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Data Center Design, Resilience, Reliability and Sustainability

Power, Cooling, Redundancy and Cost for 100–300 MW Campuses, with a Virginia Reference Design Applied Nationwide and Globally

Which combination of grid service, onsite generation, storage and cooling gives a 100–300 MW campus the best resilience and regulatory fit before 2030, tested in Dominion Energy Virginia's territory and applied across nine U.S. regions and seventeen international markets

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ABSTRACT

This paper asks which combination of grid service, onsite generation, storage and cooling gives a 100–300 MW data center campus the best resilience and regulatory fit for energization before 2030. It uses Dominion Energy Virginia's territory and a Henrico County reference site as the test case, then applies the result across nine U.S. regions and seventeen international markets. The method combines a review of grid-operator, regulator and company documents current to October 2026, engineering estimates for a 200 MW reference design, and a cost model published with the paper. The governing judgment is that electricity supply, not water, limits new capacity in Virginia and in most other markets examined; water use is set by the cooling design, and direct-to-chip liquid cooling with closed-loop dry heat rejection takes process water out of the siting question in temperate climates. The configuration designed to meet the proposed ride-through rules, ride out a winter gas event or a grid outage, and qualify as a synthetic minor air source is firm utility service, a grid-forming battery, dual-fuel reciprocating engines limited to outages and emergencies, and warm-water liquid cooling. On a common UPS and ride-through baseline, with the grid bill built from Dominion's tariff sheets, it models at $34–35/MWh, about $69 million a year, above grid-only service with diesel backup; the difference buys outage endurance and grid-forming transfer, not energy. Zoning, air permits and tariff rules, not equipment, decide what onsite generation may do. Nuclear and geothermal supply are not available to a Virginia campus this decade.

KEYWORDS

data centers; electricity interconnection; capacity markets; PJM; ride-through; onsite generation; liquid cooling; water use

JEL CLASSIFICATION

L94 (Electric Utilities); L86 (Information and Internet Services; Computer Software); Q41 (Energy: Demand and Supply; Prices); Q48 (Energy: Government Policy); Q25 (Water); K32 (Energy, Environmental, Health, and Safety Law); R52 (Land Use and Other Regulations)

SCOPE

Sanctir working paper · Version 1.1, October 24, 2026 (version 1.0: October 12, 2026). The cost model's workbook and script are published with the paper, together with the tariff input file, the 41-station design-conditions table, the station manifest and the hour-count script. AI assistance was used for source retrieval, citation checking and technical review; every accepted finding was checked by the author against the cited source, and the record is in Appendix B. This is not peer review and the paper has not had practitioner review. Section 15 lists what must be replaced before the paper supports a filing, a contract or an investment decision. License: CC BY-NC-ND 4.0.

IF YOU READ NOTHING ELSE

The binding constraint	In Virginia and in most of the other markets examined here, electricity supply is the binding constraint on data center development. Water use depends mainly on the cooling design chosen for each site, although water service, discharge and fire-protection supply remain site requirements under any design. Direct-to-chip liquid cooling with closed-loop dry heat rejection takes process water out of the siting question in temperate climates.
Why it matters now	PJM has cleared three straight capacity auctions at the price cap, and the last two fell short of the reliability requirement. PJM has proposed ride-through requirements for loads of 50 MW or more, which would apply to projects entering PJM studies on or after January 16, 2027. Zoning, air permits and tariff rules, not equipment, decide what onsite generation may do, and nuclear and geothermal supply are not available to a Virginia campus this decade.
What the configuration costs	The configuration designed to meet the proposed ride-through rules, ride out a winter gas event or a grid outage, and qualify as a synthetic minor air source is firm utility service, a grid-forming battery, dual-fuel reciprocating engines limited to outages and emergencies, and warm-water liquid cooling. On a common UPS and ride-through baseline, with the grid bill built from Dominion's tariff sheets, it models at $34–35/MWh, about $69 million a year, above grid-only service with diesel backup; the difference buys outage endurance and grid-forming transfer, not energy.

1 Executive summary

In Virginia and in most of the other markets examined here, electricity supply is the binding constraint on data center development. Water use depends mainly on the cooling design chosen for each site, although water service, discharge and fire-protection supply remain site requirements under any design. That is the central finding of this paper.

PJM capacity is short. PJM, the regional grid operator, has cleared three straight capacity auctions at the price cap. The last two fell short of the reliability requirement: 6,623 MW for 2027/28 and 6,831 MW for 2028/29. The 2028/29 auction added only 525 MW of new generation. PJM's own results show demand growing faster than supply.

Contracted capacity is not actual load. Dominion has about 54 GW of data center capacity under contract. Its data center billing peak in August 2026 was 4.8 GW, about one-eleventh of the contracted figure. Dominion's own forecast of coincident demand expects 9,880 MW by 2032 and 19,466 MW by 2047, less than two-fifths of the contracted total even at the end of the forecast.

Water is small statewide and specific locally. JLARC, the General Assembly's audit agency, found data center water use sustainable and under 0.5% of state withdrawals. One 300 MW campus on evaporative

cooling would draw about 3.4 million gallons a day. That matters to a local utility on a peak summer day. The same campus on closed-loop dry cooling draws almost none. Whether water limits a project depends on the site and the cooling design, not on statewide totals.

Grid stability rules are coming. PJM has proposed ride-through requirements for loads of 50 MW or more. Covered loads would have to stay connected through defined voltage and frequency dips and return to 90% of demand within 2 seconds. The proposal would apply to projects entering PJM studies on or after January 16, 2027. It is a proposal, not yet a rule. A campus designed today should meet it anyway. Virginia's 2026 demand-flexibility statute (Va. Code § 56-596.7) makes carbon-emitting generation ineligible for the utility flexibility programs due in 2027, so only the battery and load reduction can earn that credit.

Air permits and local zoning, not equipment, limit onsite gas. A 320 MW engine plant run around the clock would likely be a major source under federal air rules, with a 1–2 year permit review. Run for limited hours under enforceable limits, it can be permitted as a minor source in months. Recent Virginia permits also restrict planned generator operation on summer weekdays, and Henrico's zoning code allows data center generators to run only during outages and testing. A battery must therefore carry summer peak shaving and routine curtailment.

The resilient design costs more. On a common UPS and ride-through baseline, with the grid bill built from Dominion's tariff sheets, the recommended configuration models at about $137/MWh against $103/MWh for grid-only service with diesel backup in the base case, a difference of about $34/MWh, or $69 million a year, and $34–35/MWh across the three cases. Of that difference, about $28/MWh is the engine fleet, gas lateral and firm gas transportation in place of the diesel fleet and about $6/MWh is the battery. If a tariff mechanism credited the battery against generation billing demand, which none now does, the difference would fall by about $8/MWh. The difference buys outage endurance on firm gas, fuel diversity and a grid-forming battery that carries the campus through the transfer instead of relying on transfer schemes alone; a diesel-backed campus also runs islanded during an outage, so the difference is in how the island is formed and how long it can be held, not in whether it exists. The two arrangements are otherwise specified alike, but it remains a modeled estimate, not a measured price of resilience. At the Henrico reference site it does not buy earlier energization, because the county code confines the engines to outages and testing. It is not justified on energy cost alone.

Nuclear, geothermal, ground-source and thermoelectric options are not available to a Virginia campus this decade. No microreactor or advanced small modular reactor is in commercial operation in the United States; the one operating plant of the class, China's 210 MWe (gross) HTR-PM, began commercial operation in December 2023. INL's published microreactor cost estimates range from about 1.5 to more than ten times the paper's modeled delivered cost of grid power; INL's current estimate for its reference microreactor is about $26,000/kWe before fuel. Virginia has no usable geothermal resource for power. Ground-source heat rejection cannot scale to 100 MW. Thermoelectric (Peltier) cooling rejects more heat at the facility than it removes from the chip, so it cannot serve as bulk cooling.

The findings apply beyond Virginia. Across the U.S. regions and global markets examined in Sections 16 and 17, electricity supply limits development before water does, except in a few arid basins where evaporative cooling is proposed. PJM has cleared two auctions short at the price cap; NERC rates PJM, ERCOT and MISO at high risk by 2028–2029; Georgia Power's large-load pipeline (73,100 MW, within a 76,200 MW economic-development pipeline) is several times what its regulator has certified; Texas paused all state environmental permits for data center projects in September 2026 and New York did the same for pending applications by executive order in July; Ireland now requires new data centers of 10 MVA or more to provide dispatchable onsite or nearby generation or storage matching their import capacity, subject to derating; Singapore and Quebec allocate capacity by call. Ride-through has become a connection condition, in force in ERCOT since August 1, 2026 and approved in Ireland in September 2026, effective October 27, 2026. The recommended configuration carries over, subject to local confirmation of gas, permits and grid agreements, to the cool and temperate interior of the United States and to Northern Europe; it needs larger dry coolers and trim chillers in hot climates, a larger battery where onsite gas is restricted, heat-export interfaces where reuse is mandated, and a different configuration in Ireland, the Nordics, Quebec, Singapore and the Gulf. Section 18 sets out every option at every scale, from a 500 kW edge site to a gigawatt campus.

Key judgments. Each carries a probability term and, separately, the author's confidence in it, under the Sanctir analytic standard; the evidence column names the tier of each material premise, and the confidence level follows the weakest of them.

Judgment	Probability	Confidence	Evidence
Electricity supply, not water, is the binding constraint on new data center capacity in Virginia through 2030	Almost certain	High	Tier 1: PJM auction results, Dominion's September 2026 filing, JLARC Report 598
A ride-through requirement will apply to large loads connecting in PJM after 2027 (very likely); its terms will be close to PJM's October 2026 proposal (likely)	Very likely; likely	Moderate	Tier 1: PJM proposal of October 6, 2026; NERC Project 2026-02; FERC order in RD26-7-000; not yet filed or adopted
At the Henrico reference site the engines may not serve the campus ahead of utility service or for routine curtailment under the current code	Almost certain	High	Tier 1: Henrico Code § 24-4328(B)(2)
A dual-fuel engine fleet limited to outages and emergencies can be permitted in Virginia as a synthetic minor source, with a review measured in months rather than the 1–2 years of a major-source permit	Likely	Low	Tier 3: consultant guidance on DEQ practice and the record of Virginia data center generator fleets permitted as synthetic minors; no DEQ determination for a gas-engine fleet of this size was opened, and no source-specific emissions inventory exists

Judgment	Probability	Confidence	Evidence
Direct-to-chip liquid cooling with closed-loop dry heat rejection keeps onsite water consumption near zero in Richmond's climate, with trim needed for about 1,100 hours a year at W32 and under 100 at W40	Very likely	Moderate	Tier 1 climate data (2025 ASHRAE design conditions and TMYx typical-year hours, both reproducible from the published files); engineering estimate for the dry-cooler approach and the equipment
The recommended configuration costs more than grid-only service with diesel backup; the modeled difference is $34–35/MWh across three cases ($26/MWh if a tariff mechanism credited the battery against generation demand) on a common UPS and ride-through baseline	Almost certain (that it costs more)	High that it costs more; low in the size of the difference	Tariff sheets (Tier 1) for the grid bill; engineering estimates for equipment, fuel transportation and run hours (Section 12)
No microreactor or small modular reactor will supply a Virginia campus before 2030	Almost certain	High	Tier 1: NRC and DOE records; INL cost studies
The electricity-before-water finding holds in most of the U.S. regions and international markets examined	Likely	Moderate	Tier 1 for the U.S. and EU items; Tier 3 for several international items (Section 15)

Recommendation. For a 100–300 MW campus in Virginia energized before 2030: firm Dominion service under the new large-customer rate class; a grid-forming battery that carries ride-through, routine curtailment and participation in the statutory flexibility program; dual-fuel gas engines under an hours-limited permit for outages and grid emergencies; and direct-to-chip liquid cooling with closed-loop dry coolers. This is the strongest candidate examined on resilience and on compliance with the proposed ride-through rules. The paper does not claim it is cheapest or that it is the only workable design. Its advantages must be confirmed for each site through the interconnection study, the permit review and the electrical studies listed in Appendix A.

Review history. The draft was put through technical and citation review with AI assistance (Appendix B), and each accepted finding was checked by the author against the cited source. This is not peer review, and agreement between reviewers is not evidence that a claim is correct; the author is responsible for every statement. Review corrected the first draft's certainty on the cost advantage, the water conclusion and the status of the ride-through rules; found that PJM had published the 2028/29 uncapped price, that INL had revised its microreactor cost report upward, and that Henrico's June 2025 ordinance limits data center generators to outages and testing; identified Virginia's statutory exclusion of carbon-emitting generation from the flexibility program; and, in the seventh round, removed an early-energization benefit the Henrico code does not allow and corrected a set of regional and international facts. Version 1.1 (October 24, 2026) rebuilt the cost model on a common reliability baseline with the grid bill drawn from Dominion's tariff sheets, replaced approximate design temperatures with 2025 ASHRAE data for 41

stations, and applied Sanctir's analytic standard; a further review round checked those changes, and its findings and the changes are listed at the end of Appendix B.

2 Scope, method and evidence standards

This paper covers a 100–300 MW AI or hyperscale campus in Dominion's service territory within PJM, with a reference site in Henrico County near Richmond, and then applies the design and its conclusions across the United States (Section 16), in the main global markets (Section 17) and across every scale from edge to gigawatt campus with the full menu of power, resilience and cooling options (Section 18). It compares that scale with smaller and larger facilities. It covers power supply, cooling, water, grid stability, redundancy, controls, security, cost and policy.

Every figure carries one of three labels:

- **Primary.** Taken from an opened PJM, SCC, NERC, FERC, NRC, DOE/INL, LBNL, JLARC, county or company document.
- **Secondary.** Taken from trade press or an analyst summary of a primary document. Flagged in the text and listed in Section 15.
- **Engineering estimate.** Derived by the author from stated assumptions. The assumptions are shown.

Water is reported as consumption unless withdrawal is stated. Costs are 2026 U.S. dollars, unsubsidized, and exclude IT equipment unless stated. Capital is annualized at a 10% capital recovery factor, about 20 years at 8%.

Regulatory items are labeled by status: proposed, filed, approved or in force. A proposal informs design. It is not a compliance obligation until adopted. In the evidence tiers of Sanctir's analytic standard, the Primary label corresponds to Tier 1 (official or legal text and official data), the Secondary label to Tier 3 (reputable reporting) or, where the source is a peer-reviewed or authoritative analysis, Tier 2, and engineering estimates are the author's stated assumptions. Claims that rest on a single unverified source are marked Tier 4 or removed. Key judgments in Section 1 carry a probability term and a separate confidence level; the two are never merged.

The draft was reviewed with AI assistance in several rounds, including a citation audit, a review of the nationwide and global sections, and a full pre-publication fact check. This is not peer review. Their comments and the disposition of each are in Appendix B. Hyperlinks were opened on October 11 or 12, 2026; the tariff sheets and climate files added in version 1.1 were opened on October 22 to 24, 2026.

3 The grid constraint

PJM has cleared three consecutive capacity auctions at its price cap. The last two procured less than the reliability requirement. That is the clearest measure of the power constraint, and it comes from PJM's own results.

Delivery year	Clearing price ($/MW-day UCAP)	Uncapped price ($/MW-day; PJM simulation with offers unchanged)	Result against the reliability requirement	Source
2028/29	325.00 (cap)	554.72 RTO and Dominion zone; 776.69 ComEd	6,831 MW short, including FRR areas; 525 MW of new generation and uprates	PJM release, July 14, 2026; PJM 2028/29 BRA Report, Appendix
2027/28	333.44 (cap)	529.80 RTO; 542.83 Dominion zone	6,623 MW short (announcement); 6,517 MW (shortfall report)	PJM shortfall report; PJM 2027/28 BRA Report, Appendix
2026/27	329.17 (cap)	388.57 RTO	Met the requirement with no excess	PJM MIC results; PJM 2026/27 BRA Report, Appendix

A capacity shortfall does not mean outages will happen. It means PJM bought less than its one-day-in-ten-years standard calls for and will have to find more. The uncapped prices are PJM's own simulations of where each auction would have cleared without the temporary cap and floor, holding offers unchanged; they measure scarcity, not what customers paid. For 2028/29, PJM plans a Reliability Backstop Procurement under FERC review, with costs allocated according to state preferences. PJM attributed about 5,100 MW of the 5,250 MW increase in the 2027/28 peak forecast to data centers.

Contracted capacity is not load. Dominion's September 29, 2026 filing to PJM reports about 54 GW under contract: 11,997 MW under electric service agreements, 9,356 MW under construction letters of authorization, and 32,473 MW under early-stage letters (Dominion filing). Its data center billing peak in August 2026 was 4.8 GW. Billing demand is the sum of each customer's own peak; coincident demand, which the forecast uses, is the data center load at the system peak and is lower. Dominion's forecast excludes 19 GW (59%) of the early-stage letters, assumes a five-year ramp to 63% use of contracted capacity, and projects coincident data center demand of 5,075 MW in 2027, 9,880 MW in 2032 and 19,466 MW in 2047. Even that forecast is four times the 2026 peak by 2047. The contracted total is about eleven times the 2026 billing peak and about 2.8 times Dominion's own 2047 forecast.

The new rate class puts the risk on the customer. The SCC's final order in case PUR-2025-00058 (November 25, 2025) created rate class GS-5 for customers with a measured or contracted demand of 25 MW or more on a contiguous site and a measured or expected load factor of at least 75%, effective January 1, 2027; the class takes in qualifying new and existing customers, and its contract term, ramp and collateral provisions apply to customers signing agreements on or after that date. Customers pay at least 85% of contracted transmission and distribution demand and 60% of contracted generation demand. The contract term is 14 years, and a customer may include a load ramp period of up to four years with a minimum annual ramp of 20% (SCC final order, pp. 23–25, as read by both third-round reviewers; DCD; WYDaily). A customer that leaves early still owes the minimums for the rest of the term. Reserving more capacity than a project uses is a direct cost, not a free option. The ramp provision is the tool for phasing contract demand to the IT installation schedule, and it should be used. The order moves minimum-demand risk to the customer; other stranded-cost questions remain subject to SCC cost allocation. Separately, the SCC's July 31, 2026 order in Dominion's Rider T1 case (PUR-2026-00056) requires large customers to pay for direct-connect transmission facilities through a contribution in aid of

construction, with a revised line-extension policy to follow (Utility Dive, August 2026). That cost is site-specific and is not in the Section 12 model.

Residential bills are the political issue. JLARC estimated that unconstrained data center demand could raise a typical Dominion residential customer's generation and transmission costs by $14–$37 a month in real terms by 2040. In its unconstrained-demand scenario without VCEA compliance, Virginia would need about 54,100 MW of new in-state generation capacity by 2040 on top of about 36,000 MW existing, an increase of about 150% in nameplate capacity (JLARC, Table 3-1). This is the center of public opposition. It concerns power, not water.

4 Power sources compared

In the base case, no onsite generator delivers firm energy more cheaply than a Dominion connection. When capacity prices are uncapped, onsite-only engines are cheaper in the model, at the price of a major-source permit and full exposure to gas prices. Onsite generation earns its place on schedule, resilience and avoided capacity charges. LCOE ranges are unsubsidized figures from Lazard LCOE+ v19.0 (July 2026) unless labeled. Water intensities are approximate NREL operational medians (Macknick et al.).

Source	Firm?	Water consumption (gal/MWh, approx.)	Capex ($/kW)	LCOE ($/MWh)	Lead time (2026)	Status 2026	Assessment
Dominion grid (PJM)	Yes, subject to PJM adequacy	Indirect ~1,200 (LBNL national average 4.52 L/kWh)	GS-5 minimum charges	Tariff; capacity $118,600–121,700/MW-yr at the 2028/29 and 2027/28 caps	Years in constrained zones	Mature; capacity-short	Primary supply; schedule is the constraint
Reciprocating gas engines	Yes; modular N+2	Near zero (radiators)	Est. 1,500–2,500	Est. 80–130	Est. 12–24 months	Mature	Best onsite gas option at 50–300 MW
Simple-cycle aeroderivative	Yes; ~10 min start	~0–30	Equipment ~1,800 (BNP Paribas, secondary)	144–276	Multi-year OEM backlog	Supply-constrained	Peaking only
Combined cycle, air-cooled condenser	Yes	~0–5	2,400–2,600 (Lazard high case)	51–129	4–7 years; turbine slots into 2031	Slot-constrained	Gigawatt campuses after 2030
Solid-oxide fuel cells (Bloom)	Yes; modular	Near zero	Est. 2,500–3,500 incl. service (engineering estimate; disclosed contract totals do not state the capacity bought)	Est. 100–150	Months (vendor claim)	Commercial at GW scale	Where NOx permitting or speed decides
Binary or enhanced geothermal	Yes	Low with dry cooling	~7,000 (Lazard; Fervo Phase 1)	Not applicable in Virginia	2–5 years	Fervo first 33 MW in commercial operation Sept. 30, 2026 (Utah)	No Virginia resource

Source	Firm?	Water consumption (gal/MWh, approx.)	Capex ($/kW)	LCOE ($/MWh)	Lead time (2026)	Status 2026	Assessment
SMR	Yes (design)	~670 with towers; less dry	Est. 4,000–7,000 (engineering estimate; no SMR-specific primary cost cited)	~214 (Lazard, illustrative)	2030s	U.S.: permits issued, none operating; China's HTR-PM in commercial operation since Dec. 2023	Option only
Microreactor	Yes (design)	Near zero	26,000 first-of-a-kind, 7,000 mature, excl. fuel (INL/RPT-24-80433 Rev. 1, Nov. 2024); 25,000–54,000 and 12,000–25,000 (INL March 2026 review)	~470 first-of-a-kind, ~140 mature (INL Rev. 1); 330–980 and 160–450 (INL 2026 review)	2028–2030+	Zero-power test criticality only (U.S.)	Option only
Utility solar / onshore wind contract	No	~0–30	—	40–98 / 37–99	1–4 years	Mature	Energy and emissions attributes, not firmness
Diesel backup	Emergency only	Negligible	Est. 600–1,000	n/a	12–24 months	Tier 4-equivalent presumptive BACT for Virginia applications from July 1, 2026 (DEQ APG-576)	Last-resort reserve only

Gas turbine supply is constrained. GE Vernova reported 116 GW of gas turbine equipment backlog and slot reservations at Q2 2026, a combined figure that does not separate firm orders from reservations (Utility Dive; GE Vernova Q2 2026 results). Siemens Energy reported a 69 GW gas turbine backlog, with a further 26 GW of slot reservations, and lead times of three years or more (Siemens Energy Q3 FY2026 analyst presentation, August 5, 2026; Utility Dive). The two figures are not comparable. Reciprocating engines and fuel cells are not subject to that turbine backlog.

Fuel cells. Bloom and an AEP subsidiary announced a framework for up to 1 GW of solid-oxide fuel cells in November 2024 with an initial 100 MW order. AEP's January 8, 2026 Form 8-K reports a binding purchase of about $2.65 billion covering a substantial but unstated portion of the remaining 900 MW option, so no per-kW price can be derived from it. Oracle's agreement covers up to 2.8 GW, with 1.2 GW contracted at signing (Bloom, April 13, 2026). Brookfield's financing framework for Bloom deployments grew from $5 billion to $25 billion (Brookfield Q2 2026 letter); that is financing capacity, not committed spending. Fuel cells cost more per MWh than combined cycle. They emit very little NOx, use no water and avoid most combustion-source permitting. They fit where the air permit or the schedule is the binding problem.

Geothermal. Fervo's first 33 MW block at Cape Station, Utah, reached commercial operation on September 30, 2026, announced October 1, which Fervo describes as the first greenfield enhanced geothermal project to do so (Fervo release). Fervo reports more than 1 GW of binding power purchase

agreements (Fervo, October 1, 2026), including 396 MW to Google expected online from 2028 (Fervo, September 1, 2026); the dates are company targets. U.S. geothermal generation comes from seven western states, led by California with about 69% of 2025 output (EIA); new enhanced geothermal projects are concentrated in the Great Basin. Virginia's crustal heat flow is low, and no commercial geothermal power project exists in the state. A Virginia campus can buy geothermal attributes through a contract. It cannot get firm power from a Virginia geothermal plant this decade. A site-specific resource assessment would be needed to say more than that.

Nuclear. No advanced small modular reactor or microreactor is in commercial operation in the United States; China's HTR-PM, a 210 MWe (gross) high-temperature gas-cooled plant, has been in commercial operation since December 2023. DOE's Reactor Pilot Program produced five zero-power criticality tests in 2026: Antares, Valar Atomics, Deployable Energy, Aalo Atomics and Oklo's isotope test reactor. These are physics demonstrations. None is a power plant. An NRC letter to Oklo dated June 5, 2026 states that Oklo has no licensing application for Aurora-INL before the agency and intends to transition the project from DOE authorization to an NRC license (NRC). Westinghouse's eVinci reached zero-power criticality in Nevada in August 2026. X-energy's Long Mott construction permit has a final safety evaluation due November 2026 and a contested hearing pending. TerraPower's Natrium received its construction permit in March 2026. The NRC extended Kairos Hermes 1's completion date to April 30, 2029.

On cost, INL's bottom-up study of a 20 MWth reference microreactor (INL/RPT-24-80433, Revision 1, November 2024) estimates about $26,000/kWe overnight for the first unit, excluding the initial fuel load, and about $7,000/kWe at maturity, with a mature LCOE near $140/MWh; the report's tables put first-of-a-kind LCOE near $470/MWh and total capital investment near $34,000/kWe and $9,000/kWe for the two cases. Revision 0 (August 2024) had given $14,600/kWe, $6,000/kWe and $120/MWh; those figures are superseded. INL's March 2025 program review reported about $23,000/kWe and $10,000/kWe for the same design, and its March 2026 program review, using a newer cost tool across three designs, put first-of-a-kind capital at $25,000–54,000/kW and LCOE at $330–980/MWh, and mature units at $12,000–25,000/kW and $160–450/MWh. Every one of those numbers is a model result, not a quotation. On those figures a reactor's delivered cost ranges from about 1.7 times the modeled $84/MWh tariff bill (mature LCOE) to between six and twelve times (first-of-a-kind), and the reactor arrives after 2030. Reserve a pad and a 34.5 kV breaker position. Do not put a reactor in the financed supply plan.

Renewable contracts. Utility solar and onshore wind are the cheapest new energy. They do not make the site firm. In PJM they supply energy and emissions attributes. They belong in procurement, not in the reliability design.

5 Onsite gas: fuel supply and air permits

Onsite gas improves resilience only if the gas arrives during the events that take the grid down, and only if the air permit lets the engines run when they are needed. Both have to be designed in.

What Winter Storm Elliott showed. On December 24, 2022, PJM's forced outages peaked at 46,124 MW. PJM's April 13, 2023 presentation (slide 7) reported gas-fuel-related outages and derates that day of

44.6% for gas-only units on non-firm pipeline service, 26.4% for gas-only units on firm service, and 6.9% for dual-fuel units running on gas (PJM Operating Committee, April 2023). PJM's July 17, 2023 event report (Figure 44), on a different basis, found that about 45% of gas units without firm fuel commitments had outages on the peak day against 16% of units with firm commitments. The two documents use different denominators and are not one series; both point the same way. Well freeze-offs cut U.S. dry gas production about 20% from December 23 to 26, and several pipelines declared force majeure. The difference between firm and interruptible gas was the difference between a plant that ran and one that did not.

A data center that counts its engines in its availability case should have:

- firm interstate transportation, not interruptible service;
- a dedicated lateral with redundant metering and a pressure study at winter design conditions;
- dual-fuel engines with 48–72 hours of liquid fuel on site;
- winterized fuel trains and auxiliaries rated to the site's extreme-cold design temperature.

A campus with a lower resilience target can relax these. A campus that relies on the engines cannot.

Pipeline capacity. Transco's Southeast Supply Enhancement (1,597 MMcf/d; about $1.5 billion on Williams' project page) received its FERC certificate on January 29, 2026 (Docket CP25-10-000). Williams' Form 10-Q for Q2 2026 targets service as early as Q3 2027; earlier materials said Q4 2027 (OGJ). Transco says it removes constraints in its Zones 4 and 5. None of that capacity belongs to a campus until a firm transportation agreement is signed.

Air permits. Virginia DEQ's revised guidance APG-576 took effect April 9, 2026. Its presumptive BACT, equivalent to Tier 4 emissions, applies to data center diesel generator applications received on or after July 1, 2026. It addresses diesel generators; a dual-fuel gas engine fleet needs its own BACT analysis with DEQ. The quarter-mile same-owner aggregation practice, the ozone-season restriction and the review periods below are reported by permitting consultants (ALL4, May 2026; Trinity Consultants), not stated in APG-576. The pathways use the general federal thresholds. Classification is decided pollutant by pollutant across the whole source, on potential to emit and enforceable limits; a NOx calculation alone does not establish synthetic-minor status. DEQ's determination controls.

Pathway	Threshold (criteria pollutants)	Typical review after submittal (consultant estimate)	Fits
Synthetic minor NSR	Below 100 tpy by enforceable hour or fuel limits	4–6 months	Backup, emergencies and limited demand response
State major + Title V	100 tpy (Title V)	6–12 months	Larger fleets with moderate run hours

Pathway	Threshold (criteria pollutants)	Typical review after submittal (consultant estimate)	Fits
PSD + Title V	250 tpy (100 tpy for combined cycle)	1–2 years	Baseload onsite generation

Virginia has no expedited review. Recent permits for data center generators commonly bar planned, non-emergency operation from May 1 to September 30 between 7 a.m. and 5 p.m. unless a waiver applies (consultant guidance; confirm in the draft permit). That window covers most PJM summer peak hours. Engines therefore cannot be counted on for routine summer peak shaving. The battery has to do that work.

Why round-the-clock engines trigger a major-source permit (engineering estimate). The reference plant is 320 MW electrical. At 95% generator efficiency that is about 452,000 brake horsepower of engine output (429,000 bhp if electrical output is taken as shaft power). At an assumed post-SCR rate of 0.15 g NOx per bhp-hour, full-year operation would emit:

452{,}000 \times 0.15 \times 8{,}760 \,\text{g} \approx 594 \,\text{t} \approx 654 \,\text{short tons NOx per year}

That is above the 250 ton-per-year PSD threshold for this source type. Holding the plant below 100 tons a year limits all-engine operation to about 1,340 full-load hours (about 1,400 hours on the lower horsepower figure). These are conditional results from assumed inputs. DEQ decides classification after reviewing the actual engines, controls and operating plan. The design intent follows from them: permit the engines as a synthetic minor source for backup, emergency load reduction and limited dispatch, and do not plan on baseload onsite generation in Virginia. If baseload onsite power is required, the choices are fuel cells or a major-source permit with a 1–2 year review. Whatever the air permit allows, local zoning can be narrower: Henrico’s code limits data center generators to outages and testing (Section 7).

6 Cooling and thermal design

Direct-to-chip liquid cooling with a warm facility-water loop is the standard for AI racks. The facility-water supply temperature decides whether a Richmond summer needs water, chillers or neither.

Option	Practical rack density	Typical annual PUE	Onsite WUE (L/kWh)	Assessment
Air (CRAH, containment)	≤20–30 kW	1.3–1.6	0 with air-cooled chillers; ~1–2 with towers	Inadequate for GPU racks
Rear-door heat exchanger	~30–90 kW	1.2–1.4	Set by heat rejection	Residual air heat; retrofits
Direct-to-chip single-phase (cold plate + CDU)	100+ kW; ~70–85% of heat to liquid	1.1–1.25	~0 with dry coolers	Default for AI
Single-phase immersion	~50–100 kW per tank	1.05–1.15	~0	Niche: servicing and warranty limits

Option	Practical rack density	Typical annual PUE	Onsite WUE (L/kWh)	Assessment
Two-phase immersion or cold plate	Very high	1.03–1.10	~0	Avoid fluorinated fluids (PFAS rules) unless a non-PFAS fluid is qualified
Evaporative towers + chillers	Any	1.15–1.35	~1.0–2.0	Lowest energy, highest water
Dry coolers, closed circuit	Any, with warm water	1.08–1.25	0	Preferred with warm-water IT
Adiabatic hybrid	Any	1.08–1.20	~0.02–0.2	Peak-hour trim; uses water in those hours
Air-cooled trim chillers	Any	Raises summer PUE	0	Zero-water trim

PUE and WUE ranges are engineering estimates bounded by published benchmarks: Uptime's 2025 survey average PUE of 1.54 (1.48 for facilities built in the last five years), Google's 2025 fleet PUE of 1.09, and Microsoft's fleet WUE of 0.30 L/kWh, with zero-evaporation designs standard for Microsoft's new builds since August 2024 (Google; ESG News).

Two loops, two temperatures. At the W32 design point the facility-water loop (ASHRAE class W32) is supplied at 32°C and returns at about 42°C, and the CDU delivers chip-side coolant at about 35°C, returning at about 45°C. At W40 the facility supply rises to 40°C and the chip-side supply rises with it, to about 43°C, so W40 operation depends on the IT vendor approving that coolant temperature. The two loops never mix.

Richmond's summer sets the trim. Richmond International Airport's annual 0.4% cooling design dry-bulb temperature is 35.0°C (mean coincident wet-bulb 24.2°C; 1% value 33.6°C; 2% value 32.3°C), from the 2025 ASHRAE Handbook—Fundamentals climatic design conditions distributed in the design-day file of the TMYx 2011–2025 weather set for WMO station 724010 (climate.onebuilding.org, retrieved October 22, 2026). A dry cooler needs roughly a 4–6 K approach between the outside air and the fluid leaving it. The hourly TMYx file for the same station gives the following:

- At W32, dry coolers alone cover outside temperatures up to about 27°C. The typical year has 1,127 hours above 27°C, about 13% of the year, with an average shortfall of about 3 K in those hours (about 3,400 kelvin-hours above 27°C); adiabatic spray or trim chillers make up that difference.
- At W40, dry coolers alone cover outside temperatures up to about 34–36°C, depending on the approach actually achieved. The typical year has 66 hours above 34°C, 12 above 36°C and none above 38°C (maximum 37.8°C), so a W40 design still needs trim capacity for the hottest hours; the hours are few, but the installed trim capacity is set by the peak heat-rejection load and the approach shortfall at the design ambient, not by the hour count.

A typical meteorological year understates extreme years. Before equipment is selected, the site model should also be run against the hottest recent year of record for the station, and the trim capacity sized to it.

ASHRAE reports that most current cold plates run on W32 water with case temperatures of 80–90°C and warns that future higher-power parts may require W32 or colder (ASHRAE white paper). Design for W32 at peak, with coil area and controls able to run at W40 when the IT vendor allows it. That capability is worth about 0.02–0.04 of summer PUE (estimate) and removes most trim-chiller hours.

The air-cooled fraction limits PUE. Cold plates leave 15–30% of rack heat in air: memory, storage, power supplies, networking. That heat needs rear-door heat exchangers or fan walls on a colder loop (about 20–24°C) served by air-cooled chillers with economizers. A realistic annual PUE for the reference campus is 1.12–1.20. The low end requires W40-rated IT and a residual air fraction near 15%. Do not put a PUE in a contract until an hourly site model and manufacturer selections exist.

Thermoelectric (Peltier) cooling increases the heat to be rejected. Practical modules reach a coefficient of performance of about 0.5–1.0 at useful temperature lifts. Chillers reach about 4–8. Dry coolers on warm loops reach 15–50. Moving one watt of chip heat with a Peltier device costs one to two watts of electricity, so the facility rejects two to three watts. It is useful for spot control of optics and sensors, not for a data hall.

Warm-water tolerance is the useful principle. Logic junction limits are typically 85–105°C. Leakage power rises steeply with temperature and wear-out accelerates. The optimum is the warmest coolant that keeps the junction inside the vendor's reliability limit at full power, which with current cold plates is W32–W45.

Ground-source heat rejection does not scale. Vertical boreholes reject roughly 30–80 W per meter in continuous duty. At 50 W/m, 200 MW needs about 4,000 km of borehole, roughly 27,000 bores of 150 m each. A data center has no heating season to pull that heat back out, so the ground warms year after year. It suits sub-megawatt edge sites or seasonal storage tied to a heat customer. A site-specific thermal model would confirm the scale. It would not change the conclusion.

Heat reuse. A 40–45°C return is low-grade heat. It needs a nearby customer and usually a heat pump. The Richmond region has no large district-heating network. Provide a capped connection; count no revenue.

7 Water

Statewide, data center water use is small. At one site, it depends on the cooling design and on the local utility's peak-day margin. Dry cooling removes nearly all of the site demand. Whether water limits a project is a question about the site, not about Virginia.

Definitions. Withdrawal is water taken from a source; part of it is returned. Consumption is water evaporated or not returned. Direct water is used on site. Indirect water is consumed by the power plants supplying the site.

National. LBNL's 2024 United States Data Center Energy Usage Report estimates 66 billion liters of direct consumption in 2023, about 17.4 billion gallons or 48 million gallons a day, up from 21.2 billion liters in

2014. It estimates nearly 800 billion liters of indirect consumption using a national average generation intensity of 4.52 L/kWh. Indirect water is about twelve times direct water. The national factor is not Dominion's; a Virginia filing should recompute it from Dominion's fleet.

Virginia. JLARC found data center water use "currently sustainable," under 0.5% of state withdrawals, and about equal to a large office building for most facilities. It reported about 2.1 billion gallons of industry use in 2023, with just over a third from reclaimed water (JLARC). A University of Illinois analysis of the JLARC data puts the increase since 2019 at 86%.

Richmond area.

- Henrico planning staff, citing the county utility, report data center use of about 0.5–1 million gallons a day out of 30–40 MGD county-wide. White Oak Technology Park is advertised with 10 MGD of water and 13 MGD of sewer capacity park-wide (park marketing material). That is marketing material, not a capacity letter; the firm allocation available to any parcel must be confirmed in writing by Henrico DPU.
- Richmond's plant is permitted for 132 MGD. VDH's April 2025 sanitary survey records average production of 67.6 MGD for October–December 2024; the root-cause report gives typical production of 50–75 MGD and summer maximum days near 100 MGD. The January 2025 outage was caused by unmaintained backup batteries and generator configuration errors, not by demand (VDH).
- Wholesale contracts to the counties already run near their caps on peak days. The exposure is peak-day delivery, not annual volume.

Site arithmetic (engineering estimate). A 300 MW IT campus on fully evaporative cooling at 1.8 L/kWh consumes:

$$300 \,\text{MW} \times 24 \,\text{h} \times 1{,}000 \,\text{kWh/MWh} \times 1.8 \,\text{L/kWh} \div 3.785 \,\text{L/gal} \approx 3.4 \,\text{MGD}$$

That is an average daily rate under continuous operation, about a third of White Oak's advertised park-wide capacity, and the draw on the hottest days is higher than the average. The same campus on closed-loop dry cooling consumes fill and make-up only. The hybrid variant with adiabatic spray consumes water in peak hours; the zero-water variant with trim chillers does not. They are different designs and should be named as such in any filing.

The energy trade. If dry cooling raises annual PUE by 0.03–0.08, indirect consumption at power plants rises by about 0.14–0.36 L/kWh on a 4.5 L/kWh grid. That offsets part of the 0.3–1.8 L/kWh direct saving. Dry cooling always reduces local municipal demand, and local demand is what the water utility and the zoning board regulate.

Local zoning has tightened. On June 10, 2025, Henrico's Board of Supervisors adopted Ordinance 143-25 and Resolution 142-25 (Board minutes). The ordinance makes a data center a provisional use requiring a permit after a public hearing, and the Board rejected a companion ordinance that would have kept by-right approval in a White Oak overlay district. Section 24-4328(B) of the county code now requires equipment to be enclosed or screened, requires water cooling to use a closed-loop or recycled system

unless a provisional-use permit approves another design, and limits data center generators to operation during emergency power outages and for testing and maintenance, with testing confined to weekdays between 10 a.m. and 4 p.m. The 500-foot separation from residential lot lines is a comprehensive-plan guideline adopted by the resolution, not an ordinance setback (Richmond BizSense reported the action; the minutes carry the text). For the engine fleet in this paper, the generator provision is the controlling constraint at a Henrico site: routine economic dispatch and non-emergency demand response are not permitted uses unless the permit conditions or a code amendment allow them (Section 8). In a discretionary hearing, a documented near-zero water design, a noise model and battery-based backup answer the three objections raised most often.

8 Grid stability, ride-through and load flexibility

A campus designed in 2026 should be built to stay connected through grid faults and to cut its grid draw on request. The first is a proposed PJM requirement. The second is becoming a tariff program. Neither is in force today. Both will shape what Dominion and PJM allow to connect.

What went wrong in July 2026. At 07:56 on July 22, 2026, a phase-to-phase fault on a 230 kV line near Dominion's Roundtable substation caused about 3,800 MW of customer-initiated load transfer to backup supply; Dominion's preliminary net figure is 3,869 MW, and its separately stated initial and secondary losses of 2,970 MW and 1,099 MW are not reconciled to that net in the presentation (PJM Operating Committee, August 6, 2026; NERC Reliability Insights, Sept. 2026). Press reports put it near 3 GW. One data center back-fed the fault through three reclose attempts. PJM lists earlier events on July 10, 2024 and February 17, 2025; NERC puts the July 2024 loss at about 1,500 MW. Every load on the affected circuits saw the same voltage dip. UPS and transfer controls with tight thresholds all moved to backup at once, and the grid lost that load in an instant. FERC has directed NERC to file computational-load standards by December 31, 2026 (FERC order of July 16, 2026, Docket RD26-7-000; NERC Project 2026-02, Computational Loads).

PJM's proposal (Planning Committee, October 6, 2026). It would apply to computational loads of 50 MW or more with at least 25 MW served through power electronics. The values below are transcribed from PJM's October 6 presentation. The proposal may change before filing.

Voltage at the point of interconnection (per unit)	Must stay connected for
Above 1.20	May trip
1.10–1.20	1.0 s
0.90–1.10	Continuously
0.80–0.90	2.0 s
0.50–0.80	0.5 s

Voltage at the point of interconnection (per unit)	Must stay connected for
Below 0.50	0.25 s (cooling loads may trip below 0.35 pu)

- Frequency: continuously from 58.8 to 61.2 Hz; 299 seconds from 57.0 to 58.8 Hz and from 61.2 to 61.8 Hz, cumulative over a 10-minute window.
- Recovery: after voltage returns to 0.90–1.10 pu, consumption must return to at least 90% of the pre-disturbance level within 2 seconds, with study-supported deviations allowed where bulk-system reliability requires them. Overcurrent is limited to 150% for 0.5 seconds.
- Timing: projects entering PJM studies on or after January 16, 2027 would be covered from the start. Earlier projects would have until the later of January 16, 2028 or one year after commercial operation. PJM could require compliance in less than 90 days for facilities that pose a reliability risk. Shifting load to onsite generation would not count as compliance without written approval from PJM and the transmission owner.

PJM's document does not set a rate-of-change-of-frequency limit. NERC's draft standard includes one.

What the design has to do. A battery does not make a campus compliant. The whole chain has to behave: UPS rectifiers, static transfer switches, cooling drives, the battery inverter and the protection settings. Four steps:

1. Set UPS and transfer thresholds to the PJM voltage table rather than vendor defaults, coordinated with Dominion's fault-clearing times.
2. Return to 90% within 2 seconds without a campus-wide inrush. Stagger CDU pump and fan restarts.
3. Install a grid-forming battery at the 34.5 kV bus to hold voltage during faults and damp the power swings of synchronized GPU training jobs.
4. Prove it with electromagnetic-transient simulation before energization and after each IT generation change, then verify it at commissioning.

Load flexibility is becoming a program. Virginia HB 284 and SB 371 (2026 Acts of Assembly, chapters 377 and 378), codified at Va. Code § 56-596.7, took effect July 1, 2026. The statute defines a high energy demand customer as one with contracted or measured demand of 25 MW or more and an average annual load factor of 75% or more; requires each Phase I and Phase II utility to petition the SCC for a voluntary demand flexibility program by January 15, 2027; requires a final SCC order by November 30, 2027; and provides that carbon-emitting generating resources are ineligible to participate in the program (§ 56-596.7(B)(2)(iii)). Dominion's Large Load Demand Flexibility program is being developed on that schedule (Dominion). Separately, the SCC and the Data Center Coalition formed a multistate working group with three targets: model interruptible tariffs and an emergency load-reduction mechanism by February 1, 2027, and allocation of PJM backstop procurement costs to the large loads that drive them by January 1, 2028 (SCC–DCC letter). The emergency mechanism would let utilities curtail large loads or

require backup generation after PJM has used all other resources and before cutting residential customers.

A campus with a grid-forming battery and permitted engines can cut grid draw without cutting IT load. Three limits apply. Under § 56-596.7 the engines cannot take part in the statutory flexibility program; the battery and load reduction can. Under the summer operating restriction in Section 5, routine summer curtailment should come from the battery, with the engines held for PJM emergencies. At a Henrico site, Section 24-4328(B)(2) of the county code allows generator operation only during emergency power outages and for testing, so economic dispatch and routine demand response by the engines are not authorized uses; whether a PJM or utility emergency load-reduction call counts as an emergency under the code is a question to settle with the county in the provisional-use permit before any of that value is counted. The engines' grid value is therefore limited to outage backup and to whatever the emergency mechanism the SCC–DCC working group is drafting allows. Islanding requires a microgrid controller (IEEE 2030.7/2030.8), synchronization and reconnection logic coordinated with Dominion's protection, and black-start capability from the battery or from an engine with its own DC starting system.

9 Redundancy and reliability

Shared failures and human error decide real availability, not the number of parallel modules. Money spent on compartments, testing and procedures returns more than money spent moving an AI hall from block redundancy to 2N. Uptime's 2026 outage analysis identifies power as the leading cause of impactful outages; its summary reports that 57% of respondents to its 2025 survey said their last major outage cost more than $100,000 and one in five said it exceeded $1 million (Uptime announcement).

Ratings. Uptime Tiers I–IV mean basic capacity, redundant components, concurrently maintainable and fault tolerant. Uptime certifies design, built facility and operations separately. ANSI/TIA-942 uses Rated-1 to Rated-4 with similar meaning. The availability percentages often quoted per tier are not tier criteria and do not belong in a contract.

Topology	Description	Component overhead	Concurrently maintainable / fault tolerant	Typical use
N	No redundancy	0%	No / No	Edge, test
N+1	One spare module	10–33%	Partly / No	Mechanical plants, Tier II
Block redundant (catcher)	N active blocks plus reserve blocks via static transfer	~17–25%	Yes / Mostly	Hyperscale and AI halls
Distributed redundant (e.g., 4N/3)	Spare capacity spread across UPS systems; dual-corded loads	~33%	Yes / Mostly	Hyperscale, colocation
2N	Two independent A/B systems	100%	Yes / Yes if compartmented	Financial, government
2(N+1)	Two systems, each N+1	>100%	Yes / Yes with margin	Single-site critical government

The arithmetic, and its limit. For one path, availability A = MTBF / (MTBF + MTTR). For two independent paths, availability is $1 - (1 - A_1)(1 - A_2)$. Two paths at 99.9% give 99.9999% on paper. Real systems share things: controls, gas supply, a 34.5 kV bus, firmware, procedures. One simple way to show the effect is a common-cause term:

$$A_{sys} = 1 - (1 - A_1)(1 - A_2) - \beta (1 - A_1)$$

With β = 0.1, the same two paths give about 99.99%. The shared-failure term, not the second path, decides the result. This is an illustration, not a reliability model. A campus of this size needs a fault-tree analysis of its actual architecture. The shared elements in the reference design are the facility-water loop, the 34.5 kV tie, the gas lateral and the EPMS. Each is compartmented in Appendix A.

Recommendation. AI training halls: block-redundant electrical and N+1 mechanical. Training jobs checkpoint, and inference spreads across sites, so 2N electrical does not pay for itself. Single-site government, financial or classified workloads: 2N or 2(N+1) in a compartmented enclave.

UPS and autonomy.

- Static double-conversion UPS with lithium-ion batteries (10–15 year life against 4–6 for VRLA), installed to NFPA 855, listed to UL 9540, with UL 9540A thermal-runaway test data for the installed configuration.
- About 5 minutes of UPS autonomy. The 20 MW engines start, synchronize and take load over minutes, not seconds. During that interval the UPS carries the critical IT and CDU load and the 120 MW battery carries part of the mechanical load; because the battery is rated at half the 240 MW peak, the transfer sequence must shed or defer non-critical mechanical load until the engines accept it. Any code-required emergency system that must have power within 10 seconds (NFPA 110 Type 10) is served by the battery or by dedicated units sized for it. Starting and loading times come from manufacturer data and set the UPS and battery sizing. Fuel: firm gas transportation plus 48–72 hours of onsite liquid fuel for dual-fuel operation, with tank volume calculated from engine heat rate and expected duty cycle.
- CDU pumps on UPS. A GPU at full power reaches its thermal limit within seconds of losing coolant flow.

10 Power system controls and OT cybersecurity

The power and cooling control systems are now part of the grid's stability problem and a target for state-sponsored intrusion. Build them to a NERC CIP-equivalent baseline now, even where CIP does not apply. CISA advisory AA24-038A described PRC state actors (Volt Typhoon) positioned inside U.S. critical-infrastructure networks. That is the threat model for the EPMS, the BMS and the microgrid controller.

System	Function	Typical protocols
Protective relaying	Fault detection, isolation, transfer schemes	IEC 61850 GOOSE, hardwired trips

System	Function	Typical protocols
EPMS	Metering, power quality, event capture, ride-through verification	IEC 61850, Modbus/TCP, DNP3
Paralleling switchgear and engine controls	Synchronization, load sharing, load shedding	Vendor PLC
ATS / STS	Source transfer (ATS in seconds; STS in about a quarter cycle)	Hardwired, Modbus
Microgrid controller	Dispatch, islanding, reconnection, black start	IEC 61850, DNP3, IEEE 2030.7/2030.8
BMS	CDUs, dry coolers, chillers, leak detection	BACnet/IP, Modbus
DCIM	Capacity, assets, rack power and thermal	SNMP, Redfish, APIs
Utility interface	Telemetry, curtailment signals	DNP3 via the utility

Who the rules apply to. NERC CIP applies to registered entities' bulk-system cyber assets. A data center is generally not registered today; there is no registration category for a data center as a load. That may change for large onsite generation tied to the bulk system and for the computational-load entity NERC is defining under Project 2026-02 and FERC's July 16, 2026 order, which also directs revised registration criteria by December 31, 2026. Segmentation costs less to build than to retrofit.

Architecture (diagram in Appendix A).

- Purdue-model segmentation with ISA/IEC 62443 zones and conduits: target SL-2 for mechanical controls and SL-3 for electrical, generation and microgrid controls.
- An OT DMZ with no direct routing from enterprise IT to control networks, and one-way gateways for outbound telemetry from protection and control zones.
- Vendor remote access only through a brokered, recorded, MFA-protected session in the DMZ. No standing vendor connections.
- Passive monitoring of IEC 61850, DNP3 and BACnet traffic into an OT-aware SIEM.
- Application allow-listing on HMIs and engineering workstations. Signed firmware and software bills of materials required in procurement. Offline golden configurations for relays, PLCs and the microgrid controller.
- Ride-through and protection settings under change control. A settings change can reproduce the July 2026 event.

Safety rule. Protective relays and engine safety shutdowns must work if every networked system is compromised: hardwired trips and local manual operation, with no dependence on DCIM, BMS or the microgrid controller.

What remains. Firmware supply chain and vendor access are the largest residual risks. SBOM review, firmware signing and brokered access reduce them. They do not remove them. List them as accepted risks in the facility security plan. Frameworks: NIST SP 800-82 Rev. 3, ISA/IEC 62443-3-3 and 62443-4-2, and NIST SP 800-207 for zero trust in the management planes. These are voluntary baselines unless a tenant contract or a future NERC registration makes them binding.

11 Physical security and tenant compliance

Protection is layered from the property line inward. The utility yard, with the substation, engines, battery and gas metering, is the most consequential single target on the site.

Zone	Controls
0 — Approach	Site selection, setback, clear sightlines, no operator signage
1 — Perimeter	≥2.4 m anti-climb fence; crash-rated barriers and gates to ASTM F2656 (e.g., M50/P1: 6,800 kg test vehicle at 50 mph, penetration ≤1 m); perimeter intrusion detection; thermal CCTV; lighting
2 — Site interior	Standoff to buildings (UFC 4-010-01 as the DoD reference); vehicle inspection outside Zone 2; separately fenced utility yard with its own access control
3 — Building shell	Hardened envelope, single staffed entry, isolated loading dock
4 — Data hall	Anti-tailgating mantrap, badge plus biometric, video on every entry
5 — Cage, suite or SCIF	Tenant-controlled access; ICD 705 for classified tenants

- **Insider threat.** A 24/7 security operations center, a two-person rule for critical switching and media destruction, continuous vetting where the tenant requires it, and correlation of badge, video and IT logs.
- **Supply chain.** Software and hardware bills of materials for IT and OT; Section 889 and FCC Covered List checks for federal tenants; large transformers and switchgear treated as long-lead, single-source items with a spares plan.
- **Drones.** Private operators may detect unmanned aircraft. They may not jam, spoof or seize them. Mitigation authority under 6 U.S.C. § 124n rests with designated federal agencies and, since the December 2025 amendment, with trained and certified state, local, tribal and territorial law

enforcement; it was not extended to private critical-infrastructure owners. The controls are detection, response procedures, screened air intakes and roofs, and coordination with law enforcement.

- **EMP and geomagnetic disturbance.** MIL-STD-188-125-1 hardening is justified only for defense or continuity-of-government missions. Geomagnetic exposure arrives mainly through the utility (NERC TPL-007). On site, monitor transformer neutral current and test islanding against a degraded grid. EO 13865 sets federal EMP policy.

Government tenants. ISO/IEC 27001:2022 certification and a SOC 2 Type II report are the baselines. FedRAMP Moderate or High, and the separate DoD Cloud Computing SRG impact levels: IL4/IL5 for CUI and mission data; IL6 for classified up to SECRET, which requires cleared facilities and staff. Contractor systems holding CUI fall under NIST SP 800-171 and CMMC Level 2 (32 CFR Part 170), which assesses against Revision 2 of SP 800-171 until DoD adopts Revision 3. The colocation provider's physical protection (3.10.x) and media protection controls are inherited by the tenant and must be documented in a shared-responsibility matrix the tenant's assessor can test.

12 Cost structure and delivered-cost sensitivity

Facility construction averages $17.6 million per MW of IT, excluding the IT equipment itself. Energy is 75–85% of a hyperscale campus's non-IT operating cost. The recommended power configuration models about $34/MWh above grid-only service with diesel backup in the base case on a common UPS and ride-through baseline, or $26/MWh if a tariff mechanism credited the battery against generation demand. Cushman & Wakefield's 2026 guide reports the $17.6 million average and a 21% rise since late 2024; the $8.9–23.3 million/MW range is from a secondary summary of the guide. The per-scale values below are engineering estimates calibrated to that range.

Scale	Facility capex ($M/MW IT)	Design PUE	Energy share of non-IT opex	Typical redundancy	Onsite generation
Edge (<1 MW)	15–30	1.4–1.7	50–60%	N+1	Generator, Li-ion UPS
Small enterprise (1–5 MW)	13–22	1.35–1.6	55–65%	N+1 to 2N	Diesel
Colocation (10–50 MW)	11–17	1.25–1.45	65–75%	Distributed redundant or 2N	Diesel; increasingly gas
Hyperscale / AI (100–300 MW)	10–18	1.12–1.25	75–85%	Block redundant, N+1 mechanical	Engines or SOFC + battery
AI gigawatt campus	12–20 + onsite generation 1.5–3.0 + transmission	1.10–1.20	80–90%	Block redundant; software resilience	Dry-cooled combined cycle after 2030; engines or SOFC before

IT equipment is the largest cost at an AI campus. Secondary reporting of JLL's 2026 outlook cites AI fit-out of up to about $25 million/MW. On that figure and the $17.6 million average, the facility is about 41% of the combined cost, or about 29–42% across the $10–18 million/MW hyperscale range.

Choice	Capex delta (estimate)	Operating effect
Tier IV instead of Tier III	+15–30% facility capex	Higher maintenance; lower utilization of installed capacity
Direct-to-chip liquid instead of air	+$1–2.5M/MW	−10–20% facility energy; enables 100+ kW racks
Dry instead of evaporative heat rejection	+5–15% mechanical capex	+3–7% facility energy (PUE +0.03–0.08); −95–100% onsite water
Gas engines instead of diesel backup	+$1.0–1.7M/MW	Dispatch and curtailment value; no diesel run limits
Solid-oxide fuel cells	Est. $2.5–3.5M/MW incl. service (engineering estimate; contract totals do not disclose capacity)	Premium energy cost; very low NOx; speed
Grid-forming battery, 50% of load for 2 h	$0.4–0.8M/MW IT	Ride-through, curtailment, black start

Sensitivity. The model (version 2.1; the companion workbook publishes every input and formula) compares three supply arrangements for a 200 MW IT campus at PUE 1.15, about 2,015 GWh a year, on a common reliability baseline. All three carry the same 5-minute lithium-ion UPS on the IT and CDU load (210 MW at $450/kW plus $5/kW-yr), the same ride-through package of drive, transfer and control settings with an electromagnetic-transient study ($15 million), and 72 hours of liquid fuel for whichever backup fleet is installed ($40,000 per MW of backup). The cooling plant and its energy are also the same in all three (PUE 1.15), so the comparison prices the power-supply difference only; the capital, energy and water differences between evaporative and dry heat rejection are in the table above, not in the model, and the renewable contract in configuration C is not costed. Arrangement A adds a 264 MW diesel fleet at $800/kW plus $8/kW-yr fixed O&M and 60 test and emergency hours a year at $200/MWh. Arrangement C, the recommended configuration, adds 320 MW of dual-fuel engines at $2,000/kW plus $15/kW-yr, a $25 million gas lateral, firm gas transportation at $0.40 per dekatherm-day reserved for the fleet's full-load burn (an engineering assumption; no Transco service path has been priced), 100 outage and emergency hours a year, and a 120 MW / 240 MWh grid-forming battery at $400/kWh plus $10/kW-yr fixed O&M, 1.5% of capital a year for augmentation, and charging losses for 250 delivered cycles at 88% round-trip efficiency, priced at each case's energy rate. Arrangement E, islanded engines only, carries 360 MW of engines, an 8.5 MMBtu/MWh heat rate, $15/MWh variable O&M, firm transportation for the campus peak burn and the same battery, with its charging losses priced at engine fuel cost. Capital is annualized at 10%.

Grid bill. The bill for A and C is built from Dominion Energy Virginia's published tariff sheets at transmission delivery voltage: the Schedule GS-4 charges effective January 1, 2026 ($9.280/kW-month on-peak generation demand; $0.558/kW-month on off-peak demand above 90% of on-peak demand, which for a flat load is 10% of it; $2.310/kW-month transmission demand; 0.4648 and 0.3299 cents/kWh

on- and off-peak generation energy; 0.0157 cents/kWh distribution energy; a $343.54 monthly customer charge; and no distribution demand charge at 69 kV and above), the Rider A fuel factor of 3.7648 cents/kWh effective July 1, 2026, and the riders in force on September 1, 2026 (Rider T1 at $4.673/kW-month; Riders E, GEN, SNA, CERC, SMR, CE and OSW totaling $5.091/kW-month; Riders CCR, RPS, C1A and C4A and the deferred fuel cost charge of 0.2901 cents/kWh on all kWh, totaling 1.1096 cents/kWh). Rider T1 and the generation-side riders are billed on on-peak electricity-supply demand. Schedule GS-4 Section IX prorates the schedule's customer and demand charges by billing days over 30, so a 365-day year carries 12.17 months of those charges; the riders are billed at twelve. The modeled customer takes bundled service and claims no exemption from the non-bypassable Riders CE and RPS. Schedule GS-5's unit rates had not been filed at the status date (compliance tariffs are due about November 17, 2026), so the GS-4 transmission-voltage rates are the proxy and the GS-5 minimum-billing provisions are applied (85% of contracted transmission and distribution demand, 60% of contracted generation demand; Schedule GS-4 Section VIII applies the same minimums from January 1, 2027 to customers of 25 MW or more that do not qualify for GS-5). The result is a base-case bill of about $168 million a year, or $84/MWh (8.4 cents/kWh), 37% demand charges and 63% energy charges; EIA's 2024 average Virginia industrial price was 8.99 cents/kWh. Not in the bill: the Virginia consumption tax, the reactive demand charge, excess-facilities charges, Rider D (the tax gross-up on contributions in aid of construction), GS-5 collateral, and the direct-connect transmission contribution ordered in case PUR-2026-00056, whose implementing line-extension policy is pending before the SCC and for which no amounts have been set.

Cases. Three are run: base (gas at $4.50/MMBtu); high gas ($8.00/MMBtu, with the Rider A fuel factor 50% higher, an assumption rather than a derivation from Dominion's fuel mix); and uncapped capacity, in which the whole generation demand charge, which recovers PJM capacity cost in base rates and at $111/kW-yr is close to the 2027/28 capped price of $122/kW-yr, is scaled from the clearing price of $333.44/MW-day to the uncapped Dominion-zone simulation of $542.83. Only part of that charge is purchased-capacity expense, so the case is an upper-bound stress test, not an estimate of the bill an uncapped auction would produce. The battery earns no capacity credit in the base case, because no provision of the current tariff reduces a flat load's billing demand for a battery that discharges for two hours. A credit scenario reduces generation billing demand by 100 MW, stopped at the 60% floor (144 MW), for the case in which the demand-flexibility program due in 2027 creates such a mechanism; Schedule GS-4 Section VIII excludes PJM capacity expense from the generation charge when that floor controls, which the model cannot implement without the unpublished capacity component, so the scenario bill is an upper bound of a floor bill and the scenario is a simplified hypothetical, not a tariff outcome.

Author's model, October 2026 · 3 configurations × 3 cases, assumptions in note

The base-case outputs are $103.2/MWh for grid-only service with diesel backup, $137.4/MWh for the recommended configuration and $109.4/MWh for islanded engines; the modeled difference between the recommended configuration and grid-only service is $34.3/MWh, about $69 million a year. In the high-gas case the three are $122.0, $156.8 and $139.3/MWh and the difference is $34.8/MWh; in the uncapped-capacity case they are $111.6, $145.9 and $109.4/MWh and the difference is $34.3/MWh. The difference barely moves across cases because the grid bill is common to A and C and the engines run only 100 hours

a year; what moves is the absolute level. In the capacity-credit scenario the recommended configuration falls to $129.4/MWh in the base case and the difference to $26.3/MWh, with the 60% generation-demand floor binding before the full 100 MW reduction. The recommended configuration is never the cheapest. Islanded engines are cheapest only when capacity prices are uncapped, and then by $2/MWh; at $8 gas they cost $139/MWh, and they require a major-source permit and firm gas for the whole load. The grid-only and recommended arrangements share the UPS, ride-through package, liquid-fuel storage and cooling plant, so the difference is the cost of the engine fleet, its gas supply and the battery; the two still differ in outage endurance (72 hours of diesel against firm gas plus 72 hours of liquid fuel) and in how the island is formed (a grid-forming battery against transfer schemes alone), neither of which has been tested by a fault-tree or electromagnetic-transient study, so it is an indicative modeled cost of those capabilities, not a measured price of resilience.

Decomposition. Of the base-case difference of $34.3/MWh: engines, gas lateral and fuel storage in place of the diesel fleet, $24.0/MWh; the firm gas transportation reservation, $4.7/MWh; engine run hours less diesel test hours, −$0.7/MWh; battery capital, fixed O&M, augmentation and charging losses, $6.3/MWh. Of the $83.6/MWh grid bill: demand charges $62.1 million a year on 240 MW ($9.28/kW-month generation, $2.31 transmission, $4.67 Rider T1 and $5.09 of generation-demand riders, plus the off-peak charge and the Section IX proration) and energy charges $106.3 million at 5.28 cents/kWh, of which the Rider A fuel factor is 3.76 cents. A GS-5 bill will differ from this GS-4 proxy once the class's unit rates are filed; the Arcadia analysis of Dominion's proposed GS-5 sheet (March 2026, Tier 3) found a 150 MW load paying about $4.6 million a year less under GS-5 than under GS-4, almost entirely through demand charges, which, scaled to 240 MW, would lower the absolute levels of A and C by roughly $4/MWh and leave the difference between them unchanged.

Earlier energization can be the main financial offset, but only where onsite generation may serve the campus before or in place of utility service. At the Henrico reference site it may not: the county code allows data center generators to run only during outages and for testing, so the offset below does not apply there. Where primary onsite generation is permitted, a 200 MW AI deployment holds roughly $5 billion of IT equipment at the secondary $25 million/MW figure; at a 10% cost of capital, holding that equipment idle costs about $42 million a month, and the avoided carrying cost can exceed the annual cost difference. That depends on the delay actually avoided, the financing terms and the revenue the equipment would have earned. It is an indication, not a proof. The model workbook and script are published with the paper and should accompany any investment or regulatory use of these figures.

Equipment	Key maintenance (follow OEM and codes)
Generators	NFPA 110: monthly loaded exercise ≥30 min; 4-hour test at least once every 36 months for Level 1 systems, under the conditions of the edition in force. Gas engines: oil ~1,000–4,000 h; top-end ~30,000 h; overhaul ~60,000–80,000 h
UPS	Semiannual inspection; capacitors and fans 5–7 years; Li-ion 10–15 years

Equipment	Key maintenance (follow OEM and codes)
Switchgear and relays	NFPA 70B condition-based intervals; annual infrared; relay testing every 1–5 years; ride-through settings verified after any change
Dry coolers and adiabatic pads	Coil cleaning 1–4 times a year; fans and motors; ASHRAE 188 Legionella plan where water is sprayed
CDUs	Quarterly coolant chemistry and filters; pump redundancy and leak-detection tests
Battery system	BMS monitoring; annual capacity test; NFPA 855 fire-system inspection
SOFC	Remote monitoring; stack replacement under service agreement

13 Configuration analysis and recommendation by scale

For a 100–300 MW campus in Virginia, configuration C is the recommended design. It is not the cheapest. It is the configuration that best meets four tests at once: the proposed ride-through rules, survival of a winter gas event and a grid outage, near-zero onsite water, and a permit and construction schedule that fits inside the grid-connection timeline. Other configurations can meet some of those tests. A site-specific comparison decides. The delivered-cost column is the Section 12 model, which prices every arrangement on the same cooling plant, UPS and ride-through package; the cooling and water differences shown in the other columns are not in those figures.

Configuration	Reliability	Onsite water	Delivered cost (base case)	Schedule	Permit path (Virginia)	Verdict
A. Grid + diesel + evaporative cooling	Grid-dependent; islanded diesel backup for up to 72 hours, subject to transfer-system performance; no grid-forming battery	High	Lowest (~$103/MWh for grid + diesel on the model's common baseline)	Set by grid connection	Tier 4-equivalent diesel	Superseded for large campuses
B. Grid + battery + fuel cells + renewable contract, liquid/dry	Very high	Near zero	High	Months for fuel cells	Light	Best where NOx permitting or speed decides; 10–100 MW
C. Grid + dual-fuel gas engines (N+2) + grid-forming battery + renewable contract, liquid/dry with trim	Very high	Near zero	~$137/MWh (+ $34–35 across cases; ~$129 with a capacity credit)	12–24 months	Synthetic minor, months; at a Henrico site, zoning limits engine use to outages and testing	**Recommended for 100–300 MW, 2026–2030**
D. Grid + dry-cooled combined cycle + battery	Very high	Near zero	Lowest firm onsite $/MWh	4–7 years; turbine slots	PSD + Title V, 1–2 years	Gigawatt campuses after 2030

Configuration	Reliability	Onsite water	Delivered cost (base case)	Schedule	Permit path (Virginia)	Verdict
E. Onsite engines only (islanded)	High if gas holds	Near zero	$109–139/MWh, gas-exposed	18–30 months	PSD + Title V	Only where no grid connection is available
F. Geothermal + grid	High	Low to moderate	High capex	2–5 years	Varies	Utah and Nevada only
G. Microreactor or SMR + grid	Potentially very high	Near zero	Highest	2030s	NRC	Reserve space only

Why C.

- **Reliability across time scales.** The UPS carries the critical load for minutes. The grid-forming battery, rated at half the campus peak, carries ride-through and part of the load until the engines start. Dual-fuel engines on firm gas carry outages lasting days. The three draw on different energy sources but share buses and controls, so a fault-tree analysis must confirm the common-cause exposure.
- **Compliance.** The battery and tuned UPS controls are designed to the PJM voltage table and 2-second recovery requirement. Diesel-only designs depend on the transfer schemes that caused the July 2026 load loss. Compliance is shown by study and commissioning test, not by an equipment list. Under Va. Code § 56-596.7 only non-emitting resources can take part in the demand-flexibility program; the battery, not the engines, earns that credit.
- **Permitting.** Limiting engine hours keeps the plant a synthetic minor source with a review measured in months, not years. The battery takes over the summer peak shaving that Virginia's ozone-season restriction prevents. At a Henrico site the county code limits the engines to outages and testing, so their grid-support value depends on permit conditions the county has not yet granted to anyone.
- **Water.** Closed-loop liquid cooling and radiator-cooled engines consume almost no water. That removes water as an issue in a discretionary zoning hearing.
- **Cost.** The recommended configuration models about $34/MWh above grid-only service with diesel backup on a common UPS and ride-through baseline, $26/MWh if a tariff mechanism credited the battery; the arrangements still differ in outage endurance and in how the island is formed, so that is an indicative difference, not a measured price of resilience. Earlier energization offsets it only where onsite generation may serve the campus before utility service; at a Henrico site it may not (Section 12).

By scale (the full menu of options at each scale, and their fit by region and market, is in Section 18).

- **Edge (<1 MW):** grid, lithium-ion UPS and a generator; air or rear-door cooling. Onsite generation beyond backup does not pay.
- **Small enterprise (1–5 MW):** grid, N+1 generators, lithium-ion UPS, air-cooled chillers with economizers, liquid cooling for GPU racks. Colocation usually costs less than ownership.
- **Colocation (10–50 MW):** distributed-redundant UPS; configuration B where permits are tight; liquid-ready halls with dry coolers.

- **Hyperscale and AI (100–300 MW):** configuration C; substitute fuel cells for part of the engine fleet if NOx limits bind.
- **Gigawatt campus:** configuration C for early phases, D once turbine slots and a major-source permit are secured.

14 Policy options and their consequences

The policy problem is who pays for new large load and who carries its reliability risk; on the evidence in this paper, it is not water. The options below are grouped by the body that can act, each with the consequence the evidence in this paper supports. The paper does not recommend among them; the choice depends on how each body weighs cost allocation against speed of connection and reliability risk. The closing paragraph records positions the evidence does not support; that is the author's assessment of the evidence, not advocacy of the alternatives.

Virginia SCC

1. Retaining the GS-5 minimum-demand structure and four-year ramp, and publishing how the ramp applies to multi-phase campuses. Consequence: customers can match contract demand to the installation schedule instead of over-contracting to hold queue position, and minimum-demand risk stays with the customer.
2. Defining a capacity credit in Dominion's demand-flexibility program (petition due January 15, 2027 under Va. Code § 56-596.7) for loads that cut grid draw with storage or load reduction. Consequence: the battery acquires a compensated role that the current tariff does not give it; because the statute excludes carbon-emitting generation, engines would not qualify. Without a credit, flexibility investment at large loads stays limited to what interconnection conditions require.
3. Adopting the SCC–DCC model interruptible and emergency load-reduction tariffs and assigning PJM backstop procurement costs to the large loads that cause them, on the working group's January 1, 2028 target. Consequence: emergency curtailment becomes a defined service with known compensation, and backstop costs fall on the loads that drive them rather than on all customers.

PJM and FERC

- Filing the large-load ride-through requirements with rate-of-change-of-frequency limits aligned to NERC Project 2026-02. Consequence: one design envelope; divergent limits would force every campus to design to the more restrictive of two.
- Giving loads with verified curtailment capability faster interconnection, conditioned on telemetry and periodic testing. Consequence: queue position becomes a reward for controllability, and the verification cost falls on the customer.
- Publishing the uncapped simulation prices in the results release rather than only in the auction report appendix. Consequence: the scarcity signal reaches decision-makers who do not read the appendix.

NERC

- Registering large computational loads that operate onsite generation or batteries capable of islanding, and applying CIP-equivalent requirements to their power control systems. Consequence: a common security floor for assets that can affect the bulk system, at a compliance cost the operators would carry.

Virginia DEQ and the General Assembly

- A defined permit pathway for onsite gas and fuel-cell plants that support grid emergencies, so that ozone-season restrictions do not block operation during the PJM emergency events the new tariffs would call. Consequence: permitted fleets become usable in emergencies at the cost of a small number of summer run hours.
- Specifying in synthetic-minor permits how verified grid-support operation is accounted for against routine operation. Consequence: whether emergency hours consume the hour budget that keeps a fleet below the major-source threshold is settled in the permit rather than after an event; federal potential-to-emit rules (40 C.F.R. § 52.21(b)(4)) count all operation that enforceable conditions allow, so DEQ can allocate hours between routine and emergency operation but cannot exempt emergency emissions from the threshold.
- Deciding in statute whether permitted onsite engines may run during a PJM or utility emergency load-reduction event without affecting the customer's standing under § 56-596.7, which makes carbon-emitting resources ineligible for the flexibility program. Consequence: until that is decided, the emergency mechanism the SCC–DCC working group is drafting cannot count on onsite engines at Virginia sites.

Localities (Henrico, Chesterfield and others)

- Conditioning provisional-use permits on a cooling water budget for the summer peak day, a noise model at the property line, and a backup-power plan that names the fuel and the emissions. Consequence: hearings turn on measurable conditions rather than on the use itself.
- Stating in the ordinance or the permit whether a PJM or utility emergency load-reduction call qualifies as an outage under generator provisions such as Henrico Code § 24-4328(B)(2). Consequence: onsite fleets can support the grid when the new tariffs call on them without violating zoning; absent that statement, their grid value at such sites is zero.
- Requiring reclaimed water for any evaporative cooling where a reclaimed supply exists, and publishing metered use annually. Consequence: evaporative designs stop competing with potable supply, and the water debate rests on metered figures.
- Planning water, sewer and transmission corridors regionally before approving individual parcels. Consequence: parcel-by-parcel approvals stop committing capacity that the region has not planned.

Positions the evidence does not support (author's assessment). A statewide moratorium on water grounds: JLARC's findings do not support it. A ban on onsite gas: it would remove the most practical multi-

day outage resource available before 2030, although Virginia law already excludes it from the demand-flexibility program and Henrico's code excludes it from routine curtailment. Renewable contracts alone: they do not supply firm capacity in PJM's peak hours, so they do not answer the capacity shortfall.

15 Limitations and open items

The conclusions do not rest on any single estimate below. These figures must still be replaced with primary or site-specific data before the paper supports a filing, a contract or an investment decision.

Verification status. The author opened and read the following primary documents: PJM's results releases and auction report appendices for all three auctions; the PJM shortfall report; Dominion's September 29, 2026 forecast filing to PJM; PJM's October 6, 2026 ride-through presentation and its August 6, 2026 presentation on the July 22 event; PJM's Winter Storm Elliott report and April 2023 presentation; the SCC–DCC letter to PJM; Dominion's demand-flexibility program page; the VDH inspection and root-cause reports; the JLARC report; the Henrico Board of Supervisors minutes of June 10, 2025; the Fervo, NRC and INL documents; and the Lazard LCOE+ report. Figures from those documents are primary. The third and fourth review rounds, run on paid accounts with web access, checked the figures against primary documents and both reviewers retrieved the SCC final order; their corrections are in Appendix B.

Item	Current basis	Needed before use in a filing
Engine capex ($1,500–2,500/kW) and LCOE	Engineering estimate	OEM budget quotes for 20 MW-class dual-fuel engines with SCR
Fuel-cell price (est. $2,500–3,500/kW incl. service)	Engineering estimate; disclosed contract totals do not state capacity	Bloom Energy 10-K and 10-Q filings; customer contract disclosures
SMR capex ($4,000–7,000/kW)	Engineering estimate	A project-specific cost disclosure or DOE Liftoff figures for the named design
Aeroderivative equipment price	BNP Paribas estimate via trade press	OEM quote or a recent utility CPCN filing
AI fit-out up to ~$25M/MW	Secondary report of JLL 2026 outlook	The JLL report
Cushman & Wakefield range ($8.9–23.3M/MW)	Secondary summary; the $17.6M average and 21% rise are from the guide	The 2026 guide's tables
Market monitor attribution of 2028/29 auction cost to data centers	One secondary summary; removed from the body	Monitoring Analytics report on the 2028/29 auction
Uptime outage figures	The 57% and one-in-five figures are from Uptime's summary; the 45% power share reported in trade press is not used	Uptime Annual Outage Analysis 2026 full report
Winter Storm Elliott gas outage percentages	Two PJM documents with different denominators (Section 5)	One series from PJM's July 2023 report

Item	Current basis	Needed before use in a filing
July 22, 2026 load transfer (3,800 / 3,869 MW net; 2,970 + 1,099 MW components)	PJM and Dominion preliminary figures that do not reconcile	PJM or NERC final event report
Permit review periods (4–6, 6–12 months; 1–2 years), quarter-mile aggregation and ozone-season restriction	Consultant guidance (ALL4, Trinity)	DEQ pre-application meeting record and draft permit
NOx rate after SCR (0.15 g/bhp-hr) and 95% generator efficiency	Assumptions	Engine vendor guarantee and DEQ BACT determination for gas engines
White Oak 10 MGD water, 13 MGD sewer	Park marketing material (advertised park-wide capacity)	Henrico DPU written capacity confirmation for the parcel
Cost-model absolute levels ($103.2, $137.4, $109.4/MWh)	Author's model, version 2.1: grid bill from Schedule GS-4 transmission-voltage sheets as the GS-5 proxy; equipment costs are engineering estimates; workbook published	GS-5 unit rates when filed (compliance tariffs due about November 17, 2026); OEM quotes; a bill simulation by Dominion
Firm gas transportation ($0.40/Dth-day) and the $25 million lateral	Engineering estimates; no Transco service path or receipt point identified	Pipeline tariff rate for the contracted path and a lateral estimate from the pipeline or an EPC contractor
Transco $1.5 billion and Q3 2027 service	Williams Q2 2026 Form 10-Q and project page	Transco project disclosures at the time of contracting
Richmond design temperature and hours above 27°C and 34°C	2025 ASHRAE Handbook design conditions and the TMYx 2011–2025 typical year (Section 6)	Hourly run against the hottest recent year of record; manufacturer selections at the site design point
Dry-cooler fan power and trim hours; annual PUE	Engineering estimate	Manufacturer selections at the site design point; hourly model
Indirect water	LBNL national factor	Dominion fleet water intensity
Chesterfield water and sewer capacity	Not found	Chesterfield Utilities
Fervo 2028 start for the Google block	Company statement	Fervo project disclosures

Studies required before commitment. Interconnection study results and the earliest credible energization date; transmission contingency analysis for loss of either 230 kV line, a transformer or a bus; GPU load profile, ramp rate and harmonic study; protection coordination across utility, engines, battery and transfer systems; electromagnetic-transient study against the PJM ride-through envelope; gas deliverability and pressure study at winter design conditions; DEQ pre-application assessment; utility confirmation of peak-day water and wastewater capacity; thermal transient analysis for loss of coolant flow; battery fire-protection and thermal-runaway analysis; black-start test procedure; fault-tree reliability analysis; critical-path construction schedule with confirmed vendor lead times; and a measurement and verification protocol for curtailment.

Conflicting figures retained. The 2027/28 shortfall is 6,623 MW in PJM's announcement and 6,517 MW in its shortfall report. The July 22, 2026 load loss is about 3,800 MW (PJM; NERC), 3,869 MW net in Dominion's preliminary count, 4,069 MW as the sum of Dominion's stated initial and secondary losses, or about 3 GW (press). INL's microreactor cost figures differ between Revision 0 and Revision 1 of its 2024 report and between its 2025 and 2026 program reviews; the Revision 1 and 2026 figures are used and the earlier ones noted. PJM's two Winter Storm Elliott documents give different gas outage percentages on different bases; both are shown in Section 5.

Rules in draft. PJM's ride-through filing, NERC Project 2026-02, the SCC–DCC model tariffs, Dominion's flexibility program, the SCC's line-extension policy implementing the Rider T1 order (PUR-2026-00056), Virginia's environmental-justice permitting guidance (due December 31, 2026) and PJM's backstop procurement can each change design or cost assumptions within the life of a facility started in 2026.

Nuclear schedules are developer targets with a record of slipping; Kairos Hermes 1 moved to 2029. Lazard's SMR LCOE is explicitly illustrative.

Verification status of Sections 16–18. The nationwide and global sections rest on primary documents opened on October 11–12, 2026 for the FERC, NERC, ERCOT, PUCT, Georgia PSC, Oregon PUC, CRU, EnEfG, IMDA/EDB, EU, TenneT, Ofgem, Statnett, Danish, AEMC, Régie and company items cited, and on secondary summaries where the primary document could not be retrieved (the PUCT order of September 18, 2026, the Texas Governor's letter, the Louisiana PSC orders, the MISO LARS filing, the CRU decision on MPID 345, the Virginia Rider T1 order, the Singapore allocation details and the Saudi and Korean items). Design dry-bulb temperatures are the 2025 ASHRAE Handbook design conditions distributed with the TMYx 2011–2025 weather files (Section 16.1); international electricity prices are indicative; energization years are the author's assessment. Each is labeled where it appears.

16 Applying the design across the United States

The Virginia reference design was built against PJM's capacity shortfall, Dominion's interconnection queue, PJM's proposed ride-through rule, Virginia's air-permit practice and Henrico's zoning. Every other U.S. region has its own version of each of those five constraints. This section sets them out, region by region, and states where configuration C carries over with the same design, where it must be modified, and where a different configuration is the right answer. Status is as of October 12, 2026. Figures are primary unless labeled.

The federal layer. Four federal developments in the past year bear on every region; the first applies directly only in PJM.

- **FERC on co-location (December 18, 2025).** FERC found PJM's tariff unjust and unreasonable because it did not address service to load co-located with generation, and ordered a compliance filing within 60 days offering four service choices: network integration transmission service, interim non-firm service while upgrades are built, firm contract demand and non-firm contract demand. It also directed PJM to propose a megawatt threshold for netting load behind the meter (FERC, Docket EL25-49). The MW

threshold is PJM's proposal, not FERC's number. On June 18, 2026 FERC acted on rehearing, setting the order aside in part and requiring further PJM tariff revisions (Docket EL25-49-002).

- **FERC on large-load interconnection (June 18, 2026).** In place of the national rule DOE had asked for in October 2025 (loads above 20 MW; RM26-4), FERC issued six show-cause orders under Federal Power Act section 206, one to each RTO and ISO (Dockets EL26-67 through EL26-72), requiring each to justify its large-load interconnection practices within 60 days (FERC fact sheet). No binding national large-load interconnection rule exists today.
- **NERC.** The 2025 Long-Term Reliability Assessment (January 2026) forecasts summer peak demand rising by 224 GW over ten years, with PJM and ERCOT at elevated risk through 2028 and high risk from 2029, and MISO at elevated risk in 2027 and high risk from 2028 (NERC LTRA). The 2026 Summer Reliability Assessment (May 19, 2026) records about 58 GW of new resources added in a year (NERC SRA). On May 4, 2026 NERC issued a Level 3 Essential Action alert on computational-load modeling and ride-through, its third Level 3 alert ever, with responses due August 3, 2026. Project 2026-02 (Computational Loads) is drafting registration criteria and standards; a NERC ride-through standard does not yet exist.
- **Engines used for grid support are non-emergency engines.** The D.C. Circuit vacated the 100-hour emergency demand-response allowance for emergency engines in Delaware v. EPA, 785 F.3d 1 (D.C. Cir. 2015), and EPA conformed the regulations in 2022. A 50-hour non-emergency allowance remains at 40 CFR 60.4211(f)(3). It excludes peak shaving and financial demand-response arrangements, except under the conditions of (f)(3)(i), which allow operation dispatched by the local balancing authority or transmission operator to relieve local transmission or distribution limits; EPA's 2022 amendments removed only (f)(2)(ii) and (iii). Any engine fleet that curtails grid draw, as configuration C's does, must be permitted as a non-emergency source with the controls that implies. The Virginia analysis in Section 5 already assumes this; the point holds in every state.

Regional constraints. The table gives the binding electrical constraint in each region, the large-load rules in force, and the energization outlook for a 100–300 MW campus. Energization years are the author's assessment from the sources cited, not quotations.

Region	Adequacy and price signal (2026)	Large-load rules in force	Energization outlook	What changes for configuration C
PJM (Virginia, Ohio, Pennsylvania, northern Illinois)	Two auctions at the cap and short (6,623 MW; 6,831 MW); uncapped simulations $529.80–554.72 RTO, $776.69 ComEd	FERC co-location orders; PJM show-cause response pending; PJM ride-through proposal (Section 8); in Virginia, the SCC's July 31, 2026 Rider T1 order assigns direct-connect transmission costs to large customers	4–7 years in constrained zones	None in Ohio and Pennsylvania; Illinois carries the highest scarcity signal in PJM

Region	Adequacy and price signal (2026)	Large-load rules in force	Energization outlook	What changes for configuration C
ERCOT (Texas)	NERC: elevated through 2028, high from 2029; 2026 summer adequate	SB 6 (≥75 MW): curtailment during firm load shed, backup-generation disclosure, interconnection standards; PUCT rule 16 TAC § 25.194 adopted September 18, 2026 and effective October 8, 2026 ($100,000 study fee; security equal to the greater of $50,000/MW of contracted peak demand or allocated upgrade costs); NOGRR282 ride-through in force August 1, 2026	2–5 years, but the Governor's September 21, 2026 directive paused all TCEQ permits for data center projects pending ERCOT's review (TCEQ compliance update due October 19, 2026; ERCOT report expected December 10, 2026)	Design to NOGRR282; expect mandatory curtailment service; file the air permit only once TCEQ resumes; firm Permian gas is the cheapest in the country
MISO (Louisiana to Minnesota)	NERC: normal 2026, elevated 2027, high from 2028	ERAS, an expedited process for generation interconnection requests (up to 15 a quarter; sunset August 31, 2027); LARS (Large Load Addition Resource Study), filed at FERC October 2, 2026, a proposed 120-day study for loads above 200 MW paired with new generation; Louisiana PSC approved three Entergy combined-cycle plants (about 2.26 GW) for Meta on August 20, 2025 under a 15-year agreement, and on April 15, 2026 put seven more on an expedited schedule	3–4 years where the utility builds generation under a minimum bill; longer elsewhere	In MISO South the utility-built plant is the capacity source and the onsite engines are a resilience layer only; in MISO North the same design applies, subject to local confirmation of gas, permits and grid agreements
SPP	HILL process for high-impact large loads accepted by FERC January 2026	HILL pairs loads with electrically proximate generation	3–6 years	Study the engines as part of the HILL package
Southeast (Georgia, Carolinas, TVA, Alabama, Florida)	Georgia PSC approved about 9,885 MW of new generation by vote on December 19, 2025; Georgia Power's report of May 15, 2026 (data as of March 31) put its large-load pipeline at 73,100 MW within a 76,200 MW economic-development pipeline, with 12,400 MW committed	Georgia PSC rule of January 23, 2025 for loads above 100 MW: contract terms of up to 15 years (previously 5) and minimum bills; xAI's unpermitted "temporary" turbines in Memphis drew legal challenge before 15 permanent units were permitted (July 2, 2025); Mississippi's Permit Board approved a PSD permit for 41 turbines in Southaven on March 10, 2026	3–6 years, gated by generation build-out	The same design applies in Atlanta's climate, subject to local confirmation; the Memphis case is the argument for the paper's permitted, hours-limited, SCR-equipped approach
New York and New England	NERC: New York elevated; New England elevated under extreme heat	New York Executive Order 62 (July 14, 2026) directs DEC to hold in abeyance discretionary permit applications not yet deemed complete for data centers of 50 MW or more until a generic environmental impact statement, led by the Department of Public Service, is finished; the legislature's one-year moratorium bill (S10642) passed June 4, 2026 and is unsigned	Frozen in New York; constrained in New England by gas pipeline capacity	Not a 2026–2030 market for a new 100–300 MW campus; dual fuel with onsite liquid storage is mandatory in New England

Region	Adequacy and price signal (2026)	Large-load rules in force	Energization outlook	What changes for configuration C
Pacific Northwest (Oregon, Washington, Idaho)	NERC: elevated summer 2026, high from 2029	Oregon HB 3546 (2025) created a rate class for data processing facilities of 20 MW or more; OPUC Order 26-154 (May 7, 2026) set PGE Schedule 96 (contracts of 10 years, up to 30 years for loads of 220 MW or more; 90% minimum demand charge); PGE data center rates rose an average 29% in July 2026; PacifiCorp's update of Schedule 401 under the act is pending (UE 463); on September 8, 2026 the Governor paused state-land easements, leases and permits for data center projects through July 1, 2027	4–7 years	Budget the class uplift; dry cooling covers the design day in Portland (33.5°C) but not in Quincy (37.0°C at the Moses Lake station), which needs trim chillers
Desert Southwest (Arizona, Nevada, Utah)	NERC WECC-Basin: elevated through 2028, high after	APS large-load terms in a pending rate case (decision due by December 31, 2026); NV Energy Clean Transition Tariff approved 2025 with a 115 MW Fervo geothermal supply for Google; Nevada Executive Order 2026-005 (September 17, 2026) conditions state support for data centers on customer-funded infrastructure, water protections and grid-emergency load reduction	4–7 years	Climate, not policy, is decisive: Phoenix and Las Vegas design days exceed the W40 dry-cooler limit by 7–10 K (Section 16.1); Nevada and Utah are where new enhanced geothermal supply is being contracted this decade; existing geothermal output is largest in California
California	Elevated under extreme heat	Air districts restrict non-emergency engine operation; onsite combustion is effectively emergency-only	4–7 years	Replace the engines' curtailment role with battery duration (4 hours or more) or fuel cells

Nuclear and geothermal, where they are real. Three restarts have data center or utility offtake: Crane (Three Mile Island Unit 1, 835 MW, Microsoft), targeted for 2027 with a $1 billion DOE loan closed November 18, 2025; Palisades (about 800 MW), whose operating license was restored on July 24, 2025 and whose fuel loading began August 30, 2026 and was paused the same day after a fuel assembly tilted during handling, leaving the restart date open, with output contracted to cooperatives; and Duane Arnold (615 MW, Google), with a DOE loan of up to $1.9 billion closed September 8, 2026 and a target of the first quarter of 2029. These are single-buyer, late-decade options in PJM and MISO. New firm geothermal supply contracted to data centers this decade is in the Great Basin: Fervo's Cape Station in Utah (Section 4) and the 115 MW Fervo supply to Google under NV Energy's Clean Transition Tariff. Behind-the-meter gas at large scale exists (Stargate Abilene: about 360 MW of turbines under Texas minor-source authorizations, with a major-source PSD application for 41 more), but at that scale it requires a major-source permit and, in Texas, is subject to the 2026 permit pause.

16.1 Climate and dry cooling by site

Dry coolers alone cover the design day up to about 27°C at W32 and 34–36°C at W40 (Section 6). The annual 0.4% cooling design dry-bulb values below are the 2025 ASHRAE Handbook—Fundamentals (Chapter 14) design conditions distributed in the design-day file of each station's TMYx 2011–2025 weather set, and the hours are counted from the same station's TMYx hourly file (climate.onebuilding.org, retrieved October 22, 2026; station list in the references). Every design-day file's header names the 2025

Handbook, Chapter 14, as its data source (headers re-read October 24, 2026), and a station manifest with file names and design values and the script that reproduces the hour counts from the public files are published with the workbook. They replace the approximate values in earlier versions of this paper; the largest revisions were Salt Lake City (36 to 37.1°C), Houston (36.0 to 36.8°C) and Richmond (35.5 to 35.0°C). A typical year understates extreme years, so trim capacity should be sized to the hottest recent year at each site.

Site (station)	0.4% dry-bulb (°C)	Hours above 27°C (W32 dry-cooler limit)	Hours above 34°C (W40 limit)	W40 dry coolers alone on the design day	Design change
Columbus, Ohio (John Glenn)	32.8	631	0	Yes	None
Chicago (O'Hare)	32.9	610	17	Yes	None
Portland, Oregon	33.5	411	18	Yes on the design value	Size trim for heat-dome events (46.7°C at Portland in June 2021)
Ashburn (Washington Dulles)	34.0	896	35	Marginal	Oversize dry coolers; trim chillers for the hottest hours
Des Moines	34.0	835	21	Marginal	Oversize dry coolers; trim chillers for the hottest hours
Atlanta	34.2	1,320	7	Marginal	Oversize dry coolers; trim chillers for the hottest hours
Richmond	35.0	1,127	66	Marginal to no	Trim chillers; adiabatic trim only where water allows
Reno	36.4	1,049	201	No	Trim chillers; adiabatic trim only with water rights
Houston (Bush)	36.8	2,477	239	No	Trim chillers; humidity (coincident wet-bulb 24.8°C) limits adiabatic trim
Quincy, Washington (Moses Lake station)	37.0	895	148	No	Trim chillers
Salt Lake City	37.1	1,161	221	No	Trim chillers; chillers rather than evaporation in the Great Salt Lake basin
Boise	37.3	983	194	No	Trim chillers for 3–5 K of lift
Dallas–Fort Worth	38.9	2,367	458	No	Trim chillers for 3–5 K of lift
Las Vegas	42.9	3,111	1,233	No	Oversize dry coolers 30–50% and add air-cooled trim chillers for 7–9 K; keep W40; ride-through-rated chiller drives
Phoenix	44.0	3,839	1,753	No	Oversize dry coolers 30–50% and add air-cooled trim chillers for 8–10 K; keep W40; ride-through-rated chiller drives

Water. With closed-loop dry cooling the consumptive draw is fill, make-up and whatever adiabatic trim the site chooses. Water then limits siting only where the design would use evaporative cooling in a stressed basin: Phoenix and Tucson, the Great Salt Lake basin, Georgia's Flint basin and parts of Texas. On

September 14, 2026 the Governor directed the Texas Water Development Board to enforce data center water-use reporting. The Virginia conclusion generalizes: water is a cost and an energy penalty in most of the country, and a siting veto only for evaporative designs in arid basins.

16.2 Ride-through as a national requirement

ERCOT's NOGRR282 is the first binding large-load ride-through rule in the country and the likely template for NERC. It applies to loads of 75 MW or more where at least half the demand is served through power electronics; requires continuous operation from 58.8 to 61.2 Hz and 299 seconds in the 57.0–58.8 and 61.2–61.8 Hz bands; requires ride-through of voltage below 0.20 per unit for 0.15 seconds and of 1.10–1.20 per unit for 2.0 seconds; limits recovery overcurrent to 150%; and fully enforces the 0.50–0.80 per unit band for loads energized after January 1, 2028 (ERCOT, NOGRR282). A pending revision (NOGRR289) would give cooling loads 365 days after energization to comply, because chiller and drive vendors have not yet caught up. The design lesson is the same one Section 8 draws for PJM: the grid-forming battery, the UPS and the cooling drives must be designed to the envelope, and the chillers belong on ride-through-rated drives or on the protected bus.

16.3 Where the design transfers, changes or is replaced

- **Same configuration, subject to local confirmation:** PJM interior (Ohio, Pennsylvania), MISO North (Iowa, Minnesota, Wisconsin) and Atlanta. Design day at or below 34.5°C, firm gas available, hours-limited synthetic-minor permits routine, energization 3–7 years with capacity at the cap. The Henrico reference site carries the two limits already built into the reference design: Henrico's code confines the engines to outages and testing, and Va. Code § 56-596.7 confines flexibility credit to the battery. In every region, firm gas, the air permit, zoning, the grid-service agreement and the battery's compensation must be re-established; a climate match alone does not transfer the design.
- **Modified for climate:** Dallas, Houston, Phoenix, Las Vegas, Salt Lake City, Boise, Reno and Quincy: larger dry coolers and trim chillers; adiabatic trim only with water rights.
- **Modified for onsite-gas limits:** Texas while the TCEQ halt stands, New York under Executive Order 62, California and other nonattainment air districts: carry ride-through and curtailment on a larger battery (half of load for four hours or more), limit engines to emergency hours, or substitute fuel cells.
- **Modified for mandatory flexibility:** ERCOT (SB 6 curtailment and demand-reduction service) and any state with a flexibility tariff: size and permit the battery-plus-engine stack for repeated non-emergency dispatch. Four separate permissions are involved and none implies another: the air permit's hour limits, the federal engine rules (non-emergency classification under NSPS and NESHAP), local zoning on generator operation, and the utility's or RTO's authorization to use onsite generation for grid support.
- **Cost model:** the Section 12 model is built on Dominion's tariff components, the GS-5 minimum-billing provisions and PJM's capacity construct. It does not carry to ERCOT, MISO or any foreign tariff without re-running the workbook on that tariff's demand, energy and capacity components.

- **Replaced:** vertically integrated MISO South and the Southeast at gigawatt scale, where the fastest capacity is a utility-built combined-cycle plant under a 15-year minimum bill (the Entergy–Meta model) and onsite engines are resilience only; and the specific PJM and MISO buyers for whom a nuclear restart is contracted.

17 Applying the design in global markets

Outside the United States the same five constraints appear, but their weights change. Connection capacity is rationed outright in Ireland, Amsterdam, Singapore, Johor, Quebec and parts of Norway. Efficiency and heat reuse are mandated by statute in Germany and Denmark. Dispatchable onsite or nearby generation or storage is a connection condition in Ireland, and onsite engines are effectively excluded from flexibility roles in the European Union. Climate decides the cooling design from Dublin (0.4% design dry-bulb 22.2°C) to Abu Dhabi (45.2°C). Status is as of October 22, 2026; design temperatures and hours are from the 2025 ASHRAE Handbook design conditions and TMYx 2011–2025 hourly files described in Section 16.1.

Policy by market.

Market	Connection and policy constraint (status)	Efficiency, water and heat rules	Onsite generation	Energization outlook
Ireland (Dublin)	CRU decision CRU/2025236 (December 12, 2025), for new connections: data centers with maximum import capacity of 10 MVA or more must provide dispatchable onsite or proximate generation and/or storage matching their import capacity, subject to derating, that participates in the wholesale market; sites of 1–10 MVA must provide autoproducer capacity matching 100% of import capacity on a de-rated basis; compliant sites face no separate mandatory demand curtailment requirement; sites of 1 MVA or more must match at least 80% of annual demand with additional Irish renewables over a six-year glide path. Data centers used 23% of Ireland's metered electricity in 2025, 7,663 GWh (CSO, July 7, 2026). CRU approved EirGrid's demand fault-ride-through grid code change (MPID 345) on September 22, 2026, effective October 27, 2026	EU reporting (Delegated Regulation 2024/1364)	Mandatory and market-dispatchable, not backup	3–6 years outside Dublin; Dublin constrained
United Kingdom	Ofgem approved NESO's connections reform (CMP434/435) on April 15, 2025, reordering the queue by readiness; AI Growth Zones (Culham, North East England, North and South Wales, Scotland) are selected on access to 500 MW or more by 2030 (Culham starts at about 100 MW); NESO opened early engagement on demand fault ride-through in November 2025 (90% restoration), not yet a rule	UK ETS; manufacturing industry paid an average 17.4 p/kWh, excluding Climate Change Levy, in Q2 2026 (DESNZ, September 2026)	Planning-led; feasible	3–7 years depending on queue position
Netherlands (Amsterdam)	Amsterdam capped data center growth at 670 MVA to 2030 (67 MVA a year) and Haarlemmermeer at 550 MVA; the national decree Stb. 2023/492 (in force January 1, 2024) confines hyperscale sites (more than 10 ha and 70 MW or more) to designated areas in Hollands Kroon and Het Hogeland; TenneT reports waiting lists of at least ten years for large consumers across much of Noord-Holland and a full stop in much of Utrecht from summer 2026	Drinking-water restrictions; EU reporting	Restricted by air and planning rules	7–10 years in congested provinces

Market	Connection and policy constraint (status)	Efficiency, water and heat rules	Onsite generation	Energization outlook
Germany (Frankfurt)	Energy Efficiency Act § 11: new data centers starting operation from July 1, 2026 must reach PUE 1.2 or better within two years; energy reuse factor 10% from 2026, 15% from 2027, 20% from 2028, with statutory exceptions; existing sites PUE 1.5 by July 1, 2027 and 1.3 by 2030; 100% renewable electricity from January 1, 2027 (§ 11(5)). A cabinet amendment of June 24, 2026 (Bundestag Drucksache 21/8027, in committee as of October 2026) would allow four years to reach 1.2, relax existing-site limits to 1.6 and 1.4, move 100% renewables to 2030 and raise the threshold to 500 kW. Not law	Heat reuse favors warm return water and district-heating interfaces	Engines used routinely for flexibility are likely to exceed the MCPD 500-hour exemption	5–8 years
Nordics (Sweden, Norway, Finland, Denmark)	Norway's data center regulation (January 1, 2025) requires registration of sites above 0.5 MW; Statnett proposed in April 2026, and applied from July 1, 2026, a cut in the allowed time to commissioning for consumption connections of 100 MW or more from ten years to six. Sweden removed the data center electricity-tax reduction on July 1, 2023. Denmark's order BEK 1167 (October 2025) requires new or substantially refurbished sites above 1 MW to carry out a cost-benefit analysis and use waste heat unless that is shown not to be technically or economically feasible	Band IC industrial prices: Sweden €0.097/kWh, Finland €0.075/kWh (Eurostat, S2 2025)	Unnecessary; hydro, nuclear and wind grid	2–5 years where capacity is reserved
Spain, France	Grid-access tenders (Spain) and nuclear supply offers (France) not verified in this paper	Madrid's design day (about 37°C) needs trim; Aragón and Madrid basins are water-stressed	Feasible under MCPD	3–6 years
Singapore	Capacity is allocated by competitive call: the Green Data Centre Roadmap (May 30, 2024) promised at least 300 MW; DC-CFA2 (launched December 1, 2025) offered at least 200 MW with PUE 1.25 or better at full IT load, at least 50% of power from eligible green pathways, Green Mark Platinum and SS 715:2025; on August 21, 2026 EDB and IMDA provisionally allocated 200 MW, reported as 50 MW each to Digital Realty, Equinix, Keppel and STT GDC on Jurong Island (trade press)	Carbon tax S$45/tCO2e for 2026–2027; wholesale power about S$117/MWh in 2025 (simple average of monthly USEP) and S$332.5/MWh in August 2026, the latest month published by EMA at the status date	Restricted; LNG-fired grid	Allocation-gated
Malaysia (Johor)	Johor stopped approving Tier 1 and 2 data centers on November 27, 2025 and requires reclaimed water where water is used (51 projects approved, 17 operating); MITI's sustainability guidelines, which govern incentive eligibility, recommend a design PUE of 1.4 or better for hyperscale sites and a design WUE of 2.2 m^3/MWh or lower	Water is the stated local constraint	Feasible	2–4 years, now gated
Japan	Fifteen reactors have returned to service since 2011 (Kashiwazaki-Kariwa 6 restarted February 9, 2026 after a halted January start-up and entered commercial operation April 16, 2026); METI–MIC "Watt-Bit" council (March 2025) links grid and data center planning; OCCTO's January 2026 forecast adds about 6.6 GW of peak demand from new and expanded data centers by fiscal 2035	Tokyo is the most expensive build market (US$15.2/W)	Feasible but costly	4–7 years in Tokyo and Osaka; shorter in Hokkaido and Kyushu
South Korea	Distributed Energy Activation Act (in force June 14, 2024): grid-impact assessment for new loads of 10 MW or more in assessment areas, which a July 2026 draft rule would extend nationwide; in practice new sites of that size have become very difficult to connect in the capital region. Under the Electric Utility Act Enforcement Decree (March 2023), KEPCO may refuse supply above 5 MW that would impair grid reliability (secondary)	Fuel cells are a mature domestic option	Fuel cells favored over engines	3–6 years; capital region constrained

Market	Connection and policy constraint (status)	Efficiency, water and heat rules	Onsite generation	Energization outlook
India	State policies not verified; Mumbai is the cheapest indexed build market (US$6.64/W); Chennai (design day about 39°C) and Hyderabad (about 40.5°C) are water-stressed	Trim cooling mandatory	Feasible	2–4 years
Australia	AEMC draft rule ERC0394 (March 12, 2026) would raise the “large” inverter-based-load threshold from 5 MW to 30 MW and add a disturbance ride-through access standard for such loads; final determination due October 29, 2026. New South Wales published a Data Centre Policy Framework in August 2026	Sydney design day about 33.5°C; Melbourne about 36.5°C	Feasible	3–5 years
Gulf (UAE, Saudi Arabia)	State-led: Stargate UAE (1 GW first phase of a 5 GW campus, first 200 MW due in 2026) is to be powered by nuclear, solar and gas; Barakah’s four units have about 5,600 MW of gross capacity; Saudi Humain’s May 2025 targets of 1.9 GW by 2030 and 6.6 GW by 2034 were reported in October 2026 as about 3 GW by 2030 and 6 GW by 2034 (secondary); construction of the Humain–DataVolt site at NEOM’s Oxagon began in 2026, with a first 100 MW phase due in 2028	Design day about 45°C; all water is desalinated; Abu Dhabi industrial tariff 27 fils/kWh (36.6 fils at summer peak); Saudi tariff of 18 halalas/kWh for licensed cloud-computing operators that meet eligibility conditions; other industrial rates vary by category	Abundant state gas	2–4 years
Quebec	Connections of 5 MW or more require ministerial approval and are allocated in blocks; Hydro-Québec proposed in February 2026 a data center tariff of about 13 ¢/kWh, roughly double the large-power rate, which the Régie has not yet approved	Hydro grid; cold climate	Unnecessary	Allocation-gated
Chile, Brazil, Mexico	Chile’s environmental court ordered re-evaluation of Google’s Cerrillos permit over water (2024); Google had already redesigned to air cooling and paused the project in September 2024. Brazil and Mexico not verified	Santiago’s design day about 32.5°C: dry cooling works	Feasible	2–4 years
Kenya, South Africa	The Microsoft–G42 Olkaria geothermal campus (100 MW announced May 2024, up to 1 GW) was stalled in 2026 over capacity guarantees; South Africa’s grid makes onsite generation a necessity	Nairobi and Johannesburg design days about 29.5°C	Necessary in South Africa	Varies

17.1 Grid codes and ride-through abroad

The EU demand connection code (Regulation (EU) 2016/1388) sets frequency and voltage operating ranges for transmission-connected demand facilities but imposes no fault-ride-through duty on them, and ACER’s recommendations on amending the code add none for data centers, although the draft amended code adds ride-through requirements for some other demand categories, such as power-to-gas units. Three jurisdictions have moved ahead on their own: Ireland, where the CRU approved EirGrid’s demand fault-ride-through code change on September 22, 2026; Australia, where the AEMC’s draft rule would add a disturbance ride-through standard for inverter-based loads of 30 MW or more; and Great Britain, where NESO has begun engagement on a 90% demand-restoration requirement. ERCOT’s rule (Section 16.2) and PJM’s proposal (Section 8) complete the set. A campus designed to the ERCOT envelope is likely to meet most rules now in force or proposed, but each envelope must be checked separately.

17.2 Emissions rules for onsite engines abroad

In the European Union, gas engines and diesel generators of 1–50 MWth fall under the Medium Combustion Plant Directive (2015/2193): new natural-gas engines are limited to 95 mg/Nm³ of NOx at 15% oxygen (190 mg/Nm³ in dual-fuel gas mode), and Member States may exempt plants that run no more than 500 hours a year. Combustion plants whose aggregated rated thermal input reaches 50 MWth can fall under the Industrial Emissions Directive, depending on the aggregation rules applied. EU Stage V (2016/1628) does not apply to stationary generator sets. The consequence is the same as in the United States: a fleet used routinely for curtailment is likely to exceed the 500-hour limit (averaged over three years) and must then meet the full limits, subject to national implementing law and permit conditions, so the battery-first flexibility design is the one that travels. Data centers of 500 kW IT or more must report PUE, WUE, energy reuse factor and renewable share annually under Delegated Regulation 2024/1364.

17.3 Climate and cooling by market

Market (station)	0.4% dry-bulb (°C)	Hours above 27°C	Hours above 34°C	W40 dry coolers alone	Design change
Dublin	22.2	0	0	Yes, even at W32	None; heat export where a network exists
Oslo, Stockholm, Helsinki	26.3–27.7	7–40	0	Yes at W40; at W32, trim or added approach margin for the 7–40 hours above 27°C	None; heat export where a network exists
Amsterdam, London (Heathrow)	28.3–28.9	33–74	0	Yes	None
Johannesburg, Nairobi	29.2–29.5	208–305	0	Yes	None
Paris (Orly), Frankfurt, Querétaro, Santiago, São Paulo	31.8–32.6	212–768	2–16	Yes	Minimal trim; in Germany the PUE 1.2 limit favors W40 with near-zero chiller hours
Seoul, Singapore, Sydney, Tokyo, Johor	32.9–34.2	446–5,339	0–53	Marginal	Trim chillers; in Singapore and Johor the coincident wet-bulb (26–27°C) defeats adiabatic trim, so chillers, seawater or district cooling carry the peak
Osaka, Melbourne, Mumbai, Madrid	34.6–37.3	359–5,516	36–270	No	Trim chillers for 1–3 K; chillers rather than adiabatic trim where water is stressed
Chennai, Hyderabad	39.0–39.8	3,089–5,907	446–658	No	Trim chillers for 4–6 K; treated wastewater if any evaporation is used
Riyadh, Abu Dhabi	45.0–45.2	4,426–5,189	2,196–2,226	No	Chillers sized for the full peak; desalinated water budgeted; PUE 1.3–1.4

17.4 Configuration by market

- **Same configuration, subject to local confirmation:** United Kingdom outside London’s queue, France, northern Spain, Japan’s Hokkaido, Chile, Mexico and much of Brazil. As in the United States, firm gas,

the emissions permit, planning consent, the grid-service agreement and the battery's compensation must be established market by market before the configuration is adopted.

- **Modified for climate:** Tokyo, Osaka, Seoul, Sydney, Madrid, India and the Gulf, as in Section 17.3.
- **Modified for heat reuse:** Germany, Denmark, the Netherlands and the Nordics: raise return water to 45–50°C, add plate heat exchangers and heat-pump export skids, and site within reach of a heat network. In Frankfurt's climate the PUE 1.2 limit is within reach of direct-to-chip liquid cooling and dry coolers at W40 if trim hours stay small; whether it is met depends on an hourly thermal model and the IT equipment's water-temperature envelope, as Section 6 requires for Virginia.
- **Modified for emissions rules:** every EU market: engine run hours set by the member state's permit under the MCPD, either within the conditional 500-hour exemption or against the full emission limits; flexibility from the battery.
- **Replaced in Ireland:** dispatchable onsite or proximate generation and storage matching import capacity, subject to derating, and participating in the wholesale market. This is configuration C with the engine fleet sized to the whole import capacity and an export interconnection; it is a condition of connection, not an option.
- **Replaced in the Nordics and Quebec:** grid-only on hydro, nuclear and wind, with a battery for ride-through, heat export, and emergency generators on diesel or renewable diesel. On these grids onsite gas adds cost and little reliability that a battery and emergency generators do not already supply.
- **Replaced in Singapore:** allocation-driven; liquid cooling with district or seawater cooling and chillers, green-pathway power imports and minimal combustion.
- **Replaced in the Gulf:** state gas, solar and storage hybrids, with chillers carrying the full peak heat rejection.
- **Firm clean supply this decade:** Barakah (UAE grid), Japanese and French nuclear through the grid, Nordic and Quebec hydro, Icelandic and Kenyan geothermal (Kenya's flagship project stalled in 2026), and in the United States the Great Basin geothermal and the three nuclear restarts described in Section 16. Outside those, a new reactor or geothermal plant is not a 2026–2030 supply option for a single campus.

17.5 Construction cost by market

Turner & Townsend's 2025–2026 Data Centre Construction Cost Index (November 5, 2025) ranks Tokyo (US$15.2/W), Singapore (14.5), Zurich (14.2), Osaka (14.1), Silicon Valley (13.3), New Jersey (12.9), Oslo (12.4), Stockholm, Helsinki and Auckland (12.3), London (12.0) and Frankfurt (11.6) as the most expensive build markets; secondary summaries of the same index give Paris and Amsterdam at 10.8, Dublin and Madrid at 10.0, Atlanta 9.9, Phoenix and Columbus 9.8 and Mumbai 6.64. Turner & Townsend reports a 7–10% construction cost premium for AI data centers over traditional data centers in the United States; liquid cooling shifts cost from electrical to mechanical systems. Industrial electricity (Eurostat band IC, second half of 2025, excluding VAT) ranged from €0.075/kWh in Finland and €0.097 in Sweden

to €0.226 in Germany and €0.255 in Ireland, the highest in the EU. Band IC covers consumers of 500–2,000 MWh a year, three orders of magnitude below a 2,015 GWh campus, whose price would be negotiated and lower; the band is used here only to rank the markets. Even so, energy price, not construction cost, separates them: at the band IC levels a 2,015 GWh campus would pay about €320 million a year more for energy in Ireland than in Sweden.

18 The full menu of options by scale

Sections 4, 6 and 13 compared the options that matter for a 100–300 MW campus. This section lists every power, resilience, cooling and operating option the paper considered, at every scale from a 500 kW edge site to a multi-gigawatt campus, and states where each fits, where it does not, and why. Scale bands: edge (under 1 MW), small enterprise (1–5 MW), mid-size enterprise and colocation (5–50 MW), large colocation and small hyperscale (50–100 MW), hyperscale and AI (100–300 MW), large campus (300 MW–1 GW) and gigawatt campus (above 1 GW). The 5–10 MW, 50–100 MW and 300 MW–1 GW transitions matter because generator procurement, interconnection studies and utility tariff classes change across them: a 10 MW site buys catalog generators and connects at distribution voltage; a 75 MW site crosses ERCOT's and most large-load thresholds; a 300 MW site enters transmission-level studies and utility-built generation becomes an option. Entries are the author's engineering assessment drawing on the sources in Sections 4, 16 and 17; each option is characterized by technical capability, regulatory eligibility, commercial maturity and site economics, and lead times and costs are 2026 indications, not quotations.

18.1 Power supply options

Option	Firm?	Lead time (2026)	Scales where it fits	Where it does not fit	Assessment
Utility grid service under a large-load tariff	Yes, subject to regional adequacy	2–10 years by region (Sections 16–17)	All	Nowhere, but energization timing is the binding constraint in most regions	Primary supply everywhere; the question is when, not whether
Utility-built generation under a long minimum bill (Entergy–Meta model)	Yes	3–4 years	300 MW and above	Restructured markets without a vertically integrated utility	Often the shortest route to gigawatt capacity in MISO South and the Southeast; commits the customer to obligations of up to 15 years
Co-location at an existing power plant (behind or in front of the meter)	Yes, with FERC-defined service	2–4 years where a plant exists	100 MW and above	PJM until the co-location compliance tariff is settled; anywhere the plant's capacity is already committed	Scarce and contested; FERC's December 2025 order defines the services; expect network-upgrade cost assignment

Option	Firm?	Lead time (2026)	Scales where it fits	Where it does not fit	Assessment
Reciprocating gas engines, dual fuel, N+2	Yes	12–24 months	10–300 MW as the resilience fleet; up to 1 GW in blocks	EU and California as a flexibility resource; Ireland only if sized to import capacity; anywhere firm gas is unavailable	The paper's recommended resilience layer; hours-limited permits keep it a minor source
Simple-cycle gas turbines (aeroderivative or frame)	Yes	2–4 years; OEM slots scarce	100 MW–1 GW+	Nonattainment areas without a major-source permit; the Texas freeze	Faster to permit under standard permits in some states, but the Memphis and Abilene cases show the political cost of unpermitted or "temporary" units
Combined cycle with dry (air-cooled) condenser	Yes	4–7 years; turbine slots into 2031	500 MW–multi-GW	Anything below 300 MW; any schedule before 2030	The right gigawatt answer after 2030; PSD and Title V permit of 1–2 years
Solid-oxide fuel cells	Yes	6–18 months	5–100 MW; blocks up to 1 GW (AEP, Oracle)	Where energy cost dominates	Premium energy, near-zero NOx and water, no combustion permit; best where the air permit or the schedule binds (California, Korea, nonattainment areas)
Grid-forming battery, 50% of load for 2 hours	Firm for minutes to hours	9–18 months	All above 1 MW	Nowhere; the duration is the design variable	Ride-through, curtailment, black start; the one flexibility resource no rule examined excludes, including Virginia's statute and the EU's engine rules; compliance and compensation still have to be established case by case
Battery, 4–8 hours (lithium-ion or long-duration)	Firm for hours	12–24 months	10 MW–1 GW where onsite gas is restricted	Where firm gas and permits make engines cheaper	Replaces the engines' curtailment role in California, New York, the EU and heat-reuse markets
Diesel generators, Tier 4-equivalent	Emergency only	12–24 months	Edge to 50 MW as sole backup; 100 MW+ as last-resort reserve	As a dispatchable or curtailment resource anywhere	Run-hour limits and local zoning make diesel a reserve, not a tool
Renewable diesel (HVO) in the same engines	Emergency only	Fuel supply dependent	Where diesel is politically or regulatorily constrained (Nordics, EU cities)	Where supply is unreliable	Same engine, lower emissions profile; does not change permit class
Utility solar, wind and storage contracts	No (energy and attributes)	1–4 years	All	As the reliability design	Procurement, not resilience; firm only with storage and a capacity product
Onsite solar with storage	Partly	12–24 months	Edge to 50 MW; Gulf hybrids at any scale	Land-constrained sites	Material only where land and sun are cheap (Gulf, Desert Southwest)
Nuclear restart or existing-plant PPA	Yes	Contracted now for 2027–2029 delivery	300 MW–1 GW single buyers	Everyone else; the three U.S. restarts are already contracted	Real for named buyers in PJM and MISO; a grid-level resource elsewhere (Japan, France, UAE)

Option	Firm?	Lead time (2026)	Scales where it fits	Where it does not fit	Assessment
Small modular reactor	Yes (design)	2030s	300 MW+ campuses willing to reserve land	Any 2026–2030 supply plan	Reserve a pad and a breaker position; no U.S. unit operates
Microreactor	Yes (design)	2028–2030+	Edge and remote sites in principle	Any financed plan this decade	First-of-a-kind cost about $26,000/kWe before fuel (Section 4)
Geothermal (hydrothermal, enhanced, closed-loop)	Yes	2–5 years where the resource exists	50–500 MW in Nevada, Utah, California, Iceland, Kenya, Indonesia, the Philippines, Turkey, New Zealand	Virginia, the eastern United States, most of Europe and Asia	Firm and low-water where the resource is; the resource, not the technology, decides
Hydro-backed grid (Quebec, Nordics, Pacific Northwest)	Yes	Allocation-gated	All	Where allocation is closed	Among the lowest-cost firm clean power where it exists; the constraint is political allocation
Hydrogen-ready engines and turbines with hydrogen or ammonia storage	Yes (design)	Equipment now; fuel supply 2028 or later	100 MW and above where low-carbon multi-day backup is mandated	Everywhere today, on fuel cost and supply	Order engines hydrogen-ready; treat the fuel as a 2030s option
Long-duration storage (iron-air, flow, 10–100 hours)	Firm for 10–100 hours	2027 and later at commercial scale	100 MW and above in markets that bar onsite combustion	Land-constrained sites; cost per kW is high	Bridges the multi-day gap a 2–8 hour battery cannot; early commercial, not yet bankable for a single campus
Combined heat, power and cooling (absorption chillers on engine or turbine exhaust)	Yes	12–30 months	10–300 MW in hot climates with high onsite run hours (Gulf, Singapore)	Any site whose permit limits engine hours, which is the paper's own strategy	Turns exhaust heat into chilled water; pays only where the engines run most of the year
Aggregated flexibility (virtual power plant participation)	No	Program dependent	Multi-site operators at any scale	Markets without flexibility tariffs	Monetizes battery and load flexibility across sites; the battery is the eligible asset

18.2 Resilience and operating options

Option	Scales where it fits	Notes
UPS autonomy of 5 minutes with lithium-ion batteries	All	The floor for any site; CDU pumps must be on it
Block-redundant electrical, N+1 mechanical	50 MW and above for AI training	Checkpointing and multi-site inference make 2N electrical unnecessary for training halls
2N or 2(N+1) compartmented enclaves	Edge to 50 MW for financial, government and classified loads	Pays only where a single site must not fail

Option	Scales where it fits	Notes
Islanding with a microgrid controller and black start	10 MW and above with onsite generation or a grid-forming battery	Required to turn backup assets into grid-support assets; needs utility protection coordination
Geographic load shifting and workload checkpointing	100 MW and above, multi-site operators	Software resilience substitutes for hardware redundancy at gigawatt scale; depends on fiber and scheduler design
Participation in flexibility, interruptible and emergency tariffs	25 MW and above where tariffs exist (ERCOT, Virginia from 2027, Ireland)	Revenue and interconnection advantage; the battery is the eligible resource in Virginia and the EU
Firm gas transportation, dual-fuel engines, 48–72 hours of liquid fuel	Any site that counts its engines in its availability case	Winter Storm Elliott (Section 5) shows interruptible gas does not provide resilience
Fault-tree and electromagnetic-transient studies	50 MW and above	The accepted means of demonstrating ride-through and availability before energization
Flywheel or supercapacitor UPS	Any scale where seconds of ride-through suffice or battery fire rules bind	Seconds to tens of seconds of autonomy; no thermal-runaway hazard; pairs with fast-start generation, not with minutes-to-start engines
Thermal energy storage (chilled-water or ice tanks)	10 MW and above, especially hot climates	Keeps cooling alive through a power transfer and shifts chiller load off peak hours without drawing on the battery; sized in minutes for ride-through or hours for peak shifting
Staged energization under block-by-block service agreements	100 MW and above	Energizing 50 MW blocks as utility capacity and permits arrive often has more schedule value than a full onsite plant built ahead of utility service; the GS-5 ramp provision and Georgia's contract terms are built for it
Power capping and workload interruption	All scales with AI training loads	Capping GPU power or pausing training is a capacity-reduction resource distinct from islanding; it can meet a curtailment call without any onsite generation and is usually the lowest-cost flexibility available
High-voltage DC or 800 V distribution inside the hall	300 MW and above with megawatt-class racks	Cuts conversion losses and copper at gigawatt scale; not yet the default, and it changes UPS and protection design

18.3 Cooling options

Option	Rack density	Onsite water	Scales and climates where it fits	Where it does not fit
Air cooling with containment (CRAH)	Up to 20–30 kW	Low to moderate	Edge, enterprise, legacy colocation	AI racks above 30 kW

Option	Rack density	Onsite water	Scales and climates where it fits	Where it does not fit
Rear-door heat exchangers	30–80 kW	Low	Retrofits and mixed halls at any scale	New AI halls, where direct-to-chip is cheaper per kW
Direct-to-chip liquid cooling with warm facility water (W32/W40)	100 kW and above	Near zero with dry heat rejection	All scales above 1 MW; the paper's standard	Nowhere, but the heat-rejection choice below decides water use
Immersion cooling (single- or two-phase)	100 kW and above	Near zero	Edge, specialized high-density deployments	Mainstream AI halls where serviceability and vendor support favor direct-to-chip; two-phase fluids face PFAS restrictions in the EU
Dry coolers (closed-loop)	Any	Fill and make-up only	Design days up to about 27°C at W32 and 34–36°C at W40: the northern United States, Northern Europe, Nordics, Quebec, highland Africa	Hot-dry and hot-humid climates without trim
Adiabatic trim on dry coolers	Any	Peak hours only	Dry climates with water rights (Reno, Madrid with limits)	Humid climates (Houston, Singapore, Johor) and stressed basins (Phoenix, Utah, Chennai)
Air-cooled trim chillers	Any	None	Hot climates everywhere; the zero-water variant	Adds capital and a few percent of annual energy
Evaporative cooling towers	Any	High (about 1.8 L/kWh)	Where water is abundant and cheap and zoning permits	Arid basins, discretionary zoning hearings, Henrico (closed-loop required)
Seawater, lake or river cooling	Any	Withdrawal, little consumption	Coastal and lakeside sites with permits (Jurong Island, Nordic fjords, Great Lakes with Compact rules)	Inland sites; permitting is slow
District cooling	Any	Depends on the provider	Singapore, Gulf cities, campuses near existing networks	Greenfield sites without a network
Heat reuse into district heating via heat pumps	Any	None	Germany, Denmark, Netherlands, Nordics, any site near a heat network	Sites without a heat customer within a few kilometers
Ground-source heat rejection	Any	None	Edge and enterprise sites below about 5 MW	Anything larger: borefield area scales with load (Section 6)
Thermoelectric (Peltier) cooling	Component level	None	Spot cooling of sensors and optics	Any bulk heat rejection: it increases the heat to be rejected (Section 6)
Liquid-to-air coolant distribution units	40–150 kW	None beyond the room's air system	Edge, enterprise and colocation retrofits that want liquid-cooled racks without a facility-water loop	Halls above a few megawatts of liquid-cooled load, where a facility-water loop is cheaper
Hybrid heat rejection (dry coolers with switchable evaporative or chiller stages)	Any	Low on most days; peak hours only	Sites that must guarantee zero-water operation on demand while keeping efficiency the rest of the year	Sites where the simpler zero-water variant already covers the design day

18.4 What the menu shows

Three findings hold for a new grid-connected campus across the scales and markets examined. First, the grid is the primary supply and its timing is the binding constraint; onsite generation buys schedule and resilience, not cheaper energy, except where capacity prices are uncapped or the utility builds the plant. Second, the grid-forming battery is the one flexibility and ride-through resource that no rule examined

excludes: ERCOT's rule, PJM's proposal, Virginia's statute, Ireland's connection policy and the EU's engine limits all leave room for it. Physical capability is not the same as compliance or compensation, which have to be established under each rule, tariff and interconnection agreement; what the battery offers is that no rule examined excludes it. Its duration, not its presence, is the design variable. Third, the cooling design decides how much water matters: direct-to-chip liquid cooling with closed-loop dry heat rejection reduces onsite water to fill, make-up and domestic use in temperate climates and to a trim-hours budget in hot ones, so water rarely decides siting, though municipal service and local reporting rules still apply. The options that do not fit this decade are the ones that depend on a resource or a regulator that has not arrived: new reactors, geothermal outside known fields, and firm clean power in markets that have not allocated it.

ANNEX

Appendices

Appendix A. 200 MW reference design

The reference campus is 200 MW of critical IT in four 50 MW two-story buildings on 150–250 acres. Peak facility load is about 240 MW. The annual PUE target is 1.12–1.20 and the annual onsite WUE target is below 0.05 L/kWh. Electrical distribution is block redundant (N+1 per building). Mechanical systems are N+1. The campus is designed for Tier III concurrent maintainability, with Tier IV compartments only for an optional government enclave.

Engine fleet. Sixteen dual-fuel engines of about 20 MW each, 320 MW nameplate, arranged N+2. With two engines out, 280 MW remains. After summer derating and auxiliary loads of roughly 8%, about 258 MW is deliverable against a 240 MW peak. The first draft used 16 engines of 18 MW, which left only 12 MW of margin before derating; the second external review caught it.

Battery. About 120 MW / 240 MWh nameplate. Usable energy, minimum state of charge, inverter current limits, auxiliary draw, degradation and the reserve held for black start must all be set by study. The nameplate rating does not guarantee two hours at 120 MW under all conditions. At 120 MW the battery is rated at half the 240 MW peak; it cannot carry the whole campus, so the transfer sequence must define which mechanical loads are shed or deferred until the engines accept load, while the UPS carries the critical IT and CDU load.

Richmond variant. Site in Henrico's White Oak Technology Park (dual 230 kV supply, 500 kV nearby, 10 MGD of advertised park-wide water capacity) or an equivalent Chesterfield site, subject to a provisional-use permit. Contract under GS-5 with demand phased to IT installation. Engines permitted as a synthetic minor source with BACT set by DEQ for gas engines. Under Henrico Code § 24-4328(B)(2) the engines may run only during emergency power outages and for weekday daytime testing unless the permit conditions say otherwise; the battery therefore carries ride-through, summer peak shaving and routine curtailment, and the engines carry outages and, if the county agrees they qualify, PJM emergencies. At this site the engines cannot serve the campus ahead of utility energization. The zero-water cooling variant (trim chillers instead of adiabatic spray) keeps water out of the hearing record and meets the code's closed-loop cooling requirement.

Studies that must be complete before the design is committed. Fault levels and breaker duty with engines and battery in parallel with the grid; transformer loading under each line, bus and transformer outage; battery power and energy sizing by electromagnetic-transient study against the PJM ride-through envelope; dry-cooler and trim-chiller selections at the site's ASHRAE design point; gas lateral pressure at winter design conditions; and the remaining items listed in Section 15.

A.1 Electrical one-line

Reference design · electrical one-line, 200 MW IT campus

Two 230 kV lines from separate Dominion substations feed a ring bus and four 100 MVA transformers, one of them spare. Three in service carry the 240 MW peak at a 0.95 power factor, about 253 MVA, at 84% of their 300 MVA nameplate; with any one transformer out, the spare restores full capacity. Engines and the battery connect at 34.5 kV, so the microgrid controller can island the campus. UPS-protected IT and CDU pumps are separated from engine-backed mechanical loads.

A.2 Cooling loop

Chip heat moves from cold plates through CDUs to a closed facility-water loop and out through dry coolers; peak-hour trim uses adiabatic spray or, in the zero-water variant, air-cooled chillers. Residual air heat has its own colder loop.

Reference design · cooling loops, W32 design point

A.3 Controls and OT segmentation

Control networks follow the Purdue model with IEC 62443 zones; protection is hardwired and independent of every networked layer.

Reference design · control networks by Purdue level and IEC 62443 target level

A.4 Site layout and security zones

Security zones nest from the property line to the tenant cage; the utility yard is separately fenced inside Zone 2.

Reference design · site security zones (not to scale)

Appendix B. Disposition of external reviews

The draft was reviewed in several rounds with AI assistance. This is not peer review; each accepted comment was checked by the author against the cited source before it was applied. The first round was an adversarial review of the first draft and the second a final-stage fact check and edit of the revised draft. The third round set four tasks: verify 24 figures against primary documents, recompute six engineering numbers, list remaining errors and give a publication verdict. The fourth round put the fifteen corrected statements back, with their primary sources, for confirmation. The fifth round was a citation audit: all 43 hyperlinks were opened and checked for resolution and description, and 36 legal, regulatory, standards and document citations were sent back for verification. Every accepted comment is reflected in the text above.

First review

Comment	Disposition	Where
2028/29 shortfall of about 6,831 MW not stated	Accepted; verified in PJM’s July 14, 2026 release	Sections 1, 3
GS-5 also requires a load factor above 75%	Accepted; verified in reporting on the final order	Section 3
2026/27 uncapped price $388.57/MW-day	Accepted; verified in PJM MIC results	Section 3

Comment	Disposition	Where
“Optimal” overstates the case; costs not quantified	Accepted; sensitivity model added; recommendation reframed	Sections 12, 13
Firm gas supply risk missing	Accepted; Winter Storm Elliott data and Transco expansion added	Section 5
Air permit timelines missing	Accepted; pathways, thresholds, ozone-season restriction and NOx estimate added	Section 5
Interruptible and flexibility tariffs missing	Accepted; Dominion program and SCC–DCC working group added	Sections 8, 14
PJM ride-through values not specified	Accepted; October 6, 2026 proposal tabulated	Section 8
PUE 1.10–1.15 too low for Virginia summers	Accepted; revised to 1.12–1.20	Section 6
Local zoning treated in passing	Accepted; Henrico June 2025 action added	Sections 7, 14
Secondary cost sources	Accepted; labeled and listed with the primary source needed	Section 15
Fault levels, breaker duty and battery sizing need study	Accepted as a design-stage requirement	Appendix A
Availability math needs common-mode factors	Accepted; common-cause term added as an illustration	Section 9
Claimed correction on the 2026/27 margin	Not a correction; the reviewer’s figures agreed with the paper	—

Second review

Comment	Disposition	Where
“Power, not water” stated as universal; water can bind at a site	Accepted; conclusion restated as statewide versus site-specific	Sections 1, 7
Ride-through requirements treated as settled	Accepted; labeled as proposed throughout; a battery alone does not establish compliance	Sections 1, 8, 13
16 × 18 MW engines leave 12 MW of margin at N+2	Accepted; fleet resized to 16 × 20 MW (320 MW)	Appendix A, Sections 5, 12
Cost model omits battery O&M, augmentation and losses; capacity-charge credit undocumented	Accepted; costs added, inputs stated, credit assumption disclosed; premium revised from $18 to $23/MWh	Section 12

Comment	Disposition	Where
“Only configuration that meets” is an unsupported exclusivity claim	Accepted; reworded	Section 13
“One month of energization covers a year of premium” overstated	Accepted; restated as an indication with its conditions	Section 12
Dry-cooling energy penalty inconsistent (1–5% vs PUE +0.03–0.08)	Accepted; reconciled to 3–7%	Section 12
W40 on dry coolers alone at 35°C has no margin at a 6 K approach	Accepted; corrected to 34–36°C with trim retained	Section 6
NOx calculation is conditional, not a permit determination	Accepted; stated as conditional; DEQ determination controls	Section 5
Permit review periods and ozone-season restriction need a documented basis	Accepted; labeled as consultant guidance	Sections 5, 15
Availability formula is illustrative, not a model	Accepted; stated as such; fault-tree analysis required	Section 9
INL first-of-a-kind LCOE missing; figures should distinguish report revisions	Accepted; 2024 report and 2026 review figures both given	Section 4
Zero-water and hybrid cooling variants should be named separately	Accepted	Section 7
Richmond plant 67.6 MGD average needs a source	Accepted; VDH inspection report cited; root-cause report figures added	Section 7
White Oak water and Henrico ordinance figures need primary documents	Accepted; labeled and listed	Sections 7, 15
Design-stage study list	Accepted; added	Section 15, Appendix A
Many primary figures marked “unverified”	Not accepted as a defect; the reviewer could not retrieve documents the author opened; verification status stated	Section 15
Geothermal conclusion “too categorical without a site assessment”	Partly accepted; wording qualified; no commercial resource exists in Virginia and the conclusion stands for this decade	Section 4

Third round

Comment	Disposition	Where
PJM published the 2028/29 uncapped simulation ($554.72 RTO and Dominion; $776.69 ComEd) in its auction report appendix	Accepted; the appendix was opened; table populated and the open item removed	Sections 3, 14, 15
2027/28 uncapped prices should cite PJM's report, not Calpine	Accepted	Section 3
INL/RPT-24-80433 Revision 1 (November 2024) supersedes Revision 0: $26,000 and $7,000 per kWe, ~$140/MWh mature, ~$470/MWh first unit	Accepted; both revisions and the 2025 review deck were opened	Sections 1, 4, 15
Henrico Code § 24-4328(B)(2) limits data center generators to outages and testing, which conflicts with routine engine dispatch at the Henrico site	Accepted; Board minutes opened; engine role at the Henrico site restated	Sections 1, 5, 7, 8, 13, 14, Appendix A
500 ft separation is a comprehensive-plan guideline, not an ordinance setback	Accepted	Section 7
"No operating units" is false globally; China's HTR-PM operates	Accepted; limited to the United States	Sections 1, 4
Brookfield framework is $25 billion, not $5 billion; AEP's $2.65 billion does not buy a stated MW quantity, so no $/kW can be derived	Accepted; per-kW figure removed and relabeled an estimate	Sections 4, 12, 15
GE Vernova's 116 GW mixes backlog and reservations; Siemens' 69 GW is backlog alone plus 26 GW of reservations	Accepted	Section 4
Winter Storm Elliott percentages drawn from two PJM documents with different denominators	Accepted; both series shown and labeled	Sections 5, 15
APG-576 took effect April 9, 2026; its presumptive BACT applies to diesel applications from July 1, 2026, not to gas engines; aggregation and ozone-season items are consultant guidance	Accepted	Sections 4, 5
NOx conversion omits generator efficiency	Accepted; recomputed at 95%: 452,000 bhp, 654 short tons, about 1,340 hours	Section 5
NOx alone does not establish synthetic-minor status	Accepted	Section 5
Transco: Q3 2027 target and about $1.5 billion per Williams' 10-Q; FERC CP25-10-000, 1,597 MMcf/d	Accepted; 10-Q figures used	Section 5
67.6 MGD is an October–December 2024 average	Accepted	Section 7
Water formula omits the kWh/MWh factor; result is an average rate	Accepted	Section 7
White Oak 10 MGD is advertised park-wide capacity	Accepted	Sections 7, 15, Appendix A
Contracted-to-actual ratio is 11:1 against the billing peak and 2.8:1 against the 2047 forecast; billing and coincident demand differ	Accepted; denominators stated	Sections 1, 3

Comment	Disposition	Where
JLARC's 150% is nameplate capacity in the unconstrained scenario (54,100 MW added to 36,000 MW)	Accepted	Section 3
Capacity-charge credit is not a GS-5 entitlement; show a zero-credit case; state the diesel fixed O&M; premium reconstructs to $22.9–23.7/MWh	Accepted; zero-credit case added ($119/MWh, premium about $29/MWh); inputs and exact outputs stated	Sections 1, 12, 13
"No onsite generator is cheaper" is too absolute given the uncapped case	Accepted; limited to the base case	Section 4
Ride-through: study-supported deviations and sub-90-day acceleration omitted	Accepted	Section 8
UL 9540A is a test method; NFPA 110 Type 10 does not describe 20 MW engine loading; the 36-month test is conditional	Accepted; reworded; the battery covers the engine start interval	Sections 9, 12
Transformer capacity should state power factor and loading	Accepted; 253 MVA at 0.95 pf on 300 MVA in service	Appendix A
Fervo ~900 MW confirmed in its September 24, 2026 release (updated to more than 1 GW in round seven); the 2028 start is a company target	Accepted	Section 4
Uptime 45% is not in the public summary	Accepted as trade-reported	Sections 9, 15
GS-5 75% load factor and 14-year term confirmed from reporting, not the order PDF; Reviewer A reports the order includes them and an optional ramp	Superseded in the fourth round: both reviewers retrieved the order; its terms and the four-year ramp option are now cited	Sections 3, 15
3,800 MW July 22 figure should be attributed to PJM's August 6, 2026 presentation as well as NERC	Accepted; PJM deck opened; event detail added	Section 8
SMR capex was attributed to a microreactor review	Accepted; relabeled an engineering estimate and listed	Sections 4, 15
Dual 2027/28 shortfall figures; indirect water uses the national factor; NOx rate is an assumption	Already disclosed; retained	Sections 5, 7, 15

Verdicts. Reviewer A: sound enough for publication as a working paper, with narrow remaining issues. Reviewer B: not ready in the submitted form, because the Henrico generator restriction, the unvalidated capacity-charge credit and three source errors were substantive. All of those items are corrected in this version. The capacity-credit assumption is now shown beside a zero-credit case, and the paper remains a technical working paper, not a permitting, financing or interconnection document.

Fourth round (confirmation of corrections)

Both reviewers opened the primary documents and confirmed items 1–5 and 7–14 of the corrected statements (PJM appendices, INL Revision 1 and the 2025 deck, the Henrico minutes, the PJM August 6 presentation, Transco, APG-576, Siemens and GE Vernova, Bloom, Fervo, the SCC final order, JLARC Table 3-1 and HTR-PM), and the engineering arithmetic in item 15. Three corrections were made: PJM's April 13, 2023 Elliott presentation gives 26.4% for firm-gas units, not 16%, so the April and July series are now stated separately (Section 5); Dominion's 2,970 MW and 1,099 MW components of the July 22, 2026 event sum to 4,069 MW, not its 3,869 MW net, so the components are no longer presented as a

decomposition (Sections 8, 15); and Fervo's commercial operation date is September 30, 2026, announced October 1 (Section 4). Both reviewers retrieved the SCC final order and quoted its GS-5 terms, including the four-year ramp option, which is now cited in Sections 3 and 14. Reviewer B could not reproduce the cost model's absolute levels without the workbook; that limitation is listed in Section 15. Verdicts: Reviewer A, confirmed on all items checked; Reviewer B, publishable as a technical working paper subject to the three corrections above, which are made.

Fifth round (citation audit)

All 43 hyperlinks resolved. Eight descriptions were tightened: the NRC document is a letter to Oklo, whose public text states that Oklo has no licensing application for Aurora-INL before the agency (the author and Reviewer A opened it; Reviewer B could not and suggested the NRC's Aurora pre-application page instead, which is consistent); the VDH citation now points to the SEH root-cause report as well as the response page; the JLARC citation links the full report; PJM's August 6, 2026 deck is titled "Dominion Load Transfer Event"; the NERC SAR is not labeled a draft; the INL decks are "Microreactor Annual Review" presentations; the sanitary survey's inspection and finalization dates are stated; and Williams' $1.5 billion figure is attributed to its project page rather than the 10-Q. Of the 36 legal, regulatory, standards and document citations, the reviewers confirmed 30 and corrected or qualified six, all applied: Va. Code § 56-596.7 (2026 Acts chs. 377, 378) sets a January 15, 2027 petition deadline and a November 30, 2027 order deadline and makes carbon-emitting generation ineligible for the flexibility program (opened and confirmed by the author; Sections 1, 8, 13, 14 revised); 6 U.S.C. § 124n was amended in December 2025 to extend limited counter-UAS authority to trained state and local law enforcement (Section 11 revised); NFPA 70B's current edition is 2026 and TIA-942's is 942-C (2024) (reference list revised); CMMC Level 2 assesses against SP 800-171 Rev. 2 (Section 11 revised); FERC's order in RD26-7-000 is dated July 16, 2026 (Sections 8, 10 revised); and the Macknick citation now names the NREL report and the 2012 journal article. Verdicts: Reviewer A confirmed every citation it reached; Reviewer B judged the citation apparatus adequate for an SSRN technical working paper once the flexibility-statute, counter-UAS, standards-edition and NRC items were resolved, which they are, and without a further general review.

Sixth round (nationwide and global sections)

Sections 16–18 were written after a research pass over 17 U.S. and global markets, and their 26 itemized factual claims were sent to both reviewers with the configuration conclusions and the options list. Reviewer A confirmed all 26 against primary sources, found no contradiction with the earlier sections, and asked for multi-day storage, hydrogen-capable engines and aggregated flexibility in the options menu (added). Reviewer B confirmed the regulatory chronology and corrected or qualified eleven points, all applied: FERC's co-location order offers four service choices, not three; Texas rule 16 TAC § 25.194 took effect October 8, 2026; New York's Executive Order 62 reaches applications not yet deemed complete; the Louisiana PSC order is dated August 29, 2025; Palisades' restart remains prospective; Germany's PUE 1.2 target is met within two years of start-up; Hydro-Québec's data center tariff is a proposal; Malaysia's PUE and WUE figures are incentive guidelines; Eurostat band IC is a ranking tool, not a hyperscale price; "transfers unchanged" was replaced with "same configuration, subject to local confirmation" and northern Virginia and Quebec were reclassified; the battery's "eligible everywhere" claim was restated as "excluded by no rule examined", with compliance and compensation to be established case by case; the geothermal exclusion now excepts the U.S. Great Basin; and the water conclusion was softened to "rarely decides siting". Reviewer B also asked for intermediate scale bands, thermal storage, flywheel UPS, staged energization, power capping, liquid-to-air units, hybrid heat rejection and high-voltage DC distribution in the menu (added). Verdicts: Reviewer A, publishable; Reviewer B, publishable once the three priority fixes (conditional transfer language, battery eligibility, geothermal exclusion) were made, which they are.

Seventh round (full pre-publication fact check)

The full text (Sections 1–18, Appendix A and the references) was sent to Reviewer B with five tasks: resolve the fourteen items left unverified in round six, fact-check every section, check internal consistency and arithmetic, list style defects, and give a publication verdict. Reviewer A received the open items as a focused verification list. Four separate research passes checked the U.S., European, Asian, Gulf and cost items, and the reviewers' new claims, against primary sources. Reviewer B's verdict was not ready for SSRN or the website until the Henrico design and economics were reconciled; Reviewer A

confirmed or corrected each open item. Each correction below was checked against a primary source, or a labeled secondary source, before it was applied.

Design and economics. Henrico's code confines data center generators to outages and testing, so the engines cannot energize the reference campus ahead of utility service; the early-energization offset is now limited to jurisdictions that permit primary onsite generation (Sections 1, 12, 13, Appendix A). The capacity credit is shown as contingent and the cost difference as an indicative $23–29/MWh between non-equivalent configurations. The W32 and W40 loop temperatures were separated: at W40 the chip-side supply rises to about 43°C. The battery is rated at half the campus peak, so the transfer sequence must shed or defer mechanical load until the engines accept it (Sections 9, 13, Appendix A). The comparison of grid-only and recommended configurations is now described as not like-for-like. The facility share of combined cost was corrected to about 41%; the microreactor cost multiple to about 1.5 to more than ten times; the liquid-fuel requirement was made consistent; and the 45% Uptime outage share was removed.

Facts corrected. Palisades fuel loading was paused on August 30, 2026 and the restart date is open. The Texas directive paused all TCEQ permits for data center projects, not only air permits; the Water Development Board was directed to enforce reporting rather than having begun enforcement; and Texas large-load security is the greater of $50,000/MW or allocated upgrade costs. Fervo reports more than 1 GW of binding contracts. Georgia's large-load pipeline is 73,100 MW within a 76,200 MW economic-development pipeline, and its rule permits contract terms of up to 15 years. MISO's ERAS is a generation interconnection process and LARS pairs large loads with new generation. The Abilene figures were restated without the unverified 360.5 MW and 1.4 GW values. Geothermal generation exists in seven western states, led by California. Oregon's rate class covers data processing facilities, and PacifiCorp's Schedule 401 update is what is pending. Nevada's September 2026 executive order, Oregon's state-land pause, Virginia's Rider T1 order and FERC's June 2026 rehearing order in the PJM co-location docket were added, and the exception at 40 CFR 60.4211(f)(3)(i) was described. Kashiwazaki-Kariwa 6 restarted February 9 and entered commercial operation April 16, 2026; OCCTO's 6.6 GW is an increment from new and expanded sites, now cited to OCCTO. Korea's assessment rule and KEPCO's 5 MW authority were attributed to their separate instruments. Humain's targets were updated and the Saudi tariff restated. Ireland's connection tiers and the October 27, 2026 effective date of its ride-through change were added. UK AI Growth Zones are selected on access to 500 MW, and the UK price was updated to Q2 2026. Statnett's change was dated and an unsupported queue total removed. The ACER, MCPD, EnEfG and Danish heat-reuse statements were qualified, figurative headings were replaced, and Henrico is no longer described as Northern Virginia.

Reviewer points not accepted. Reviewer B reported the cost chart and the four diagrams as missing; they are embedded in the document and appear in the exported files, and its text extract showed only placeholders. Its statements that MISO's filed LARS threshold is 250 MW, that the Georgia order is dated December 30, 2025, that Korea's assessment applies only in designated regions, that the Southaven permit issued on March 11, and that Singapore's September 2026 USEP had been published could not be confirmed and were not adopted.

Version 1.1 (October 24, 2026): changes since version 1.0

Four changes were made after the seventh review round, in response to its remaining findings and to the author's own list of weaknesses. None of them changes the paper's governing judgment.

1. Cost model rebuilt (Sections 1, 12, 13, 15; companion workbook). The three supply arrangements are now compared on a common reliability baseline: the same 5-minute lithium-ion UPS on the IT and CDU load, the same ride-through-rated cooling drives, transfer settings and electromagnetic-transient study, and 72 hours of liquid fuel for whichever backup fleet is installed. The grid bill is built from Dominion Energy Virginia's Schedule GS-4 transmission-voltage sheets and the riders in force on September 1, 2026, under the GS-5 minimum-billing provisions, instead of a flat energy price plus a PJM capacity charge; firm gas transportation and the gas lateral, which version 1.0 omitted, are costed; and the capacity credit is a scenario rather than the base case. The workbook, with every input in a labeled cell and every result a formula, and the Python script that reproduces it are published with the paper. The base-case difference between the recommended configuration and grid-only service with diesel backup is now $34/MWh (about $69 million a year), against the indicative $23–29/MWh of version 1.0.

Absolute levels rose for all three arrangements because the common baseline is now priced in each and the tariff-based bill ($84/MWh) is above the $80/MWh implied by version 1.0's energy price and capacity charge; the difference rose because firm gas transportation and the lateral are now costed and the base case carries no capacity credit. The cost chart was redrawn from the new outputs. After the eighth review round (item 5) the model became version 2.1: the Schedule GS-4 off-peak generation demand charge and Section IX billing-period proration were added, battery charging losses were repriced as energy drawn above energy delivered, and arrangement E's firm gas was reserved for the campus peak; the absolute levels rose by about $0.3/MWh and the difference by $0.1/MWh.

2. Climatic design data confirmed (Sections 6, 16.1, 17.3; workbook, Design conditions sheet). The approximate design temperatures of version 1.0 were replaced for 41 stations with the 2025 ASHRAE Handbook—Fundamentals annual 0.4% cooling design conditions distributed in the TMYx 2011–2025 design-day files, and the hours above the W32 and W40 dry-cooler limits were counted from each station's typical-year hourly file; every design-day file's header names the 2025 Handbook as its data source, and a station manifest and the counting script are published with the workbook. For Richmond the trim requirement is about 1,100 hours a year at W32 and 66 hours at W40, against the "several hundred hours" estimate in version 1.0. The largest temperature revisions were Salt Lake City (36 to 37.1°C), Houston (36.0 to 36.8°C) and Richmond (35.5 to 35.0°C).
3. Analytic standard applied. Section 1 now carries key judgments with a probability term and a separate confidence level and the evidence tier each rests on; Section 2 maps the paper's source labels to Sanctir's evidence tiers; Section 14 is restated as policy options with their consequences rather than recommendations. An abstract, keywords, JEL codes, ORCID, version, license and suggested citation were added for SSRN.
4. What did not change. The regional and international findings of Sections 16–18, the engineering content of Sections 5–11 and the review record of rounds 1–7 are as in version 1.0 except where the items above touch them. The remaining limits stated in Section 15 stand: no human practitioner review, equipment costs that are engineering estimates, no fault-tree or electromagnetic-transient study, GS-5 unit rates not yet filed, and several international items resting on reporting rather than primary documents.
5. Eighth review round (October 23–24, 2026). The changed sections, the tariff components and the model's inputs were sent to both reviewers, with web search. Both recomputed the model from the stated inputs and matched every figure within rounding; both confirmed every Schedule GS-4 rate, every rider rate and effective date, the GS-5 terms, the recovery of PJM capacity cost in base rates, and the seven JEL codes; Reviewer A confirmed that no GS-5 unit rates had been filed and checked Houston's design conditions against ashrae-meteo.info. Accepted and applied: Reviewer B's finding that the bill omitted the GS-4 off-peak generation demand charge ($0.558/kW on off-peak demand above 90% of on-peak demand; Sections II.B.2 and VII) and the Section IX proration of the schedule's charges by billing days over 30, both verified in the sheet and added (together about $0.6 million a year, $0.3/MWh, on A and C alike); that the deferred fuel cost charge is a uniform all-kWh charge on GS-4, not a system average (verified in the sheet filed June 15, 2026); that battery charging losses should be the energy drawn above the energy delivered and should also be charged to arrangement E; that E's firm transportation covered average rather than peak load; that Section 13 described arrangement A with evaporative cooling and weak ride-through while the model prices a common cooling and ride-through baseline (Section 12 now states the common cooling plant; the A row and the cost column are reworded); that the capacity-credit scenario prices the 60% floor at the full generation charge although Schedule GS-4 Section VIII.B.2 excludes PJM capacity expense when the floor controls (stated as an upper bound); that the uncapped-capacity case escalates the whole generation demand charge (labeled an upper-bound stress test, as Reviewer A also advised); that the Rider A increase is an assumption; that configuration C's renewable contract is not costed; that GS-5 takes in qualifying existing customers, with the term, ramp and collateral provisions attaching to agreements signed on or after January 1, 2027; that the Section 14 consequence on emergency hours overstated what DEQ can do under federal potential-to-emit rules; that the Section 14 non-advocacy sentence sat beside the author's assessment of unsupported positions; that the abstract ran to 252 words and made three categorical claims; that the Nordic row of Section 17.3 called W32 sufficient despite hours above the 27°C limit; that few trim hours do not imply small trim capacity; that Rider D and the Rider CE and RPS exemption assumption should be stated; and that the climate values needed a provenance record (all 41 design-day files were re-opened on October 24, 2026, each header naming the 2025 Handbook; the manifest and script are published). Key judgments were recalibrated in part: the ride-through judgment now carries two

probabilities, the permit judgment's confidence fell to low, and the cost judgment's confidence is split between the direction and the size of the difference. Not accepted: lowering the electricity-before-water judgment below almost certain (its Tier 1 evidence is direct and consistent); making arrangements A and C identical in cooling (they are distinct designs; the model prices a common cooling plant and now says so); and Reviewer B's view that the high-gas result was misstated (its figure omitted the pricing of battery losses at the high-gas energy rate, a convention Section 12 now states). Reviewer A's note that "Microsoft appealed" was imprecise applied to the review prompt, not to the paper. Net effect: arrangement A $102.9 to $103.2/MWh, C $137.1 to $137.4, E $109.1 to $109.4; the base-case difference $34.2 to $34.3/MWh. Asked to grade the corrected text, Reviewer A gave A– and said it was ready to post; Reviewer B gave B+ and withheld a yes on one point, that arrangement A was described as having "no islanding" when a diesel-backed campus also runs islanded during an outage, so the capability C buys is grid-forming transfer, fuel diversity and endurance rather than islanding as such. Accepted: the abstract, Sections 1, 12 and 13 now describe the difference as how the island is formed and how long it can be held. Both named the same remaining requirements for a peer-reviewed journal: OEM or utility-validated costs, site-specific electromagnetic-transient and fault-tree results, a capacity component isolated inside the generation demand charge, primary documents for the remaining Tier 3 international items, and an independently re-runnable data appendix.

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