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Merger Buildout Outlook

The proposed NextEra–Dominion combination is not a near-term power unlock for East Coast datacenters.

Executive Summary

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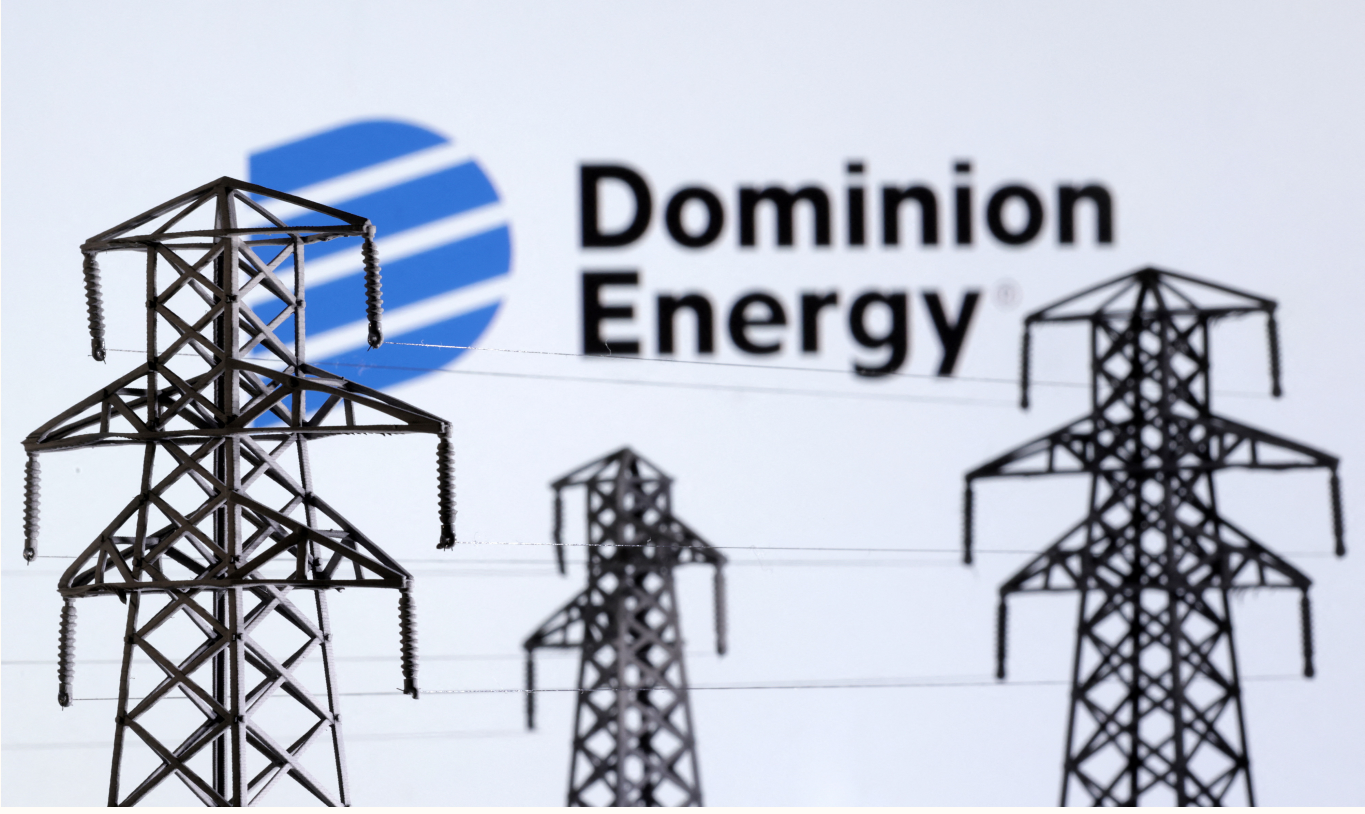

Page-one verdict

The proposed NextEra–Dominion combination is not a near-term power unlock for East Coast datacenters. It is a plausible late-decade capital and procurement accelerator—and an even more plausible siting redistribution event—if regulators approve the transaction without conditions that trap capital inside state-by-state ring fences or force every incremental large-load upgrade into customer-specific proceedings.

The best site answer for power, schedule, connectivity, and cost is Richmond–Henrico / selected Chesterfield, not Loudoun. Loudoun / Northern Virginia remains the East Coast's best connectivity market and will retain the highest-value latency- and ecosystem-sensitive workloads. But for incremental large-load growth, Richmond–Henrico offers the better balance: stronger land and logistics flexibility than Loudoun, meaningful 230 kV / 500 kV corridor adjacency in the broader Richmond-Chesterfield grid, less saturated local politics, and better water/environmental posture than Southside Virginia, Charlotte/RTP, or the broader PJM/SERC seam. Columbia/Cayce in Dominion Energy South Carolina territory is the most credible Carolinas pressure-release market, but it is a second-wave recommendation because South Carolina ratepayer politics and discharge permitting must be solved first.

The single biggest risk to that recommendation is regulatory cost allocation. The Virginia State Corporation Commission, North Carolina Utilities Commission, South Carolina Public Service Commission, FERC, HSR agencies, and NRC can approve the deal only with conditions that protect customers, ring-fence utilities, require direct assignment of datacenter-driven infrastructure costs, or slow capital deployment. Those conditions are rational; they may also neutralize much of the merger's claimed buildout acceleration. Virginia is already moving that way: the Virginia SCC says certain large-scale customers must pay at least 85% of contracted distribution and transmission demand and 60% of generation demand to help insulate other customers from datacenter-driven infrastructure costs (Virginia SCC, 2025 biennial review order release: https://www.scc.virginia.gov/about-the-scc/newsreleases/release/scc-issues-order-on-dev-biennial-review-2025/scc-rules-in-dev-biennial-review-case.html).

Five findings drive the call:

1. The transaction is signed, not closed. NextEra and Dominion announced a definitive all-stock combination on May 18, 2026; Dominion shareholders would receive 0.8138 NextEra shares per Dominion share, with expected post-close ownership of roughly 74.5% NextEra shareholders / 25.5% Dominion shareholders (NextEra announcement: https://newsroom.nexteraenergy.com/2026-05-18-NextEra-Energy-and-Dominion-Energy-to-Combine,-Creating-the-Worlds-Largest-Regulated-Electric-Utility-Business-and-North-Americas-Premier-Energy-Infrastructure-Platform-Benefiting-Customers?l=12). The SEC Form 8-K identifies an agreement date of May 15, 2026, a two-step merger structure,

required state and federal consents, an outside date of November 15, 2027, and a Dominion termination fee of $2.24 billion (NextEra SEC Form 8-K: https://www.sec.gov/Archives/edgar/data/753308/000110465926063001/tm2614888d1_8k.htm).

2. Demand stress is real before the deal enters the story. PJM's 2025 long-term forecast projects RTO winter peak load of 198,175 MW in 2034/35 and projected energy growth averaging 4.8% per year over the 10-year period (PJM 2025 Long-Term Load Forecast: https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf). Dominion's 2024 IRP release says PJM forecasts "unprecedented" power-demand growth, while Dominion's own large-load process states that new datacenters above 50 MW will most likely require transmission-line extensions and a new substation (Dominion IRP release: https://news.dominionenergy.com/press-releases/press-releases/2024/Dominion-Energy-Virginia-releases-comprehensive-long-term-plan-to-meet-growing-power-demand-with-reliable-affordable-and-increasingly-clean-electricity-10-15-2024/default.aspx; Dominion data center requests page: https://www.dominionenergy.com/en/Virginia/Large-Business-Services/Data-Center-Requests).

3. The bull case is credible but narrower than the market narrative. NextEra brings development scale, procurement leverage, a lower perceived capital-friction profile, and a large renewables/storage platform. Its March 2025 investor materials cite a renewables and storage backlog of more than 25 GW and an opportunity to develop 36.5–46.5 GW of renewables and storage through 2027 (NextEra March 2025 investor deck: https://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/news-and-events/events-and-presentations/2025/2025 March Investor Deck.pdf). Dominion is not capital-starved in the no-merger case: its 2025 annual report points to $65 billion of capital investment through 2030 (Dominion 2025 Annual Report: https://www.sec.gov/Archives/edgar/data/715957/000119312526115192/dei-ars-12312025.pdf). The merger's incremental value is therefore execution quality and capital optionality, not turning a no-build utility into a builder.

4. The physical constraints do not merge away. PJM's 2026/2027 capacity auction cleared at the approved cap of $329.17/MW-day (PJM 2026/2027 BRA report: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf). PJM's interconnection reform process began with roughly 200,000 MW of projects, with transition processing continuing through 2025–2026 (PJM Inside Lines: https://insidelines.pjm.com/new-fact-sheet-highlights-interconnection-process-reform-progress/). DOE's large-power-transformer resilience report identifies long lead times and limited spare availability as a critical infrastructure concern (DOE Large Power Transformer Resilience Report: https://www.energy.gov/sites/default/files/2024-10/EXEC-2022-001242 - Large Power Transformer Resilience Report signed by Secretary Granholm on 7-10-24.pdf). These are the actual gates for megawatts.

5. Redistribution is more likely than net acceleration. Reference-class records from Northern Virginia datacenter cases show that rising power demand becomes a local political issue—lines, substations, bills, climate targets, noise, water, and visual impacts—not merely a corporate capital issue. Comparable hyperscale-grid precedents also show that a single major datacenter load can require new 500 kV transmission and substation facilities, with large system-improvement cost exposure. That reference class supports the central conclusion: the merger can change who has balance-sheet control and where capital is steered, but it cannot make a constrained load pocket unconstrained.

The MW and schedule ranges in this analysis are strategic scenario bands versus Dominion standalone, not engineering forecasts or committed utility capacity. They are bounded by public facts that point in opposite directions: Dominion already has a $65 billion capital program through 2030, NextEra brings a much larger development and procurement platform, and the actual energization bottlenecks remain transmission extensions, new substations, PJM deliverability, capacity-market tightness, transformer availability, commission approvals, and large-load cost allocation.

1. Why the question exists now

The East Coast datacenter buildout question exists because demand, grid infrastructure, and local politics have moved onto different clocks. Datacenter construction can move in roughly two years when power is ready; generation, transmission, substation, transformer, and regulatory approvals usually do not. PJM's 2025 forecast, Dominion's 50 MW large-load threshold, and recent PJM capacity-market pricing all point in the same direction: the market is not debating whether demand exists; it is debating whether firm deliverable capacity can be created at the places and dates hyperscalers want.

Northern Virginia remains the densest datacenter ecosystem in the world. Dominion's 2024 annual report called Northern Virginia "the world's largest data center market by far," larger than the next five largest U.S. markets combined (Dominion 2024 Annual Report: https://www.sec.gov/Archives/edgar/data/715957/000095017025046342/dei-ars-12312024.pdf). That concentration creates the familiar flywheel—fiber density, cloud ecosystems, specialized contractors, experienced utilities, and the credibility of already-operating campuses. It also creates its own limit. Dominion's public large-load page is blunt: serving new datacenters above 50 MW will most likely require new transmission extensions and a new substation (Dominion data center requests page: https://www.dominionenergy.com/en/Virginia/Large-Business-Services/Data-Center-Requests). For the AI-era loads now being discussed, that is not an edge case; it is the core case.

The system-wide pressure is no longer theoretical. PJM's 2025 Long-Term Load Forecast projects winter peak demand of 198,175 MW in 2034/35 and energy growth averaging 4.8% annually over the decade (PJM 2025 Long-Term Load Forecast: https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf). PJM capacity prices have reflected the tightening system: the 2026/2027 Base Residual Auction cleared all prices at the approved cap of $329.17/MW-day (PJM 2026/2027 BRA report: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf). NERC's long-term reliability assessment warns that demand-growth projections are outpacing planned resource additions, creating projected winter resource shortfalls in some areas (NERC Long-Term Reliability Assessment: https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf).

That is the market into which the NextEra–Dominion proposal lands. The deal thesis is not that demand needs to be stimulated. Demand is already there. The thesis to test is whether NextEra ownership can create more firm deliverable megawatts per year, at lower delivered cost, on a faster energization schedule, than Dominion could deliver alone.

The answer is conditional and asymmetric. NextEra can plausibly improve capital formation, procurement, development execution, and generation origination. But firm datacenter service is determined by the combination of accredited capacity, local transmission deliverability, substations, transformers, large-load tariffs, local permits, and community acceptance. Ownership helps only after those gates are open.

2. Transaction terms: what is signed, what is not

The signed deal is a stock-for-stock utility combination. NextEra and Dominion announced on May 18, 2026 that they had entered into a definitive agreement to combine; Dominion shareholders would receive 0.8138 shares of NextEra common stock for each Dominion share, and the companies said closing was expected in 12–18 months, subject to approvals (NextEra announcement: https://newsroom.nexteraenergy.com/2026-05-18-NextEra-Energy-and-Dominion-Energy-to-Combine,-Creating-the-Worlds-Largest-Regulated-Electric-Utility-Business-and-North-Americas-Premier-Energy-Infrastructure-Platform-Benefiting-Customers?l=12). The SEC Form 8-K states that the merger agreement was dated May 15, 2026, uses a two-step merger structure, requires Dominion shareholder approval by a majority of outstanding Dominion shares, identifies HSR, FERC, NRC, Virginia SCC, North Carolina Utilities Commission, and South Carolina PSC consents, and sets an outside date of November 15, 2027 (NextEra SEC Form 8-K: https://www.sec.gov/Archives/edgar/data/753308/000110465926063001/tm2614888d1_8k.htm).

The transaction therefore sits in the category most prone to false certainty: strategically persuasive, publicly announced, but approval-dependent. The exchange ratio is fixed; the value fluctuates with NextEra's stock. The companies' claimed customer benefits and affordability commitments are claims until translated into enforceable commission orders. The datacenter-buildout thesis is even more attenuated: neither an exchange ratio nor a corporate headquarters commitment energizes a 100 MW campus.

The regulatory approval list is the first-order analytical issue:

- Virginia SCC. Virginia Code §56-88.1 requires SCC approval for acquisition or disposition of control of a public utility and provides a 60-day decision clock after a completed application, extendable by order up to 120 additional days (Virginia Code §56-88.1: https://law.lis.virginia.gov/vacode/title56/chapter5/section56-88.1/). Virginia is the highest-stakes jurisdiction because Dominion Virginia serves the core datacenter load pocket.
- North Carolina Utilities Commission. N.C. Gen. Stat. §62-111 requires written commission approval for mergers or combinations affecting a public utility and allows the commission to impose conditions necessary under the public convenience and necessity standard (N.C. Gen. Stat. §62-111: https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_62/GS_62-111.pdf).
- South Carolina PSC. The SEC Form 8-K lists South Carolina PSC consent as a closing condition (NextEra SEC Form 8-K: https://www.sec.gov/Archives/edgar/data/753308/000110465926063001/tm2614888d1_8k.htm). South Carolina will matter because Dominion Energy South Carolina and the Cayce operating-headquarters commitment are part of the regional story.
- FERC §203. FERC review focuses on the effect of a transaction on competition, rates, regulation, and cross-subsidization (FERC merger information: https://www.ferc.gov/electric/general-information/mergers-and-sections-201-and-203-transactions).
- HSR / DOJ-FTC. The FTC describes the ordinary HSR waiting period as generally 30 days, with additional process if a Second Request is issued (FTC premerger review guidance: https://www.ftc.gov/advice-guidance/competition-guidance/guide-antitrust-laws/mergers/premerger-notification-merger-review-process).
- NRC. NRC approval is required before direct or indirect transfer of control of an NRC license; the review covers financial qualifications, technical capability, organizational control, and decommissioning funding (NRC license transfers and mergers: https://www.nrc.gov/reactors/operating/licensing/license-transfers-mergers).

A clean approval path could close within the companies' 12–18 month window. A conditioned path extends into early 2028. A heavily contested path creates deal-break or repricing risk. The practical schedule bands for buildout should therefore be anchored not to the announcement date, but to the date when commissions approve a capital, tariff, and ring-fencing framework that can support large-load service commitments.

3. The strongest bull case

The strongest bull case deserves to be taken seriously. NextEra is not just a financial buyer. It owns Florida Power & Light, one of the largest regulated utilities in the U.S., and NextEra Energy Resources, a scaled renewables, storage, and power-development platform. Its investor materials cite more than 25 GW of renewables and storage backlog and a 36.5–46.5 GW development opportunity through 2027 (NextEra March 2025 investor deck: https://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/news-and-events/events-and-presentations/2025/2025 March Investor Deck.pdf). In an industry constrained by equipment, interconnection queues, capital discipline, and execution bandwidth, a sponsor with repeatable procurement and development machinery matters.

The bull case has four components:

1. Capital formation. Dominion already has a large capex plan—$65 billion through 2030 in the 2025 annual report—but a combined NextEra-Dominion platform may lower friction around funding, procurement, and sequencing (Dominion 2025 Annual Report: https://www.sec.gov/Archives/edgar/data/715957/000119312526115192/dei-ars-12312025.pdf).
2. Procurement leverage. Large-power transformers, breakers, turbines, and substation equipment are schedule-critical. DOE identifies transformer lead times and spare availability as a resilience concern (DOE Large Power Transformer Resilience Report: https://www.energy.gov/sites/default/files/2024-10/EXEC-2022-001242 - Large Power Transformer Resilience Report signed by Secretary Granholm on 7-10-24.pdf). A larger buyer with better procurement discipline can improve odds of securing equipment slots.
3. Generation origination. NextEra's renewables/storage backlog can help match hyperscaler clean-energy commitments. That does not automatically create local firm service, but it gives large-load buyers more structured procurement pathways than a standalone local utility may offer.
4. Portfolio steering. A combined platform spanning Virginia and South Carolina, adjacent to the Carolinas and the PJM/SERC seam, could steer marginal loads away from the most congested pockets and toward sites where land, community acceptance, water, and transmission can be solved together.

If all four are true, the merger could increase incremental firm deliverable MW by the late 2020s. The ranges are best read as scenario bands against the Dominion-standalone counterfactual. In a clean-approval scenario, 350–700+ incremental firm MW per year is plausible as an upper strategic band once approved capital programs, substations, equipment, and service agreements are in motion. That band is roughly the equivalent of three to seven

100 MW campus phases, or a larger number of partial ramps, not a claim that 350–700 MW is sitting unused in Northern Virginia. It requires capital availability, interconnection readiness, substation siting, transformer procurement, transmission deliverability, and commission-approved cost allocation to line up.

In a conditioned-approval scenario, 100–300 incremental firm MW per year is the more defensible band: roughly one to three 100 MW campus phases, or equivalent phased ramps, where procurement and execution improve but ratepayer-protection conditions, ring-fencing, direct assignment of upgrade costs, and customer-specific proceedings consume much of the theoretical capital advantage. Before closing, the transaction-attributable increment is effectively zero.

That is the fair bull case. It is not a case for immediate NoVA relief.

4. The constraint case: what ownership does not solve

The constraint case is stronger in the near term. It begins with the mechanics of serving a datacenter.

A 50 MW-plus datacenter request is not simply a customer-service request. Dominion says those loads will most likely require transmission extensions and a new substation (Dominion data center requests page: https://www.dominionenergy.com/en/Virginia/Large-Business-Services/Data-Center-Requests). Those assets need routing, land rights, materials, protection systems, commissioning, and cost recovery. For larger campuses, the question becomes whether generation capacity, transmission deliverability, transformers, substations, and local permits line up in the same window.

PJM interconnection reform helps process the generator side of the equation, but it does not make all resources deliverable to all load pockets. PJM's public interconnection-reform update describes a transition process that began with approximately 200,000 MW of projects and remaining projects to be processed through 2025 and 2026 (PJM Inside Lines: https://insidelines.pjm.com/new-fact-sheet-highlights-interconnection-process-reform-progress/). PJM's capacity auction results demonstrate a tight resource-adequacy environment, not excess headroom (PJM 2026/2027 BRA report: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf).

The transformer and turbine supply chain adds another hard edge. DOE's large-power-transformer report is explicit that long lead times and limited spare availability can affect critical infrastructure resilience (DOE Large Power Transformer Resilience Report: https://www.energy.gov/sites/default/files/2024-10/EXEC-2022-001242 - Large Power Transformer Resilience Report signed by Secretary Granholm on 7-10-24.pdf). Gas generation, if used as a

firming or bridge-power path, also faces turbine availability, air permitting, gas transportation, and emissions constraints. Behind-the-meter and bridge-power strategies can improve commissioning certainty for phased ramps, but they are not substitutes for permanent firm utility service.

This is where the public narrative often becomes too loose. A NextEra-owned Dominion could originate more generation and sign more PPAs. But a PPA is not a substation. A renewable backlog is not local transmission deliverability. Corporate ownership is not a county zoning approval. The merger improves the tool kit; it does not eliminate the job.

5. Submarket scorecard

RANK	SUBMARKET	POWER	SCHEDULE	CONNECTIVITY	COST	COMMUNITY / REGULATORY	WATER / ENVIRONMENTAL	VERDICT
1	Richmond–Henrico / selected Chesterfield	Strongest balanced Virginia lane; 230/500 kV regional infrastructure and late-decade gas/utility optionality	Better than NoVA if parcels hug existing corridors	Good; not NoVA-grade but sufficient for many workloads	Better than NoVA	Elevated, manageable under Henrico design rules and large-load cost-allocation scrutiny	Best Virginia water screen if floodplain/wetlands are avoided	Best overall recommendation
2	Loudoun / NoVA	Dense infrastructure but saturated local deliverability	Weak for new 50 MW+ loads requiring lines/substations	Best in class	Worst	High opposition and zoning friction	Infrastructure-rich but politically sensitive water/land-use screen	Keep for premium connectivity-critical demand
3	Columbia / Cayce / Dominion SC	Promising within Dominion SC, not a Virginia substitute	Moderate; commission and discharge timing matter	Good regional option	Better than NoVA	Moderate-to-elevated due rate cases and SC PSC/ORS scrutiny	Strong raw water posture, discharge complexity	Best Carolinas pressure-release node
4	Southside / Mecklenburg VA	Some 500 kV regional presence but thinner local high-voltage density	Parcel- and upgrade-dependent	Weaker than Richmond/NoVA	Attractive land	Moderate-to-elevated; rural water/line risk	Drought-sensitive under evaporative cooling	Selective, not first-choice
5	Charlotte / RTP	Mostly Duke-controlled; limited direct transaction synergy	Utility-specific	Strong metro infrastructure	Moderate	Elevated ratepayer-policy risk emerging	Drought/flood constraints under hybrid evaporative cooling	Useful market, weak direct merger linkage

RANK	SUBMARKET	POWER	SCHEDULE	CONNECTIVITY	COST	COMMUNITY / REGULATORY	WATER / ENVIRONMENTAL	VERDICT
6	Broader PJM/SERC seam	Strategic but not bankable without local proof	Uncertain	Node-specific	Potentially attractive	Elevated multi-jurisdictional risk	Danville-type proxies show drought/flood limits	Option value only

Why Richmond–Henrico wins

Richmond–Henrico wins because it is the best compromise market. It does not beat Loudoun on fiber ecosystem. It does not beat Southside on land cost. It does not beat Columbia/Cayce on Carolinas diversification. It wins because the four priorities—power, schedule, connectivity, and cost—must be optimized together, and Richmond–Henrico is the least-bad balance.

Power-side analysis shows the broader Richmond–Henrico/Chesterfield area has meaningful bulk-grid adjacency. Henrico and Chesterfield screens identify 500 kV maximum-voltage infrastructure in the broader 15-mile region, and Chesterfield has active PJM queue evidence for large gas projects projected around 2029. Those data points do not create bankable service by themselves, but they make Richmond the most plausible Virginia beneficiary of a late-decade combined-company execution push. Site/logistics screening also favors Henrico corridor sites: flat topography at the representative point, transmission proximity within two miles, rail density, and an adopted county data-center design framework.

Water/environmental review gives Richmond–Henrico the strongest Virginia posture if parcels avoid the James River / Chickahominy floodplain and wetland network. Henrico's representative screen showed low current drought severity, no designated critical habitat within one mile, and no impaired waters identified within 10 km, though floodplain and NWI wetland features still require parcel-level avoidance. That is a manageable constraint set compared with Southside's drought signal, Charlotte/RTP's drought and floodplain profile, and Danville's Dan River floodplain exposure.

Community/political review also points to Richmond–Henrico as the best pressure-release lane. Henrico adopted a Data Center Comprehensive Plan Amendment on June 10, 2025 and requires design expectations such as noise studies before site plan approval (Henrico County Data Center Design Guidelines: https://henrico.gov/public-data/data-center-design-guidelines/; adopted amendment PDF: https://henrico.gov/pdfs/planning/datacenters/DataCenterGuidelinesComprehensivePlanAmendment.Adopted.6.10.25.pdf). That is regulation, not absence of regulation. But it is more investable than a saturated market where opposition has become a general political identity.

The caution is important: Richmond–Henrico is recommended as a corridor strategy, not a county-wide green light. The wrong cheap greenfield parcel in Chesterfield can lose the entire advantage by requiring a long lateral, new substation, added wetland mitigation, or heavier grading. The right parcel is close to existing high-voltage corridors, buffered from residences, above floodplain, compatible with Henrico-style design standards, and connected to municipal or reclaimed-water pathways.

Why Loudoun does not win

Loudoun remains essential. It simply no longer scores best for marginal growth. The Ashburn proxy shows dense transmission adjacency, gentle topography, and the deepest connectivity ecosystem. That is why the market exists. But Loudoun County's public materials show a marked shift toward stricter datacenter controls. On March 18, 2025, the Loudoun County Board of Supervisors adopted comprehensive plan and zoning ordinance amendments placing new controls on data-center development, and county materials describe conditional-use treatment in the 2019 General Plan (Loudoun County Phase 1 project plan: https://www.loudoun.gov/6221/Phase-1-Project-Plan-for-Data-Center-Sta; Loudoun data centers page: https://www.loudoun.gov/6188/Data-Centers-in-Loudoun-County). Community opposition is not incidental; it is now part of the entitlement environment.

Loudoun should be treated as a premium, capacity-constrained market. It is the right answer for workloads where ecosystem and latency justify high cost, longer energization timelines, and more public scrutiny. It is not the right answer for a generic new 100–300 MW campus seeking the fastest and cheapest path to firm power.

Why Columbia/Cayce is the Carolinas pick

The Carolinas are not one market. Charlotte and RTP are primarily Duke lanes. Columbia/Cayce is the more direct transaction-relevant market because Dominion Energy South Carolina is inside the Dominion platform and the SEC record includes a Cayce operating-headquarters commitment (NextEra SEC Form 8-K: https://www.sec.gov/Archives/edgar/data/753308/000110465926063001/tm2614888d1_8k.htm). Water screening also favors Columbia/Cayce relative to Charlotte and RTP: Richland County had lower current drought severity in the representative screen, and the Congaree River gauge read 3,680 cfs at the time of assessment via USGS NWIS (USGS Water Data: https://waterdata.usgs.gov/nwis). The limiting issue is discharge and ratepayer politics. The water-quality screen identified many listed water bodies within 10 km, so blowdown routing and NPDES treatment are front-end issues. Separately, the South Carolina Office of Regulatory Staff has published consumer information on a Dominion Energy South Carolina request for an approximately 12.73% rate increase that would raise an average 1,000-kWh residential bill by about $19.98 per month if

approved (SC ORS: https://ors.sc.gov/news/ors-releases-consumer-information-dominion-energy-south-carolina-inc-desc-request-rate-1). That backdrop makes datacenter-related capital politically sensitive.

Columbia/Cayce is therefore the best Carolinas pressure-release candidate, but not a first-wave substitute for Richmond–Henrico.

6. Scenarios: what changes versus Dominion standalone

Scenario A — blocked or collapsed transaction

If the transaction is blocked, abandoned, or materially repriced, the incremental merger effect is zero by definition. Dominion still has a large standalone capital plan—$65 billion through 2030—but datacenter service remains governed by Dominion's existing queueing, transmission, substation, tariff, and local approval processes (Dominion 2025 Annual Report: https://www.sec.gov/Archives/edgar/data/715957/000119312526115192/dei-ars-12312025.pdf). In this scenario, Northern Virginia remains dominant for connectivity, but marginal demand continues to leak toward Richmond, Southside, the Carolinas, Ohio-type markets, and other lower-friction locations because the core market is constrained.

Incremental firm MW/year versus no-merger: 0.
Delivered $/MW effect: no transaction-driven reduction.
Time-to-energization effect: no transaction-driven improvement.

Scenario B — approval with material conditions

This is the most realistic planning case. State commissions approve the transaction but impose ring-fencing, affiliate-transaction rules, reporting, customer credits, minimum demand obligations, direct assignment of infrastructure costs, and large-load tariff protections. These conditions protect households and small businesses. They also reduce capital fungibility.

Under this case, the merger can improve procurement and coordination, but large-load customers fund a substantial share of marginal upgrades. A strategic range of 100–300 incremental firm MW/year by the late 2020s is defensible where named substation, transformer, transmission, and customer-contribution plans exist. The logic is modest uplift, not step-change: Dominion's standalone $65 billion plan means there is already a build program, while Virginia-style large-load cost assignment, state ring-fencing, and customer-specific proceedings can blunt much of the merger's capital advantage. The range is therefore sized

around one to three 100 MW campus phases, or equivalent partial ramps, that benefit from better procurement and execution without assuming unconstrained deliverability.

Incremental firm MW/year versus no-merger: roughly 100–300 after approvals and committed projects.
Delivered $/MW effect: neutral to higher for datacenter customers, because ratepayer protection shifts costs to large loads.
Time-to-energization effect: neutral to modestly better for corridor-ready sites; slower for projects caught in tariff or ring-fencing proceedings.

Scenario C — clean or condition-light approval

This is the bull case. The transaction closes inside the companies' 12–18 month window; regulators accept enforceable but not capital-paralyzing commitments; NextEra's procurement/development engine improves project sequencing; and Dominion's load-serving territories become a larger platform for generation and grid investment.

Even here, the benefits are late-decade. A strategic range of 350–700+ incremental firm MW/year is plausible only where service agreements, substations, transformers, and deliverability are aligned. The defense is execution capacity: NextEra's 25 GW-plus renewables and storage backlog and 36.5–46.5 GW development opportunity show development scale, while Dominion's standalone capital plan shows a substantial base to accelerate from rather than replace. The cap on the range is equally important. A 350–700+ MW/year increment requires multiple 100 MW-class phases or equivalent ramps to clear transmission, substation, transformer, deliverability, tariff, and local-permitting gates in the same window. It is not immediately available NoVA capacity.

The same boundary applies to schedule. A 6–12 month improvement is reasonable for the best-prepared projects—sites with land control, corridor adjacency, a credible substation path, mature utility engagement, procurement visibility, and tariff or cost-allocation readiness. It is not a general shortcut for projects that still need long-lead transmission corridors, contested zoning, uncertain PJM deliverability, or unresolved commission treatment.

Incremental firm MW/year versus no-merger: roughly 350–700+ after approvals and project mobilization.
Delivered $/MW effect: modest improvement possible through procurement and financing, but only where customer-funded infrastructure does not dominate.
Time-to-energization effect: 6–12 months faster for the best-prepared projects; no improvement for sites needing new long-lead transmission corridors.

7. Who wins and who loses

Hyperscalers and large-load buyers gain optionality, not guaranteed cheaper power. The smart move is to underwrite sites by firm utility deliverability, not by corporate merger narrative. Buyers should maintain NoVA for workloads that require the ecosystem and pursue Richmond–Henrico, Columbia/Cayce, and selected low-friction nodes for growth that can tolerate more distance from the core.

Datacenter developers and powered-land aggregators should bank corridor-proximate Richmond–Henrico parcels and be selective in Chesterfield, Southside, and the seam. A parcel with cheap land but no nearby high-voltage route is not powered land; it is a grid-development project with a land option attached.

Infrastructure investors gain from contracted generation, storage, substations, transformers, bridge-power solutions, and customer-funded network upgrades. The risk is underwriting the deal as if clean approval and socialized cost recovery are guaranteed. They are not.

Dominion and NextEra shareholders gain if the combined platform converts load growth into approved regulated capital and contracted infrastructure margin. They lose if commissions approve the transaction only with conditions that cap affiliate benefits, require customer credits, or isolate state utilities from capital synergies.

Ratepayers need the deal to be boring: ring-fenced, transparent, and built around cost causation. Virginia's 85% / 60% minimum-demand approach is a template for making datacenter customers absorb the risk of speculative or oversized infrastructure (Virginia SCC: https://www.scc.virginia.gov/about-the-scc/newsreleases/release/scc-issues-order-on-dev-biennial-review-2025/scc-rules-in-dev-biennial-review-case.html). North Carolina and South Carolina are likely to ask analogous questions through their own statutory and commission frameworks.

Regulators should treat the buildout thesis as a testable claim. Approval conditions should ask: Which named projects create incremental firm deliverable MW? Which customers pay if load forecasts miss? Which upgrades are needed for reliability independent of datacenters? Which costs are direct-assigned? Which commitments survive if the AI load cycle slows?

8. What to watch

The leading indicators are concrete:

1. Virginia SCC filing and settlement posture. If the application offers detailed large-load cost assignment, ring-fencing, reliability reporting, and customer-contribution terms, approval risk falls. If it leans on generalized affordability rhetoric, approval risk rises.
2. FERC §203 conditions. FERC's treatment of cross-subsidization, market power, and affiliate transactions will signal whether the combined company can use scale freely or must operate through tighter guardrails (FERC merger information: https://www.ferc.gov/electric/general-information/mergers-and-sections-201-and-203-transactions).
3. NRC timing. Nuclear-license transfer approval is not the datacenter story, but it can be on the transaction critical path (NRC: https://www.nrc.gov/reactors/operating/licensing/license-transfers-mergers).
4. Named transmission and substation projects. The market should discount any claimed MW acceleration not tied to named substations, transformer slots, transmission routes, in-service dates, and customer service agreements.
5. PJM capacity and queue updates. Tight capacity prices and slow deliverability processing reduce the merger's practical effect; faster queue processing and credible new resources improve it (PJM auction report: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf; PJM interconnection reform update: https://insidelines.pjm.com/new-fact-sheet-highlights-interconnection-process-reform-progress/).
6. Local rulemaking in Loudoun and Henrico. Loudoun's conditional-use framework and Henrico's design guidelines will determine whether the recommended redistribution lane can absorb demand without recreating NoVA's backlash (Loudoun: https://www.loudoun.gov/6188/Data-Centers-in-Loudoun-County; Henrico: https://henrico.gov/public-data/data-center-design-guidelines/).
7. South Carolina rate cases and ORS posture. Columbia/Cayce becomes more attractive if Dominion Energy South Carolina can demonstrate that datacenter-related upgrades are customer-funded and not residential bill drivers (SC ORS: https://ors.sc.gov/news/ors-releases-consumer-information-dominion-energy-south-carolina-inc-desc-request-rate-1).

9. Outlook

The headline is not “NextEra buys Dominion and unlocks Data Center Alley.” That is too easy and likely wrong. The better headline is: NextEra–Dominion can change the map of East Coast datacenter growth, but only after regulators decide who pays for the grid that AI requires.

The most likely outcome is a conditioned approval path that preserves the deal’s strategic rationale but narrows the datacenter upside. In that world, NoVA stays dominant but sheds marginal growth. Richmond–Henrico / selected Chesterfield becomes the best-balanced Virginia expansion lane. Columbia/Cayce becomes the most interesting Dominion-linked Carolinas node. Southside Virginia and the PJM/SERC seam remain option-value markets that need parcel- and utility-specific proof. Charlotte and RTP remain important Carolinas markets, but not because the NextEra–Dominion transaction directly controls their utility destiny.

The acquisition can accelerate buildout only where three things happen together: regulators approve a workable cost-allocation framework; the combined platform secures transformers, substations, transmission, and capacity earlier than Dominion standalone; and large-load customers accept take-or-pay, collateral, and direct infrastructure obligations sufficient to protect other ratepayers.

Until those conditions are visible in filings and orders, the right underwriting stance is skeptical but not dismissive: treat the merger as a late-decade redistribution and execution story, not a near-term megawatt machine.