliminarily unjust and unreasonable for lacking clear rules on service to non-co-located large loads [T8]. The order covers study process, cost transparency, flexible-load services and proximate generation.
- **Aug. 14, 2026:** held in abeyance for 90 days [T9].
- **Sept. 21, 2026:** rehearing requests dismissed as premature. Responses are due November 16, 2026, unless replaced by Section 205 filings [T10].

Large-load definition and IRAS (ER26-3515). FERC accepted the 50 MW definition and registry and rejected IRAS on October 9, 2026 (Section 5.3) [S27].

Resource adequacy: the Reliability Backstop Procurement. PJM designed a centralized procurement to cover the capacity shortfall that large-load growth created [T7].

- **FERC's order (September 29, 2026; accession 20260929-3099).** FERC accepted the $555/MW-day offer cap (MW-weighted average) and the supplier collateral rules. It found the following potentially unjust and unreasonable, suspended execution for five months and told PJM to propose fixes [S33]:
  - the cost allocation, which did not show costs would follow the parties causing them,
  - the transmission-owner exit rules,
  - the collateral required of load-serving entities (Northern Virginia Electric Cooperative said it would have to post about $2 billion),
  - an opt-out for cooperatives and municipal utilities.

  Chairman Swett wrote that FERC "will not be forced into accepting a deeply flawed, eleventh-hour procurement mechanism" [S33]. PJM postponed the auction set to open September 30.
- **PJM's refiling (October 29, 2026)** [S34]:

- **Target:** 6,831 MW, the shortfall from the 2028/29 Base Residual Auction, less MW already covered by bilateral contracts between large loads and suppliers.
- **Price and term:** $555/MW-day cap; contracts of up to 15 years.
- **Schedule:** bid window March 1–28, 2027; results May 10, 2027.
- **Cost allocation:** by zone, in proportion to firm large-load growth between the actual summer 2026 peak and the 2028/29 forecast.
- **Exit and opt-out:** entities leaving PJM stay liable for the remaining term, and the cooperative/municipal opt-out is removed.

Why this matters to developers. Even where retail curtailment is off the table, large-load growth now carries an explicit capacity charge through the backstop, and contracting directly with new supply reduces it.

Transmission security agreements. PECO and Amazon: see Section 7.6.

Developer implications:

- Expect firm service to wait for upgrades. Interim non-firm service is the bridge.
- Bringing new generation earns the Expedited Interconnection Track, but the generator must exceed 250 MW of unforced capacity (UCAP), pay 100% of upgrades and post deposits [T3].
- Track Pennsylvania and Ohio for state-level curtailment rules.

6.2 Dominion Energy (Virginia)

Dominion is vertically integrated and regulated by the Virginia State Corporation Commission (SCC), inside PJM.

GS-5 rate class. The SCC created GS-5 in its final order of November 25, 2025, in Dominion's biennial review, Case No. PUR-2025-00058 [S11][S31]:

- **Who it applies to:** customers of 25 MW or more taking initial service and signing an Electric Service Agreement on or after January 1, 2027. Existing large customers are generally grandfathered.
- **Load factor:** minimum 75%.
- **Minimum charges (percent of contracted demand, billed monthly whatever the actual use):** distribution 85%, transmission 85%, generation 60%.
- **Term:** 14 years. A ramp of up to four years may sit inside the term, with a minimum annual ramp of 20%.
- **Reducing demand:** three years' notice, and the size of any reduction is limited.
- **Collateral:** required from customers without sufficient credit.
- **Exit:** a customer that ceases operations or defaults pays an exit fee covering the outstanding minimum charges for the remaining term.

The case number and terms come from a secondary summary of the order. Confirm against the SCC docket before relying on them. **[verify]**

Implication. GS-5 is the clearest take-or-pay template. Model the ramp years carefully (Section 9.5).

6.3 ERCOT (Texas)

ERCOT is an energy-only, single-state market with PUCT oversight. Texas' SB 6 (2025) drives a package of rules. ERCOT's report to the PUCT confirms that the Commission approved PGRR145 on June 18, 2026 [T35]. The July 9, 2026 open meeting approved NOGRR282 (ride-through), not Batch Zero [T34].

Rule	Status	Key terms
16 TAC §25.194: large-load interconnection (PURA §37.0561)	**Adopted Sept. 18, 2026** [T30]	Applies to new or expanded loads of 75 MW+ at a site. Standard large-load interconnection agreement (SLLIA). Security is the greater of $50,000/MW of contracted peak or allocated upgrade costs; $50,000/MW at the intermediate stage. 20% of security retained on withdrawal after allocation. Cash in a segregated interest-bearing account. Minimum billing demand must be acknowledged.
16 TAC §25.521: curtailment during load shed; LLDMS (PURA §39.170)	Proposed July 30, 2026 [T31]	See Section 5.4
Project 58484: transmission cost allocation	Staff draft report, 2026 [T32]	Replace 4CP with 12CP; end interconnection cost allowances for large loads; 10–15 year minimum demand charges for new large loads served by investor-owned utilities; implement by Dec. 31, 2026
Project 58479: net metering with existing generation (PURA §39.169)	ERCOT studies [T33]	Studies of co-location with existing plants: transmission security, resource adequacy, stranded transmission; possible curtailment and telemetry of gross load
PGRR145 / NPRR1325: Batch Zero	**PUCT approved PGRR145 June 18, 2026**	One-time system-wide batch study. Allocates transmission capacity in MW for Years 1–6. Base Load versus Studied Load. LPC firm cap. PCLR and WLPUN options. Refinement Study report due June 1, 2027 [S6]. (TAC May 19; ERCOT Board June 2) [T35][T30]. NPRR1325 recommended by the Protocol Revision Subcommittee May 6, 2026 (urgent) [T35]
Docket 59220: first net-metering case (PURA §39.169)	**Order July 24, 2026** [S32]	260 MW Crusoe/Ensign data center paired with the 265.5 MW Goodnight wind farm. Full disconnection within 30 minutes of an ERCOT instruction in a transmission emergency, uncompensated. Curtailment not capped by the paired generator's output. Barred from demand response and ancillary programs. Conditions reviewed after 36–60 months (Section 7.8)
NOGRR282: ride-through for large computational loads	**Effective Aug. 1, 2026**; PUCT approved July 9, 2026 [T34]	See Section 8.3

Developer implications:

- Budget $50,000/MW of security at the SLLIA stage. For a 500 MW campus that is $25 million.
- Decide early on Base Load, Studied Load, PCLR or WLPUN status.
- Design to the NOGRR282 ride-through curves now. Exemptions close for loads not energized by December 31, 2026.
- A move from 4CP to 12CP would change the value of peak-avoidance strategies.

6.4 SPP

- **HILL and HILLGA:** FERC unanimously approved SPP's High Impact Large Load study process and generation assessment in January 2026 [S20].
- **CHILLS:** conditional service effective July 1, 2026 (Section 5.5) [T13][T14].
- **SPP's own catalog of large-load routes** lists ERAS, the Provisional Load Process, HILL/HILLGA, CHILLS, the Peak Demand Assessment and CPP [T15].
- **Show-cause (EL26-68):** in abeyance until November 20, 2026 at SPP's and transmission owners' request [T12].

Implication. SPP offers one of the clearest curtailable paths, but CHILLS requires supporting generation in commercial operation [T13].

6.5 MISO

- **ERAS (Expedited Resource Addition Study):** a fast track for generation approved by FERC in 2025 and challenged in court [S21][S22]. NIPSCO GenCo's roughly 3,100 MW of gas and battery projects are in ERAS [T26].
- **Show-cause (EL26-70):** FERC asked MISO to keep network-upgrade costs on the load that causes them [T8]. MISO's July 20, 2026 report previews the ZGIA and the Large Load Parallel Study Process [T16].
- **Reliability requirements (ER26-3650):** MISO proposed Interconnection Reliability Requirements for Large Loads on August 28, 2026, covering visibility, ramp rate and ride-through. NERC and three Regional Entities intervened October 1, 2026 [T17].
- **State position:** the Organization of MISO States argued FERC should limit its role to the transmission study process and preserve state retail authority [T29].

6.6 The Southeast (Entergy, Southern, Duke, TVA)

The Southeast is vertically integrated and approves generation and special contracts through state commissions. TVA is federally owned.

- **Louisiana:**
  - The LPSC approved three Entergy gas plants for Meta in August 2025 [S17].
  - Meta later ordered 10 plants (7.5 GW), with seven requiring further approval as of March 2026 [S8].
  - FERC set an environmental review schedule on October 28, 2026 for ETC Tiger's Franklin Farms pipeline, built to supply gas for a new AI campus in Richland Parish served by Entergy Louisiana [T37].
- **Mississippi:** state permits for 41 xAI gas turbines in Southaven, March 2026 [S18].
- **Tennessee:** the NRC issued TVA the first U.S. BWRX-300 construction permit (Clinch River) in September 2026 [S24].

Implication. Engage in the IRP cycle early. Generation is planned years ahead, and new gas also needs pipeline capacity.

6.7 CAISO

- **Show-cause (EL26-71)** [T8].
- **CAISO's position:** CAISO supported a 20 MW threshold, coordinated load-generator studies, and study deposits with withdrawal penalties in its ANOPR comments [T29]. Its August 12, 2026 straw proposal offers two flexible services (FILI and FLIP) and a 50 MW single-site definition, with a FERC filing due November 16, 2026 (Section 5.6) [S19].
- **Policy environment:** state climate policy, retail rates and siting add constraints.

6.8 Summary

Region	Large-load threshold	Flexible / curtailable path	Firm-service rule	Status, Nov. 2026
PJM	50 MW	Interim NITS (co-located); IRAS rejected	Upgrades plus capacity; BYONG Expedited Track	Show-cause responses due Nov. 16
Dominion	25 MW+, 75% load factor	None specific	GS-5 take-or-pay (14 yrs)	Approved Nov. 2025; new service from Jan. 2027
ERCOT	75 MW	PCLR, WLPUN, LLDMS (proposed), load-shed curtailment (proposed), net-metering conditions	Batch Zero LPC; SLLIA with $50k/MW	§25.194 adopted; PGRR145 approved; §25.521 proposed
SPP	HILL criteria; confirm threshold under current tariff	CHILLS (up to 7 yrs)	HILL/HILLGA	CHILLS effective; show-cause Nov. 20
MISO	No single uniform threshold stated here	ZGIA, parallel study (to be filed)	ERAS for generation	ER26-3650 pending
Southeast	Special contracts	Utility DR programs	IRP build	Active approvals
CAISO	50 MW (proposed)	FILI and FLIP (proposed)	Large-loads initiative	FERC filing due Nov. 16

7. Precedents: approved, rejected and restructured

Recent deals show what regulators will and will not accept. This chapter walks through specific interconnections that were approved, rejected or restructured, and the reasoning behind each decision.

Case-study reading key. For each precedent, distinguish: (1) the applicant's proposed configuration; (2) the regulatory authority and procedural posture; (3) the precise outcome and grounds for decision; (4) outstanding approvals; and (5) what a developer can appropriately generalize. A one-off waiver or settlement is not an automatic entitlement for the next project.

7.1 NIPSCO GenCo and Amazon (Indiana): approved structure

Deal terms

- 15-year contract (dated September 18, 2025). Service starts January 1, 2027 and ramps to 2,400 MW by end-2032 [T26][S4][S5].
- Amazon has a one-time option, by March 31, 2029, to cut 1,200 MW [S5].

Generation

- GenCo builds about 3,000 MW: two 1.3 GW combined-cycle plants and a 400 MW, 4-hour battery [S5].
- GenCo's ERAS applications total about 3,100 MW of gas and battery, plus a separate 600 MW battery application [T26].
- Total investment is about $7 billion including transmission [S5].

Ring-fencing

- Costs sit in a separate business segment. Other customers are not responsible for the contract or the PPA [S4].
- About $1 billion of bill credits flow to other customers over the term [S5].

FERC filings

- GenCo applied for market-based rate authority (ER26-2909, June 22, 2026) [T26].
- NIPSCO and GenCo requested affiliate-sale authorization for the Amazon PPA (ER26-3474) and for a second PPA, dated April 16, 2026, serving Alphabet subsidiary Midnight Sun Ventures (ER26-3475). Both were filed August 3, 2026, asking for orders by October 2, 2026 [T27][T28].
- Their argument: the IURC-approved structure ring-fences captive customers, satisfying FERC's Edgar affiliate-abuse test.
- FERC's ruling was not found in the tracker or public sources. NiSource reports it began recording GenCo revenue in Q3 2026 [S39]. **[verify on FERC eLibrary]**

State approval. The IURC approved the Amazon settlement in Cause No. 46322 (order file dated June 17, 2026) [S4]:

- It found the settlement reasonable and in the public interest.
- It declined to require changes to the Amazon customer contract.
- It kept the 50/50 split of the shareholder-funded Customer Fund between host counties and other customers.

Three customers. NiSource now serves three hyperscalers under this model [S39][S40]:

- Amazon: up to 2,400 MW.
- Alphabet: an approved contract by August 2026.
- Microsoft: up to 788 MW from 2031, 20-year term, signed October 2026, pending IURC approval.

The three total about 4,920 MW at full ramp in 2032. That implies about 1,700 MW for Alphabet *(calculated)*. NiSource puts savings for existing customers at about $1.75 billion.

Opposition. Citizens Action Coalition opposed the deal for adding no renewables or efficiency [S5].

Lesson. A utility affiliate building dedicated generation, with a state-approved ring-fence and a FERC affiliate-sales showing, is the leading template for large loads in vertically integrated states. The second customer shows the template is being reused.

7.2 Talen and Amazon (Susquehanna, Pennsylvania): rejected, then restructured

What was filed. PJM filed an amended interconnection service agreement for the 2,520 MW Susquehanna plant (ER24-2172, June 3, 2024) [T20]. It would have:

- raised co-located data center load from 300 MW to 480 MW, rising to 960 MW once deliverability violations were fixed,
- treated the co-located load as "not Network Load,"
- shown $0 interconnection cost and $0 security.

What FERC decided

- **November 1, 2024:** FERC rejected the amendment. PJM had not met the high burden of showing the non-conforming provisions were *necessary*, because they mirrored PJM's generally applicable (and unapproved) co-location Guidance Document. Chairman Phillips dissented and Commissioner Christie concurred [T18].
- **April 10, 2025:** FERC denied rehearing. It clarified that the order does not bar future non-conforming agreements for generators serving co-located load, and Phillips dissented again [T19].
- **The signal:** co-location terms could not be adopted through one-off agreements. That led directly to the generic EL25-49 proceeding.

The cost issue behind the rejection. Under the proposed behind-the-meter design, Amazon's load would have been netted against the plant and excluded from network load. But it would still have relied on the grid for backup during plant outages, voltage support and frequency control. Transmission revenue requirements are fixed costs recovered across billed network load. Removing a large load from the billing basis while it still benefits from the system raises unit rates for everyone else. That cost-shift concern drove the debate, even though FERC's formal ground was procedural.

The restructured deal (June 2025) [S15]:

- 17 years through 2042, notional value $18 billion, up to 1,920 MW.
- Converted to a front-of-the-meter retail structure. Talen acts as AWS's licensed retail supplier, power is delivered over PPL's lines, and AWS pays all applicable transmission and distribution charges.
- Under the described front-of-meter retail structure, the previously proposed ISA amendment is no longer the vehicle for serving the load.

Does a cost problem remain?

- Transmission: largely resolved. AWS is now billed network load. Transmission revenue requirements are recovered by peak-load share, not by the MWh flowing over particular lines. Adding about 1.9 GW of billed load spreads fixed costs over a larger base, which can help avoid a revenue-base shortfall; the ultimate effect on other customers still depends on upgrades, allocations, and billing determinants.
- **What can still raise transmission cost for others:**
  - network upgrades caused by the load, if they are rolled into regional rates rather than assigned directly,
  - stranded cost if the load leaves early (hence PECO's committed-revenue agreement with Amazon, Section 7.6).
- Resource adequacy: the real remaining issue. The deal adds no generation. No uprate is involved. About 1.9 GW of existing nuclear output is committed to new demand, which can tighten PJM resource adequacy and place upward pressure on capacity and energy prices, depending on market response. PJM's market monitor

recommended that new data center load be required to bring its own new generation for this reason [T29]. PJM's backstop procurement and BYONG track are the market's responses [T3][T7].

Lesson. Co-location with existing generation is permitted if the load pays for grid services it uses. But regulators and markets will treat diversion of existing supply as a resource adequacy cost unless new supply is added.

7.3 Constellation and Microsoft (Crane / Three Mile Island Unit 1): restart in progress

- **The deal:** a 20-year PPA (2024). The plant shut in 2019 for economic reasons and is backed by a $1 billion DOE loan (November 2025) [S3].
- **Capacity:** 835 MWe per ANS [S3]. PJM queue filings describe the restart project at 859 MW [T23][T25].
- **Restart target:** 2027 [S3].
- **The grid problem:** PJM's filing shows Crane's full deliverability depends on 70 contingent reinforcements, with possible yearly interim studies through at least 2030 [T24]. Constellation said those contingent facilities could delay full deliverability to as late as December 2030 [T23].
- **The fix:** FERC granted a one-time waiver on June 1, 2026, letting Constellation transfer 760 MW of capacity interconnection rights from Eddystone Units 3 and 4 (380 MW each, kept running under DOE 202(c) emergency orders) to Crane. The transfer took effect at Decision Point II of Transition Cycle #2 and did not change Crane's queue position [T25]. PJM did not oppose, but asked that the waiver be limited to these facts and not presuppose its studies [T24].

Lesson. A restart is gated by deliverability, not just by the NRC. Transferring interconnection rights from a retiring unit is a proven, if one-off, accelerator.

7.4 Entergy Louisiana and Meta (Hyperion): approved, expanding

- **Initial approval:** three plants, approved by the LPSC in August 2025 [S17].
- **Expansion:** seven more gas plants, for 10 in total and roughly 7.4–7.5 GW. Wood Mackenzie describes the seven as combined-cycle units totaling 5.2 GW. Entergy also seeks 2.5 GW of solar and wind [S8][S35][S41].
- **Cost:** estimates for the expansion vary between sources: $21–22 billion and $27 billion [S41][S42].
- **Regulatory status:** on April 15, 2026 the LPSC voted 4–1 to fast-track the application [S41]. This was a procedural decision, not approval on the merits. Commissioner Lewis dissented, calling for an evidentiary hearing. A final vote is expected in December 2026 [S41][S42].
- **Conditions of the fast-track ("lightning") process** [S42]:
  - a letter from the state economic development agency confirming the project's importance,
  - the customer to cover more than half of infrastructure costs over a 15-year contract.

  Entergy says Meta's 20-year agreement covers "far more" than the required share, and puts statewide customer savings at $2 billion.
- **Disclosure and appeal:** in August 2026 the LPSC ruled that Meta may withhold certain data-center information. Advocates have appealed an LPSC decision as "arbitrary and capricious" [S43].
- **Gas supply:** the Franklin Farms pipeline review is underway [T37].
- **Criticism:** transparency and ratepayer exposure [S8][S43].

Lesson. Each expansion needs its own record. Fuel supply infrastructure is a separate federal approval.

7.5 xAI (Southaven, Mississippi): permitted on-site gas

- **Permit:** the Mississippi Permit Board approved 41 turbines in March 2026 over local opposition [S18].

Lesson. On-site gas at this scale is feasible but needs contested air permits. Those permits often limit run hours, which matters if the turbines are also meant to support curtailment.

7.6 PECO and Amazon (Falls Township, Pennsylvania): approved transmission security agreement

- **The agreement:** PECO filed a transmission security agreement (TSA) with Amazon Data Services for a new 230 kV campus served under PECO's retail tariff [T22]. It includes:
  - a committed revenue contribution toward PECO's transmission revenue requirement, owed whether or not the campus is built or runs as planned,
  - parent credit support from Amazon.com, Inc.,
  - early-termination fees,
  - shortfall true-ups,
  - a 365-day schedule-slip termination right.
- **FERC's ruling:** accepted November 21, 2025, effective November 23 [T21]. FERC:
  - applied the Mobile-Sierra presumption,
  - limited its finding to this agreement,
  - declined the market monitor's request to address PJM generation adequacy in the docket.

Lesson. Utilities in restructured states are using FERC-filed security agreements to protect transmission investment. Expect committed-revenue terms in any large PJM interconnection.

7.7 Stargate Abilene (Texas): bring your own generation

- **Campus:** 1.2 GW across eight buildings [S14]. Two buildings have been live since September 2025, with the rest ramping through 2026 [S37].
- **Supply:** on-site gas peaking plus a grid connection through Oncor in ERCOT, with grid power including local wind [S37][S38].
- **The 4.5 GW figure:** this is Crusoe's fleet-wide gas joint venture with Engine No. 1 (with seven GE Vernova turbines), not an Abilene-specific number [S14].
- **Not disclosed:** the on-site gas MW, turbine count and the ERCOT-approved grid MW for Abilene.
- **Expansion:** OpenAI's planned expansion toward about 2 GW was cancelled in March 2026. Microsoft then partnered with Crusoe on an adjacent 900 MW site [S37][S38].
- **Cost:** not disclosed.

Lesson. In ERCOT this configuration now falls under WLPUN rules and the net-metering studies (Project 58479).

7.8 Goodnight Wind and Crusoe (Texas): co-location approved with hard curtailment

- **The case:** the PUCT's first net-metering case under SB 6 (Docket 59220, order July 24, 2026) [S32]. It paired:
  - the 265.5 MW Goodnight wind farm,
  - Crusoe Load Two, a 260 MW AI data center in Armstrong County developed with Google, where Ensign Infrastructure replaced Crusoe as the customer in March 2026.
- **The PUCT's decision** [S32]:
  - It rejected the developers' proposal to limit curtailment in proportion to generation.
  - It held that emergency curtailment of co-located data centers "is not capped by the capacity of the paired" generator.
  - ERCOT's recommended cumulative curtailment obligation across the two adjacent loads is 525.5 MW.
- **Conditions** [S32]:
  - Full disconnection within 30 minutes of an ERCOT instruction during a transmission emergency, uncompensated.
  - No ERCOT or utility demand response, ancillary services or Emergency Response Service.

  - The wind farm must offer all available capacity to ERCOT dispatch.
  - The conditions run with the assets and bind successors.
  - The conditions come up for joint review after 36–60 months.
- **No hold-harmless proceeding:** ERCOT found no stranded transmission.

Lesson. In Texas, co-location with existing generation buys speed at the price of near-total curtailment exposure. Size backup and workload flexibility accordingly.

7.9 Rejections on jurisdiction: Tri-State (2025) and PJM IRAS (2026)

See Section 5.3. Both failed because a FERC tariff set terms of retail service.

7.10 Scorecard

Case	Outcome	Deciding factor
NIPSCO GenCo / Amazon	Approved (IURC); FERC affiliate sales pending	Ring-fenced affiliate generation; bill credits
Talen / Amazon ISA	Rejected (FERC 2024, rehearing 2025)	Non-conforming terms not shown “necessary”; load treated as non-network
Talen / AWS retail	Proceeding	Pays full T&D; resource adequacy concern remains
Crane rights transfer	Waiver granted (FERC June 2026)	Unique facts; contingent facilities
Entergy / Meta	Approved; expansion pending	State IRP and special contract
xAI Southaven	Air permit granted	State air permit
PECO / Amazon TSA	Accepted (FERC Nov. 2025)	Committed revenue; Mobile-Sierra
SPP CHILLS	Accepted (effective July 2026)	Voluntary non-firm transmission service
PJM IRAS	Rejected (FERC Oct. 2026)	Retail jurisdiction
Tri-State HIL tariff	Rejected (FERC Oct. 2025, 3–0)	Retail jurisdiction
PJM 50 MW definition and registry	Accepted (FERC Oct. 2026)	Information, not retail terms
ERCOT §25.194	Adopted (PUCT Sept. 2026)	State authority under SB 6
Goodnight / Crusoe net metering (Docket 59220)	Approved with conditions (PUCT July 2026)	Uncompensated 30-minute disconnection; curtailment not capped by generator
PJM backstop procurement	Partly accepted, suspended (FERC Sept. 2026); refiled Oct. 2026	Cost allocation, exit and collateral rules
Entergy / Meta expansion	Fast-tracked 4–1 (LPSC Apr. 2026); merits vote due Dec. 2026	Customer covers >50% of costs over 15 years
ERCOT NOGRR282 ride-through	Effective Aug. 2026	Reliability

8. Technical studies and reliability requirements for large loads

Large loads are evaluated through utility and regional studies, but not every study listed below is a separate, universally prescribed NERC requirement. Some are established engineering analyses, others arise from particular RTO or utility rules, and some are emerging standards. Confirm the applicable study scope with the serving utility and transmission planner.

The study inventory below is a practical planning checklist, not a claim that NERC mandates twelve separate named studies for every data center. Applicability depends on the system operator, utility, point of interconnection, equipment, and the status of evolving reliability standards. Distinguish currently enforceable obligations from planning guidelines, alerts, and draft requirements.

8.1 Where the standards stand

- **NERC Level 3 Alert (May 4, 2026).** Seven Essential Actions for registered planners and operators on computational loads [T36]:
  - modeling data,
  - contingency and stability studies,
  - commissioning tests,
  - protection settings,
  - dynamic fault recording,
  - operator communications.

  A Level 3 Alert carries no penalties, but NERC aggregates the responses and reports them to FERC. Entities are told to act before receiving a computational-load request [T36].
- **Project 2026-02 (May 14, 2026).** The standard authorization request (SAR) for a near-term standard and glossary terms ("Computational Load"), and a new registered-entity class [T36].
- FERC order (July 16, 2026, RD26-7). FERC directed NERC to file standards, glossary terms and Rules of Procedure revisions by December 31, 2026, and a work plan by March 1, 2027. Thresholds and technical values are left to NERC [S12][T36]. The cited statutory maximum penalty figure is $1,584,648 per violation per day; applicability depends on the enforceable requirement and entity [S12].
- **Registration.** NERC proposes new registered entities: Computational Load Owners and Computational Load Operators [T36]. NERC's petition to revise its Rules of Procedure for computational load was noticed by FERC in October 2026 [T38].
- **Draft SAR (August 26, 2026).** This draft from NERC's Large Loads Working Group covers ride-through, post-fault active power recovery (PFAPR), rate-of-change-of-frequency (RoCoF) withstand, and current consumption during disturbances. It cites events in Dominion, ERCOT and AEP territory and contemplates grandfathering existing sites [T36].
- **Regional rules already in force:** ERCOT NOGRR282 (Section 8.3); MISO's ER26-3650 proposal [T17].

Study categories: network adequacy (steady-state power flow and short circuit); dynamic performance (transient stability, voltage/frequency ride-through, multiple-fault sequences and EMT); power quality and protection (harmonics, relay coordination and large-load loss); operational readiness (telemetry, ramp and commissioning tests); and system/commercial adequacy (resource adequacy, facilities and upgrade-cost allocation). Request written acceptance criteria and vendor-validated models for each applicable item.

8.2 The study set

Study 1: Steady-state power flow. Thermal and voltage limits under normal and contingency conditions (N-1 and, where required, N-1-1).

- *Developer inputs:* MW and MVAr by phase of the ramp; power factor; point of interconnection.

- *Pitfall:* nameplate-only load cases oversize upgrades. Provide a staged ramp. PJM's default is three years at 70% utilization [T3].

Study 2: Short circuit. Fault duty for breakers, relays and grounding, including on-site generation contributions.

Study 3: Dynamic and transient stability. System response to faults and to sudden loss of large generation or load.

- *Developer inputs:* validated dynamic models of the load's power electronics and UPS. NERC's alert calls for modeling data in a standard format [T36].

Study 4: Single-event voltage and frequency ride-through. Whether the load stays connected through one disturbance, and how it recovers. Design against the applicable curve (Section 8.3).

Study 5: Multiple-fault (consecutive disturbance) ride-through. This is the study most often missing and the one tied directly to the largest event on record.

- *Why it matters*. In the July 10, 2024 event, about 1,260 of the 1,500 MW lost dropped after the **third** reclose attempt. Data center UPS systems counted repeated voltage disturbances, transferred to battery and stayed off for hours [T36]. The July 22, 2026 event (about 3.8 GW from a normally cleared fault) shows the problem is growing as more load connects.
- *What it simulates:*
  - the actual auto-reclose sequence at the serving and nearby substations (number of shots, dead times, fault duration on each attempt),
  - repeated voltage dips within a short window,
  - successive faults on parallel circuits during a storm.
- *What it checks:*
  - **Disturbance-counting logic** in UPS and power-conversion equipment. How many dips within what window trigger transfer to battery or generator? Does the logic latch?
  - **Battery state of charge** across the sequence. Does the UPS battery deplete before the grid stabilizes, forcing a transfer to generators?
  - **Post-fault active power recovery (PFAPR).** How quickly and smoothly does consumption return after each fault, and does a sudden return overload the system?
  - **Re-transfer and reconnection ramp.** If load does drop, is the return ramp-limited? NERC's incident review recommends ramp-rate terms for reconnection [T36].
  - **Interaction with utility protection.** Does the load's behavior change fault currents or voltage recovery in a way that affects reclosing success?
- *Method:* RMS dynamic simulation for the system-wide effect, verified with EMT simulation of the UPS and converter controls, using vendor-validated models.
- *Pass criteria:* the load rides through the specified sequence without transferring to backup, or transfers and returns in an orderly, ramp-limited way agreed with the transmission planner.
- *Design levers:* adjust UPS disturbance-counter thresholds and windows; set ride-through-compliant converter settings; size UPS batteries for the full sequence; coordinate with the utility's reclosing scheme (it can sometimes be modified at the serving station).

Study 6: Electromagnetic transient (EMT) analysis. Fast control interactions, sub-synchronous oscillation, and converter behavior that RMS models miss. ERCOT's 2024 large-load requirements already address sub-synchronous oscillation [T35].

Study 7: Harmonics and power quality. Distortion limits at the point of interconnection, and filter design.

Study 8: Protection coordination. Relay settings, and transfer-trip and remote-disconnect schemes. ERCOT's SB 6 rules contemplate curtailment equipment installed before interconnection [T31].

Study 9: Large-load loss and RoCoF. The system effect of the entire campus tripping. The NERC draft SAR targets RoCoF withstand [T36].

Study 10: Commissioning and ramp tests. Verification that the as-built facility matches its models. This is one of the seven Essential Actions [T36].

Study 11: Generation and resource adequacy. Whether the system can serve the load without eroding reserve margins. The show-cause orders required generation-adequacy reports [T8][T11].

Study 12: Facilities and cost allocation. The upgrade scope, cost, schedule and who pays.

8.3 ERCOT NOGRR282 ride-through curves (effective August 1, 2026)

The Texas rule establishes an adopted ride-through requirement for large computational loads [T34].

Frequency. Ride through frequency outside 58.8–61.2 Hz for 299 seconds within the bands 57.5–58.8 Hz and 61.2–63.0 Hz.

Voltage:

Voltage at POI (per unit)	Minimum ride-through time
0.90–1.10	Continuous
0.80–0.90	2.0 s
0.50–0.80	0.5 s
0.35–0.50	0.25 s
below 0.35	0.15 s

Transition. Before January 1, 2028, loads may reduce active power in proportion to the voltage drop between 0.8 and 0.5 p.u. After that date they must continue consuming in that band, with defined load-transfer options [T34].

Exemptions. Loads energized or with executed agreements by November 14, 2025 are exempt. The non-exempt path requires a utility (TDSP) attestation and initial energization by December 31, 2026 [T34].

Enforcement. A ride-through failure triggers a root-cause report within 90 days of ERCOT's request, a mitigation plan within 90 days after that, and implementation within 180 days. ERCOT may order disconnection if there is imminent risk [T34].

The curves are for single events. Multiple-fault performance (Study 5) is not separately specified, which is why it must be studied explicitly.

8.4 Typical durations

Phase	Studies	Duration
Screening	Power flow screen	1–3 months
Feasibility	Studies 1–2	3–6 months
System impact	Studies 3–9	6–12 months
Facilities	Studies 11–12	6–12 months
Commissioning	Study 10	At energization and each ramp step

ERCOT Batch Zero compresses the screening and feasibility phases into one system-wide study [S6].

9. Tariff methodology: basis, wheeling, security and PPA terms

Contract and tariff terms often matter as much as the energy price. This chapter covers basis, wheeling and transmission service, security requirements and the PPA terms worth negotiating.

For developers, distinguish physical transmission charges (the tariff for using the grid) from wholesale-price basis risk (the difference between financial settlement points). A physical supply contract, financial hedge, and utility tariff can each create separate payment streams. Peak-based transmission billing also varies by market; PJM and ERCOT examples are not a universal U.S. methodology.

9.1 Basis

Basis is the price difference between two grid locations, typically the generator's node and the load zone or hub. In a vPPA the data center pays or receives the strike price minus the generator-node price, while it pays the load-zone price for physical power. When the two diverge, the hedge fails. The worst cases come during congestion: high wind and low local prices at the project, with high prices at the load.

Mitigation:

- Settle at a liquid hub rather than at the project node.
- Choose projects in correlated zones.
- Model basis hour by hour rather than as an annual average.
- Negotiate basis caps or shared-basis terms.

9.2 Wheeling and transmission service

Moving power from a generator to a load uses someone else's transmission, and the load pays for that service.

Network service (NITS). The load is part of the utility's network and pays a share of the transmission revenue requirement based on its contribution to peak:

- the zonal coincident peak in PJM,
- 4CP in ERCOT today, with 12CP proposed [T32].

The revenue requirement is fixed. Adding billed load spreads it, and removing load from the billing basis concentrates it on others. That is the economics behind Talen (Section 7.2).

Point-to-point service. A reservation from one point to another, priced per MW reserved.

Non-firm and conditional services:

- PJM Interim NITS and Non-Firm Contract Demand [T4],
- SPP CHILLS, charged per kW of reserved capacity [T13].

Pricing and eligibility vary by tariff; conditional or non-firm arrangements introduce curtailment risk and do not automatically cost less overall.

Contract demand service (PJM co-location). Firm service sized to the load's gross demand minus its dedicated generation, with non-firm backup limited to generator outages or derates [T4][T5].

9.3 Security and cost protection

Mechanism	Example
Financial security per MW	Texas: greater of $50,000/MW or allocated upgrade cost; 20% retained if withdrawn after allocation [T30]
Committed transmission revenue	PECO–Amazon TSA [T21][T22]

Mechanism	Example
Minimum demand charges	Dominion GS-5: 85% T&D, 60% generation [S11]; PUCT staff: 10–15 year minimum demand charges [T32]; AEP Ohio Schedule DCT (approved July 9, 2025, Case 24-508-EL-ATA) [T29]
Ring-fenced generation	NIPSCO GenCo [S4][T26]
Readiness deposits	PJM Expedited Track: $10,000/MW if paired with load [T3]
Exit fees	GS-5; NIPSCO (some based on net book value) [S4][S11]
Schedule-slip rights	PECO TSA: 365-day schedule-slip termination right [T22]
Bill credits to others	NIPSCO: about $1 billion over 15 years [S5]

9.4 PPA and large-load contract terms

Term	What to negotiate	Benchmarks
Duration	Match to financing tenor	14 yrs (GS-5), 15 (NIPSCO–Amazon), 17 (Talen–AWS), 20 (Crane; NIPSCO–Microsoft) [S3][S5][S11][S15][S40]
Minimum take / take-or-pay	Level and ramp schedule	85% T&D and 60% generation (GS-5) [S11]
Ramp	Realistic MW by year	NIPSCO: Jan. 2027 start to 2,400 MW by end-2032 [S5]; GS-5: ramp up to 4 yrs, minimum 20% per year [S31]
Capacity reduction option	One-time step-down right	Amazon: 1,200 MW cut by Mar. 31, 2029 [S5]
Price escalation	Fixed versus indexed	Talen–AWS: 2% a year from 2028 [S15]
Early termination	Formula and decline over time	Remaining minimum charges (GS-5); net book value (NIPSCO) [S4][S11]
Curtailment	Depth, hours, notice, compensation	PJM Interim NITS 5-minute response [T4]; LLDMS 24-hour notice [T31]
Firm conversion	Date and remedy if upgrades slip	PJM Interim NITS converts to NITS when upgrades complete [T4]
Credit support	Form and amount	Parent guarantee (PECO TSA) [T22]; cash in a segregated account (Texas) [T30]
Change in law	Allocation of rule-change risk	Essential given pending show-cause outcomes
Disputes	Payment flow during disputes	NIPSCO PPA §8.6: utility relieved of paying GenCo while the customer disputes a bill [S4]

9.5 Worked example: minimum bill in a slow ramp year

A 300 MW contract under GS-5-style terms (85% T&D and 60% generation minimums) [S11]. Actual demand is 200 MW (67% of contract).

- **Generation minimum:** 60% × 300 = 180 MW. Actual demand exceeds it, so there is no shortfall.
- **T&D minimum:** 85% × 300 = 255 MW. The customer pays T&D on 255 MW, which is 55 MW (27%) more than it uses.

The lesson: contract the ramp, not the end state. Check whether minimums are applied monthly or annually in the actual tariff.

Illustrative billing consequence (not the GS-5 approved rate): if the T&D demand charge is assumed at $12/kW-month, paying for 55 MW of additional billing demand adds 55,000 kW × $12/kW-month = $660,000 per month, or $7.92 million over 12 months. Actual tariff rates, ratchets and staged contractual demand must be used in project underwriting.

10. The rise in cost

Several generation cost measures rose between 2025 and 2026, particularly capital costs and lead times for new gas generation. The changes are technology-, project- and metric-specific. This chapter compares planning LCOE assumptions, executed or quoted contract prices, and capital expenditure evidence without treating them as equivalent.

Developer cost lens. Distinguish (1) plant-level generation CAPEX and LCOE, (2) the cost of reliably delivering power to the meter—including transmission upgrades, losses, capacity, tariffs and backup—and (3) the full power-infrastructure contribution to data center project CAPEX. Plant LCOE alone is not the delivered cost of firm power.

This chapter separates three measures:

- **LCOE:** a lifetime cost per MWh, used for planning.
- **Contract prices (PPAs):** market evidence.
- **Capex:** what must be financed.

Lazard figures are unsubsidized. Cost-of-capital assumptions drive all of them.

The commercially relevant comparison is delivered, reliable power—not generation LCOE alone. Screen generation capital and fuel costs together with grid upgrades, capacity charges, backup and storage, retail demand charges, congestion/basis exposure, reliability and curtailment costs, and the timing of cash flow. The quoted values below include different data types (assumptions, reported project costs, contract indexes and forecasts) and should not be pooled without labeling their basis and vintage.

10.1 Lazard LCOE+ (July 2026, v19.0)

Technology	Range ($/MWh)	Avg ($/MWh)	Avg ($/kWh)
Solar PV, utility	40–98	69	0.069
Wind, onshore	37–99	68	0.068
Solar PV + storage	61–156	109	0.109
Wind + storage	49–140	95	0.095
Gas combined cycle	51–129	90	0.090
Gas peaking (open cycle)	144–276	210	0.210
Geothermal (illustrative)	67–111	89	0.089
Nuclear, new (Vogtle-based)	175–255	215	0.215

Source: [S7]. Nuclear is based on Vogtle 3 and 4.

10.2 Change in cost

2025 to 2026: Lazard's June 2025 edition (v18.0) compared with its July 2026 edition (v19.0) [S7][S44]:

Technology	2025 average ($/MWh)	2026 average ($/MWh)	Change
Utility solar	58	69	+18%
Gas combined cycle	~78 (implied)	90	+15%
Onshore wind	~61 (implied)	68	+11%
Gas peaking	~200 (implied)	210	+5%

The percentage changes are Lazard's own labels in the 2026 edition. The 2025 solar average ($58/MWh, range $38–78) is from published coverage of the June 2025 edition [S44]; the other 2025 averages are back-calculated from Lazard's percentages. Lazard called new combined-cycle cost a "10-year high" in 2025 [S45] and a "15-year high" in 2026 [S46].

Contract prices since 2024. LevelTen's North American solar index was $61.67/MWh in Q4 2025, about 9% above Q4 2024. Wind was $73.77/MWh, with no year-over-year change reported [S9]. LevelTen cites Section 232 tariffs, foreign-entity-of-concern (FEOC) rules and federal permitting delays as cost drivers [S9].

Against 2024, the clean comparison is contract prices: LevelTen solar PPAs rose about 9% from Q4 2024 to Q4 2025. Lazard's comparison is 2025 to 2026.

10.3 Gas: combined cycle and open cycle

- **CCGT capex, 2025 vs 2026 (Lazard):** Lazard's base assumption rose by about a quarter in one year, while its high case was unchanged [S7][S45].

	June 2025 edition	July 2026 edition	Change
Base capital cost	$1,200–1,600/kW	$1,450–2,100/kW	Low end +21%, high end +31%; midpoint $1,400 → $1,775/kW (+27%)
High-case quotes (early-stage, post-2028 operation)	$2,400–2,600/kW	$2,400–2,600/kW	Unchanged

The high case was already in Lazard's 2025 edition. What moved in 2026 is the base assumption, which is catching up with market quotes. Lazard says its figures have not yet reached recently observed quotes [S7].

- **Actual projects show the jump more sharply** (GridLab, September 2025) [S47]:

Announced	Projects ($/kW)	Typical range
2021–2023	Entergy Texas OCAPS $1,300; LG&E Mill Creek 5 $1,427	~$1,300–1,430/kW
2024	Entergy Legend $2,125; Evergy McNew $2,255; Muscatine CHP $2,165; East Kentucky Cooper $1,768	~$1,770–2,255/kW
2025	Duke Cayuga $2,256; Homer City $2,222; LG&E Mill Creek 6 $2,194; KU Brown 12 $2,144	~$2,140–2,260/kW

A typical new combined-cycle plant rose from about $1,400/kW for projects announced before 2024 to about $2,200/kW for those announced in 2024–2025, roughly +55% (calculated).

- **Turbines:** prices are projected to reach about $600/kW by end-2027, up 195% from about $203/kW in 2019 (Wood Mackenzie, April 2026; 2019 figure calculated) [S35]. None of the sources gives a 2024 or 2025 turbine price.
  - Turbines are 20–30% of CCGT project cost, and more for simple cycle [S10].
  - Lead times: a large turbine ordered now takes about five years to deliver (EPRI), up to six years by some accounts, with order books sold through 2027. Before the 2024 surge, large-turbine lead times were typically two to three years (industry experience, not from these sources). Small turbines take 18–36 months [S35][S10].
  - Global orders were 110 GW at end-2025, against 60–70 GW a year of manufacturing capacity [S10].
  - Slot reservation fees are now charged: KU/LG&E paid GE Vernova $25 million to reserve a turbine for 2030 operation. A new combined-cycle plant ordered in 2025 often cannot come online before 2030–2031 [S47].*(calculated)*.
- **Cross-check *(estimate)*:** $600/kW ÷ 20–30% implies $2,000–3,000/kW for a full CCGT, consistent with Lazard's high case.
- **Open cycle:** $144–276/MWh. Valuable as firm capacity and backup, expensive as energy [S7].

10.4 Storage: capex versus LCOS

These are different measures and should not be mixed.

Capex is the installed cost to build. Lazard's 2026 assumptions for utility-scale storage, including the inverter [S7]:

System	Capex ($/kWh)	Equivalent ($/kW) *(calculated)*
100 MW, 4-hour (400 MWh)	270–365	1,080–1,460
100 MW, 2-hour (200 MWh)	270–580	540–1,160

LCOS is the lifetime cost per MWh *discharged*, including charging energy. It is the cost of shifting energy in time and should not be compared directly with a generator's LCOE.

System	LCOS range ($/MWh)	Average
100 MW, 4-hour	210–292	251
100 MW, 2-hour	215–414	315

Why Lazard's LCOS looks high [S7]:

1. **Charging energy** is included at $40/MWh with 2% escalation. At about 89% round-trip efficiency, that alone is about $45–52 of every discharged MWh.
2. **Low throughput:** one cycle a day, 350 days a year, at 90% depth of discharge, which is about 315 full cycles a year.
3. **Financing:** 80% equity at 12% and 20% debt at 8%.
4. **O&M, warranty and augmentation:** $3.75–7.75/kWh-yr of O&M, plus warranty of 0.66–1.85% of capex from year 3, plus augmentation to hold capacity.

Why 80% equity, and what changes at 70% debt and an 8% cost of capital? Lazard applies the same equity-heavy capital structure across technologies for comparability, and it is typical of merchant project finance. A storage asset with a long-term contract, or one owned by a utility, can usually carry 60–70% debt. To test your case, I rebuilt the 4-hour LCOS in a simplified pre-tax model *(estimate)*:

Financing case	Simplified LCOS ($/MWh)	Change
Lazard structure (pre-tax WACC 11.2%)	175–242 (mid 208)	Base
70% debt / 30% equity, WACC 8%	154–214 (mid 183)	−12%
WACC 7%	148–206	−15%

The simplified model omits taxes and depreciation, so it runs about $35–50 below Lazard's published figures. Applying the same 12% reduction to Lazard's range gives roughly **$185–255/MWh** for contracted, debt-financed storage *(estimate)*.

Financing matters, but it is not the main driver. Charging energy (about $50 of every MWh) and the number of cycles are larger levers.

For a data center, storage is usually bought for capacity, ride-through and curtailment response, not for daily arbitrage. Its value is better measured in $/kW-year of firm capacity than in $/MWh shifted.

Hybrid assumptions. Lazard's solar-plus-storage and wind-plus-storage figures assume [S7]:

- 100 MW of generation plus 50 MW / 200 MWh of 4-hour storage (storage at 50% of generation capacity),
- storage capex of $270–365/kWh and charging cost of $40/MWh,
- synergy credits of 10% of storage capex and 25% of inverter cost.

A data center seeking near-firm supply would need far more storage, or another resource, so treat these hybrid LCOEs as partially firmed energy, not firm power.

10.5 Fuel cells (solid oxide, e.g., Bloom)

- **Contracts:**
  - The AEP–Bloom agreement (February 2026) was reported at $2.65 billion, without capacity, term or structure [S13].
  - Oracle's master agreement covers up to 2.8 GW, with 1.2 GW firm [S13].
- **Data quality:** the version 1 figures of $6,640/kW and $58/MWh came from a single analyst source and are withdrawn.
  - The $6,640/kW was derived from a backlog value that probably includes long-term service revenue, not just equipment.
  - The $58/MWh is inconsistent with any plausible capex: fuel alone costs about $21–34/MWh.
  - Lazard's 2026 edition does not cover fuel cells [S7].

Rebuilt estimate *(estimate)*. Assumptions: 95% capacity factor, 8% cost of capital, a heat rate of about 6,900 Btu/kWh (roughly 50% efficiency on a higher-heating-value basis), and O&M including stack replacement of $10–30/MWh.

Installed cost	Life	Capital ($/MWh)	Fuel at $3–5/MMBtu	O&M	LCOE ($/MWh)
$3,000/kW	20 yrs	37	21–34	10–30	**67–101**
$4,000/kW	20 yrs	49	21–34	10–30	**80–113**
$6,640/kW	20 yrs	81	21–34	10–30	**112–146**
$6,640/kW	15 yrs	93	21–34	10–30	**124–158**

Interpretation. At realistic installed costs, fuel cells run about $80–150/MWh, above a CCGT ($90 average) and well below open-cycle peaking ($210). Their case rests on speed to power, modularity and permitting (low local emissions), not cost. Ask vendors for firm $/kW capex, stack-replacement schedules and guaranteed heat rate.

10.6 Geothermal

- **Lazard illustrative:** $67–111/MWh [S7].
- **Fervo–Google:** a 396 MW enhanced-geothermal PPA for Utah data centers, the largest of its kind, with the price undisclosed [S23].

Use Lazard's range for planning and request indicative pricing.

10.7 Small modular reactors

- **Permit:** the NRC issued TVA the first U.S. BWRX-300 construction permit, for Clinch River, on or about September 29, 2026 [S24][S36].
- **Cost:** TVA "has not put a price on the project," and has no cost-sharing agreement yet. It says it "continues negotiations with industry partners" [S36]. One unsourced report of $5.4 billion could not be traced to TVA and is not used.
- **Reference point:** Lazard's new-nuclear range ($175–255/MWh) is based on large-reactor experience (Vogtle) [S7].

Treat SMRs as a 2030s option with first-of-a-kind cost risk.

10.8 Planning summary

Resource	$/kWh	Basis
Solar PV	0.040–0.098	Lazard LCOE
Onshore wind	0.037–0.099	Lazard LCOE
Solar + storage (50% / 4 h)	0.061–0.156	Lazard LCOE
Wind + storage (50% / 4 h)	0.049–0.140	Lazard LCOE
CCGT	0.051–0.129	Lazard LCOE
Open-cycle gas	0.144–0.276	Lazard LCOE
Geothermal	0.067–0.111	Lazard (illustrative)
New nuclear	0.175–0.255	Lazard (Vogtle-based)
Fuel cell	0.08–0.15	Calculated *(estimate)*
Storage (4 h), per kWh shifted	0.210–0.292 (Lazard); ~0.185–0.255 at 8% WACC	Lazard LCOS; *(estimate)*
Solar PPA (NA, Q4 2025)	0.0617	LevelTen
Wind PPA (NA, Q4 2025)	0.0738	LevelTen

Developer interpretation. Assign each risk an owner, probability/impact estimate, earliest detection point, mitigation deadline, and contractual remedy. A generic High/Medium label is useful for screening but should be recalibrated to the project, utility territory and schedule.

11. Risk register

This register lists the main schedule and cost risks for a large-load project, with their likelihood, impact and practical mitigation.

Risk	Likelihood	Impact	Mitigation
Grid deliverability later than plant or energization date (e.g., Crane contingent facilities to 2030)	High	High	Model the deliverability date; secure interim or non-firm service; consider rights transfers
Firm upgrades slip while on non-firm service	High	High	Contract a firm-conversion date and remedies; size backup for longer curtailment
Curtailment deeper or more frequent than modeled	Medium	High	Stress-test 1% and 2% curtailment cases; check air-permit run hours
State curtailment rules imposed after connection (post-IRAS)	Medium–High	Medium	Track PA, OH, VA and TX rulemakings; change-in-law clauses
Ride-through non-compliance (single or multiple fault)	Medium	High	Run Study 5; set UPS counters; vendor-validated EMT models
Potential NERC registration and standards (Dec. 2026 filing)	High	Medium	Evaluate whether registration as a Computational Load Owner or Operator; budget compliance
Security and minimum bills in slow ramp	High	Medium	Contract the ramp; negotiate step-down options
Turbine and EPC price escalation	High	High	Reserve slots early; fixed-price EPC; consider aeroderivatives, engines or fuel cells
Basis divergence (vPPA)	Medium	Medium–High	Hub settlement; basis caps
Resource adequacy cost allocation (backstop procurement)	High	Medium–High	Bring new generation; expect state cost-allocation rules
Air permit and community opposition	Medium	High	Early engagement; lower-emission technologies
Show-cause outcomes change study rules mid-process	High	Medium	Monitor responses due Nov. 16 and 20, 2026

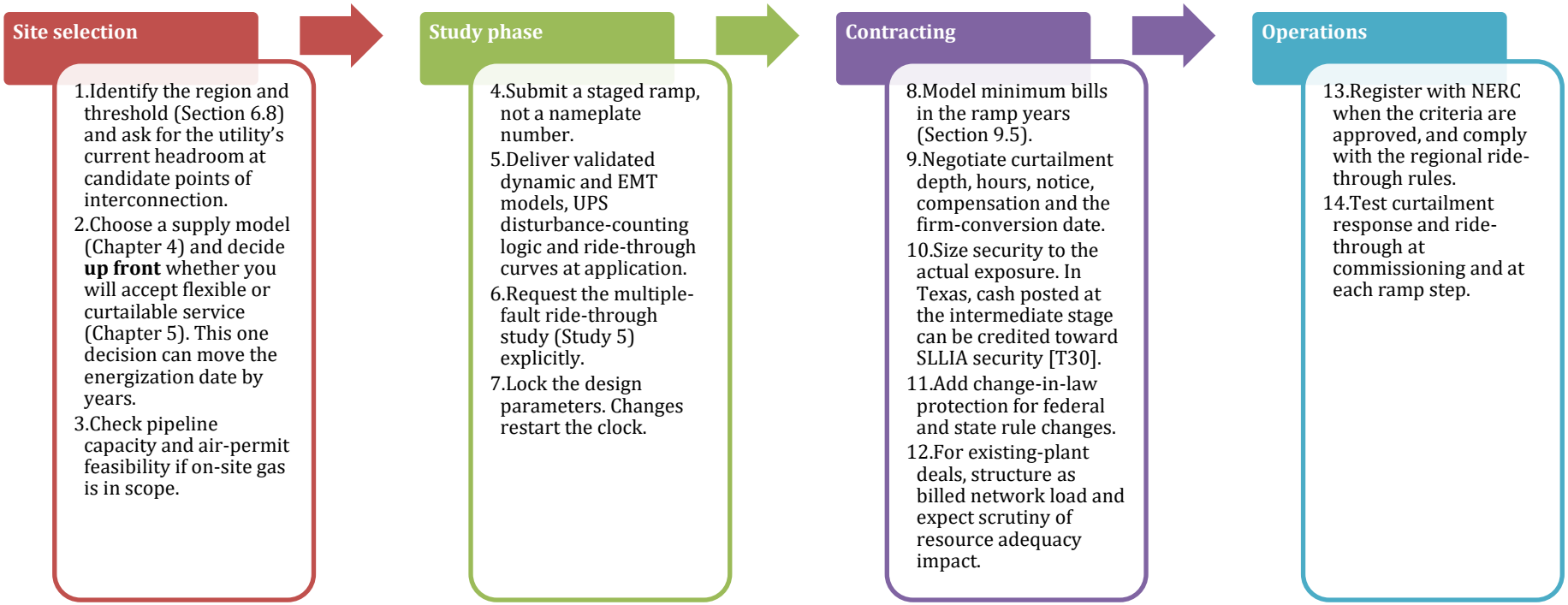
Stage-gated execution roadmap: Gate 1—site and credible POI capacity; Gate 2—power delivery model and utility feasibility; Gate 3—study completeness, dynamic models and deposits; Gate 4—facility scope, cost allocation and firm/non-firm rights; Gate 5—tariff and PPA contract exposure; Gate 6—construction, protection tests and phased energization; Gate 7—operating telemetry and ongoing compliance. At each gate, document a named decision-maker, written utility evidence, budget exposure, and a no-go criterion.

Recommended deliverables to maintain throughout development: an MW/MVAr load and ramp schedule; one-line diagram; POI option register; study and permitting schedule; contract/security ledger; firm-service conversion assumptions; curtailment and backup dispatch plan; UPS/converter validated model inventory; and an integrated critical-path schedule.

12. Developer's playbook

This chapter turns the guide into a step-by-step checklist, from site selection through study, contracting and operations.

Use this checklist as a stage-gate tool: do not commit irrevocably to land, construction, or generation procurement until the project has a credible, documented path through utility studies, service agreements, permits, funding security, and a phased MW ramp. The right evidence is an executable agreement and technical capacity—not merely a queue position or an indicative utility letter.



13. Glossary

- **4CP / 12CP:** Transmission cost allocation based on the four summer (or twelve monthly) coincident peaks.
- **BYONG:** Bring Your Own New Generation (PJM).
- **CHILLS:** Conditional High Impact Large Load Service (SPP).
- **CIFP:** Critical Issue Fast Path (PJM stakeholder process).
- **CIR:** Capacity Interconnection Rights (PJM).
- **EMT:** Electromagnetic transient (simulation).
- **ERAS:** Expedited Resource Addition Study (MISO, SPP).
- **HILL / HILLGA:** High Impact Large Load / Generation Assessment (SPP).
- **Interim NITS:** Non-firm, interruptible network service for co-located load until upgrades are complete (PJM).
- **IRAS:** Interim Resource Adequacy Service (PJM proposal, rejected October 2026).
- **LCOE / LCOS:** Levelized cost of energy / of storage.
- **LLDMS:** Large Load Demand Management Service (Texas, proposed).
- **LPC / MPC:** Low / Maximum Power Consumption (ERCOT Batch Zero).
- **NITS:** Network Integration Transmission Service.
- **PCLR:** Provisional Controllable Load Resource (ERCOT).
- **PFAPR:** Post-fault active power recovery.
- **RoCoF:** Rate of change of frequency.
- **SLLIA:** Standard Large Load Interconnection Agreement (Texas).
- **TSA:** Transmission Security Agreement.
- **WLPUN:** Withdrawal-Limited Private Use Network (ERCOT; “bring your own generation”).
- **ZGIA:** Zero Injection Generator Interconnection Agreement (MISO, planned).

14. Timeline

Date	Event	Ref
Jun 3, 2024	PJM files amended Susquehanna ISA (300 to 480 MW co-located)	T20
Jul 10, 2024	About 1,500 MW data center load loss in the Eastern Interconnection	T36
Nov 1, 2024	FERC rejects Susquehanna ISA amendment	T18
Feb 11, 2025	Duke “Rethinking Load Growth” published	S29
Feb 20, 2025	FERC opens PJM co-location show-cause (EL25-49)	T29
Apr 10, 2025	FERC denies rehearing on Susquehanna	T19
Jun 2025	Talen–AWS front-of-meter retail PPA (1,920 MW to 2042)	S15
Jul 9, 2025	AEP Ohio data center tariff approved (PUCO)	T29
Aug 2025	LPSC approves three Entergy plants for Meta	S17
Oct 27, 2025	DOE Section 403 letter; FERC opens RM26-4. FERC rejects Tri-State HIL tariff (3–0)	T29, S28
Nov 21, 2025	FERC accepts PECO–Amazon TSA	T21
Nov 25, 2025	Virginia SCC final order creating Dominion GS-5 (PUR-2025-00058)	S31
Dec 18, 2025	FERC orders three PJM co-location services	T1
Jan 2026	FERC approves SPP HILL and HILLGA	S20
Jan 16, 2026	PJM Board: 50 MW definition, connect-and-manage, BYONG track	T3
Feb 10, 2026	SPP files CHILLS	T13
Mar 2026	Mississippi permits 41 xAI turbines; Meta orders 10 plants	S18, S8
Apr 15, 2026	LPSC fast-tracks Entergy’s seven-plant Meta expansion (4–1)	S41
Apr 16, 2026	FERC notice of intent on RM26-4	T29
May 4, 2026	NERC Level 3 Alert on computational load	T36
Jun 1, 2026	FERC grants Crane CIR transfer waiver	T25
Jun 18, 2026	FERC six show-cause orders; EL25-49 rehearing/compliance order. PGRR145 approval (per §25.194 order)	T2, T8, T11, T30
Jul 1, 2026	SPP CHILLS effective	T14
Jul 9, 2026	PUCT approves NOGRR282	T34
Jul 16, 2026	FERC orders NERC computational load standards (RD26-7)	S12
Jul 22, 2026	About 3,800 MW data center load trips in Dominion zone, the largest in PJM history	S49
Jul 24, 2026	PUCT order in first SB 6 net-metering case (Goodnight / Crusoe)	S32
Jul 30, 2026	PUCT proposes §25.521 (load-shed curtailment, LLDMS)	T31
Aug 1, 2026	NOGRR282 ride-through effective	T34
Aug 3, 2026	NIPSCO/GenCo affiliate-sale filings (Amazon, Alphabet)	T27, T28
Aug 12, 2026	CAISO straw proposal (FILI, FLIP, 50 MW)	S19
Aug 14, 2026	PJM and SPP show-cause proceedings put in abeyance	T9, T12
Aug 17, 2026	PJM Interim NITS compliance filing	T6
Aug 28, 2026	MISO large-load reliability requirements (ER26-3650)	T17
Sep 18, 2026	PUCT adopts §25.194 (SB 6 interconnection)	T30
Sep 29, 2026	NRC permits TVA BWRX-300. FERC partly accepts and suspends PJM backstop procurement	S24, S33
Oct 2026	NIPSCO signs Microsoft (788 MW, 20 yrs)	S40
Oct 9, 2026	FERC accepts PJM 50 MW definition and registry; rejects IRAS	S27
Oct 26, 2026	FERC accepts SPP CHILLS compliance	T14
Oct 28, 2026	FERC sets Franklin Farms pipeline EA schedule	T37
Oct 29, 2026	PJM refiles 6,831 MW backstop (bids Mar. 1–28, 2027)	S34
Nov 16, 2026	PJM and CAISO show-cause responses due	T10, S19
Nov 20, 2026	SPP show-cause abeyance ends	T12
Dec 2026	LPSC merits vote on Entergy / Meta expansion expected	S41
Dec 31, 2026	NERC standards and registry filing due; NOGRR282 exemption path closes; PUCT 12CP target	S12, T34, T32

Date	Event	Ref
Jan 1, 2027	Dominion GS-5 applies to new service agreements	S31
Jan 1, 2027	NIPSCO–Amazon service begins	S5
Mar 1, 2027	NERC work plan filing	S12
May 10, 2027	PJM backstop procurement results	S34
Jun 1, 2027	ERCOT Batch Zero Refinement Study report	S6
Jul 1, 2028	PJM Interim NITS proposed effective date	T6
Mar 31, 2029	Amazon capacity-reduction option deadline (NIPSCO)	S5
Jun 1, 2029	PJM contract-demand services target date	T4
Dec 2030	Possible Crane full deliverability, absent CIR transfer	T23

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Appendix A: Verification status (updated 1 November 2026)

#	Item	Status	Finding
1	FERC ruling on NIPSCO affiliate sales (ER26-3474/3475)	**Open**	No order found. Alphabet contract approved at state level; Microsoft (788 MW) added Oct. 2026 [S39][S40]
2	Abilene gas share and grid MW	**Partly resolved**	4.5 GW is Crusoe's fleet-wide JV; site uses on-site gas peaking plus an Oncor grid tie; MW undisclosed [S14][S37]
3	Entergy–Meta expansion	**Resolved: pending**	Fast-tracked 4–1 on Apr. 15, 2026; merits vote expected Dec. 2026 [S41][S42]