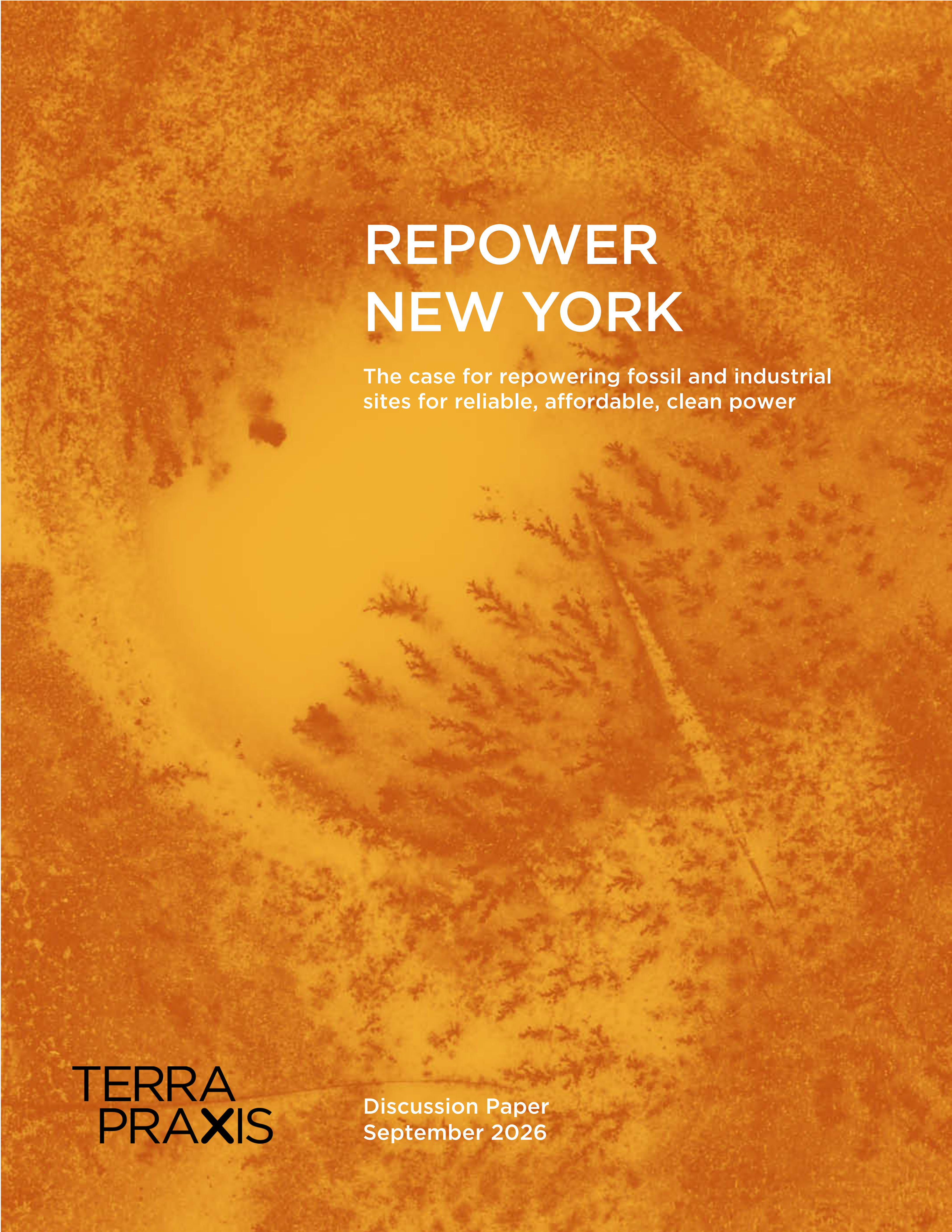

REPOWER NEW YORK

The case for repowering fossil and industrial sites for reliable, affordable, clean power

TERRA PRAXIS

Discussion Paper
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CONTENTS

ACRONYMS AND UNITS

ABWR	Advanced Boiling Water Reactor
ACT	Automated Configuration Technology (the Terra Praxis automation platform)
ANZEC	Advanced Nuclear Zero Emission Credit
AP1000	Westinghouse 1,100 MW-class pressurized-water reactor design
APR-1400	Korean 1,400 MW-class pressurized-water reactor design
BWRX-300	GE Vernova Hitachi boiling-water SMR design (300 MW class)
CGPP	Coordinated Grid Planning Process
CLCPA	Climate Leadership and Community Protection Act (New York, 2019)
CWIP	construction work in progress (utility-ownership financing provision)
DEC	New York State Department of Environmental Conservation
DOE	U.S. Department of Energy
DPS	New York State Department of Public Service
ENEC	Emirates Nuclear Energy Corporation
EPC	engineering, procurement, and construction
EPRI	Electric Power Research Institute
FID	final investment decision
FOAK	first-of-a-kind
IAEA	International Atomic Energy Agency
IBEW	International Brotherhood of Electrical Workers
KEPCO	Korea Electric Power Corporation
MOU	memorandum of understanding
NRC	U.S. Nuclear Regulatory Commission
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSERDA	New York State Energy Research and Development Authority
OCC	overnight capital cost
OECD	Organization for Economic Co-operation and Development
ORES	Office of Renewable Energy Siting (New York)
PJM	PJM Interconnection (mid-Atlantic regional grid operator)
PRDC	provision for revenue during construction (Options Paper grant variant)
PSC	New York Public Service Commission
RFP	request for proposals
RGGI	Regional Greenhouse Gas Initiative
SMR	small modular reactor
TCIC	total capital investment cost (as-built cost)
TEPCO	Tokyo Electric Power Company Holdings
UAE	United Arab Emirates

Units:

- kW / MW / GW / TW = kilowatt / megawatt / gigawatt / terawatt (capacity)
- A trailing "e" (kW_e, MW_e) denotes electric capacity
- MWh / TWh = megawatt-hour / terawatt-hour (energy)
- $/kW and $/MWh = cost per unit of capacity and of energy delivered

REPOWER NEW YORK: THE CASE FOR REPOWERING FOSSIL AND INDUSTRIAL SITES FOR RELIABLE, AFFORDABLE, CLEAN POWER

1 EXECUTIVE SUMMARY

New York's energy demand is rising for the first time in a generation, and the state's statutory emissions targets have slipped. The state needs firm (available on demand) clean energy fast and for cases beyond electricity. Roughly four-fifths of final energy demand lies outside the power sector, in process heat, fuels, and industrial loads.[1] Meanwhile, the June 2026 commitment to 5 GW of new nuclear under the 8.4 GW Nuclear Reliability Backbone requires New York to move faster than any nuclear program in the West has moved in fifty years.

New York can meet both electricity and industrial energy demand at the scale, cost, and speed it requires, while simultaneously decarbonizing and expanding its industrial economy. This paper sets out the evidence, data, tools, and a roadmap for doing so. Most of what New York needs is already in the state's own record. What this paper adds is a new way to apply that evidence to repowering fossil and industrial sites with advanced nuclear—replacing their existing boilers with nuclear heat while retaining the site, grid connection, and workforce—plus two tools that compress the early stages where project-level risks are highest and capital is priciest. Terra Praxis developed both tools and licenses their use; the policy recommendations in this paper are independent of both.

Decisions requested

This paper asks five decisions of five New York actors. Each is developed in the sections cited and sequenced in the roadmap in Section 9.

Governor's office: Direct procurement as a repeat-build program per the Options Paper's Option 3: an initial tranche of a proven design built as standardized onsite construction, with the later tranches held open for shipyard and factory delivery as each proves itself. Direct that pre-development stay reactor technology neutral until site evidence is in. Deadline: before Advanced Nuclear Master Plan finalization in 2026. (Sections 4 & 7).

Public Service Commission (PSC) and New York Independent System Operator (NYISO): Order retiring fossil plant owners to keep switchyards, transformers, cooling-water rights, and capacity interconnection rights in service-ready condition for a defined period, and hold that interconnection capacity in the queue, until the site has been screened for repowering. Deadline: before the next generator retirement notice is filed. (Section 5).

New York State Energy Research and Development Authority (NYSERDA): Fund fleet-wide screening of every retired and operating fossil site in the state and a site dossier for each volunteer host community, so the Master Plan and the matchmaking process start from site evidence. Cost: to be sized against the Options Paper's $160 million pre-Final Investment Decision (FID) grant, which the Paper finds lowers total public support by more than $600 million. Deadline: outputs in hand before the Master Plan is finalized. (Section 6).

New York Power Authority (NYPA): Build informed-buyer capability before FID, irrespective of who owns and finances the plant: an in-house should-cost estimate to negotiate against, the technical capacity to specify and evaluate a fully defined scope, a requirement that one accountable delivery organization on the developer side hold project management, engineering, licensing, and commissioning, and incentive alignment written into the contract architecture. Deadline: in place before the anchor project's request for proposals. (Section 7).

NYSERDA and the PSC: Make each state support instrument (Advanced Nuclear Zero Emission Credits / ANZECs, the cost-overrun guarantee, State equity, and pre-FID grants) contingent on the delivery practices the Options Paper endorses; set a quantified cost-reduction target for later units with named action owners; and adopt a construction-period cost-recovery mechanism with explicit ratepayer protection against overruns. Deadline: with the Commission's decision on the guarantee and ANZEC options. (Section 7).

The delivery model, more than the reactor, determines whether new nuclear arrives on New York's timeline and at an acceptable price. Where nuclear has been built as a one-off project on an incomplete design — Vogtle 3 and 4, Olkiluoto 3, Flamanville 3 — completion ran, 5–13 years late, and costs reached roughly two to four times the original estimate. Where it has been delivered as a programmatic, repeat build of a completed and standardized design, drawing on the industrial capacity and management practices of complex high-performance manufacturing, schedule and cost have held. Even a first-of-a-kind (FOAK) can hold: Japan's first two ABWRs at Kashiwazaki-Kariwa went from first concrete to commercial operation in four years, due to extensive front-loaded FOAK engineering and construction planning before ground-breaking (case study, Section 7). Those practices are documented and transferable: design completion before construction, serial manufacture of major components, an experienced supply chain, and contracts that hold delivery accountable. Applied to nuclear they de-risk delivery, attract private investment at lower cost, and enable fleet-scale development. New York can specify them in how it buys, and stage the Backbone's tranches up the delivery-model ladder: standardized repeat builds first, shipyard and factory delivery admitted as each proves out.

The state's own analysis shows that conventional nuclear in New York is expensive mainly because of financing and risk, not the cost of the reactor itself. The "Advanced Nuclear Policy Options Paper", published in June 2026 by NYSERDA, finds that even with federal tax credits and Department of Energy (DOE)-guaranteed debt, with private equity bearing the full construction risk, an initial greenfield-sited large reactor needs \$252/MWh, most of it financing carried over a twelve-year schedule.[2] The Options Paper largely treats that price as a financing and risk-allocation problem, to be solved with credits, guarantees, and equity, moving risk among ratepayers, the state, and investors without materially shrinking it.

Cost uncertainty can be reduced at its source, as was recently demonstrated. A Korean consortium built four APR-1400 reactors at the United Arab Emirates' Barakah site under a predominantly fixed-price contract signed in 2009.[3] The all-in capital cost, including interest during construction, came to \$5–6/W (2026 \$) across the four units, depending on the reported total—less than half the \$13.4/W modeled by the Options Paper for a five-reactor New York pipeline after accounting for full learning-curve effects.[4,5] Section 7 describes how the contracting process enforced the actions that reduced risk for both the buyer and the Engineering, Procurement, and Construction (EPC) vendor. Section 9 introduces how New York can apply these specific buyer practices.

New York's retired coal and fossil sites are the cheapest and fastest nuclear sites. Repowering sites retain the grid interconnections, cooling water rights, skilled workforces, and host communities that a greenfield nuclear project otherwise spends years and hundreds of millions of dollars assembling. The Options Paper finds that siting a large reactor at a brownfield site rather than on greenfield land lowers overnight capital cost, cuts the deployment schedule from twelve years to ten, and materially reduces public support. It values a 5 GW build at roughly \$50 billion in system-wide net benefits through 2050, against a public support cost of \$15–24 billion.[6] On an undiscounted basis, each gigawatt of new nuclear would generate \$15–20 billion in value over a 40-year operating life.[7] While the benefits could be much higher by maximizing brownfield advantages, options for repowering are perishable. Once power plant turbine halls are demolished and switchyards dismantled, a site reverts permanently to greenfield cost, schedule, and siting risk. **Recommendation:** New York should commit to repowering now; and act to preserve its retired fossil sites and their grid connections while it does so.

Repowering with advanced nuclear also reaches industrial demand that the grid cannot serve. A repowered site can produce heat as well as electricity, serving hydrogen production, district heating, and firm power to reshored manufacturing and data centers driving New York's load growth. Firm capacity also shrinks the energy system New York must build and maintain, both generation and transmission.

The delivery model is key. "A New Nuclear World", an independent LucidCatalyst study commissioned by Urenco with support from the World Nuclear Association, sizes the industrial market for nuclear across North America and Europe at \$0.5–1.5 trillion.[8] Despite this potential, only 7 GW is deployed by 2050 under the current one-off bespoke *project* deployment model. A standardized, repeat-build deployment *program* increases this to 120 GW. Evolving the deployment model to *mass manufactured reactors* could deploy nearly 700 GW. Custom-built projects with unpredictable costs and decade-long timelines cannot meet industrial requirements. Industrial buyers need fixed-price contracts, rapid deployment, guaranteed delivery schedules, and proven operational performance. That is also the definition of a commercially viable industry: a product that industrial buyers will purchase at a fixed price, on their own balance sheets, without needing credits, guarantees, or State equity. *New York's Backbone procurement is worth more than the 5 GW of new nuclear capacity, because how the State buys determines whether nuclear stays dependent on public support or becomes a product New York can sell.*

The REPOWER model offers speed and scale at a competitive price. The New Nuclear World study identifies six drivers that determine whether nuclear scales:

1. **Delivery innovation through product-based manufacturing**: from on-site construction into factories, using design-for-manufacturing-and-assembly principles.

2. **Site availability at scale**: from a handful to hundreds of pre-qualified sites able to serve local demand.
3. **Regulatory evolution through product-based licensing**: from lengthy site-by-site licensing (each nuclear plant a unique project) to product-based licensing (certifying standardized building products).
4. **Economic viability through policy support that values firm clean power**: from expensive projects requiring massive government support to affordable products that outcompete fossil-based alternatives.
5. **Capital access through mainstream financing**: from specialized nuclear financing and one-off megaprojects to predictable, repeatable products with reduced risk that attract private sector funding.
6. **Maturing developer ecosystem with a proven delivery track record**: from a few integrated utilities with a limited pool of projects to an industrial ecosystem of integrated supply chains, skilled workforces, and experienced project developers who align incentives, apply best project management practices, and capitalize on lessons learned from large order books, and leverage the latest digital tools.

New York has moved on all six—a pathway to demand pooling across ten states, eight communities who have volunteered to host nuclear plants, developer and technology pre-qualification, credits and guarantees under consideration, a return profile that steps down with repeat builds, and 23 developers responding to the state's solicitation. What is missing is site-specific evidence early enough to price. **Two tools make New York's timeline achievable.** Terra Praxis' REPOWER Automated Configuration Technology (ACT) platform, built with U.S. Department of State funding, advances a site from screening through suitability evaluation, automated layout design, construction scheduling, and industrial energy pathways.[9] It produces screening- and pre-feasibility-level outputs in weeks versus 12–18 months for a conventional site study. The Gen AI for Licensing copilot, developed with Microsoft, can cut the time required to prepare nuclear licensing applications by as much as 90%.[10,11] Both can run against New York's sites now. Time spent in predevelopment is the costliest time in a nuclear project. The Options Paper prices development-stage equity at 35–40% per annum, because until that work is done, the probability of success is unknown—and every month it takes, that rate compounds. Making site validation cheap, accurate, and early lowers the cost of capital for every following stage. Furthermore, consistent analysis across many sites enables prudent financial decision making by the state.

Recommendation: buy the Backbone as a *program* of repeat builds. Deployment as a program means the repeat build of multiple units of the same design. Building a large order book induces organizations to invest in technologies and systems that reduce overall costs. However, pre-development work should stay neutral on reactor technology, so the state commits to a design only once the evidence is in. The Options Paper already prices the payoff. Construction-stage equity hurdle rates (the minimum return investors require) fall from 35% to 17.5% by the fourth large-reactor unit (from 40% by the eighth for an SMR), and the largest learning rate in the state's model applies only to repeat units built at the same site (a first unit earns none of it, and factory-built designs capture most of the same saving by minimizing site work).

A repeat-build program is also industrial policy for New Yorkers. Most of a plant's cost is steel, concrete, piping, modules, and the skilled labor to fabricate and install them; the reactor itself is a minority share. How much of that spending stays in New York depends on policy. The Options Paper estimates that New York's currently nuclear-qualified suppliers could win only 15–16% of a reactor's overnight capital cost, including the labor that installs it, with the rest imported.[12] Other states are competing for that share. Pennsylvania's June 2026 nuclear energy roadmap, produced by Team Pennsylvania with an industry, labor, and university task force, sets out to capture the manufacturing, engineering, and lifecycle value of the national build-out. It directs suppliers toward "multi-state order books" so that in-state firms "scale alongside national deployment, even when reactors are built elsewhere," and targets recognition as a national hub for those services by 2040. It lists New York's 5 GW ambition among the demand it intends to serve, and names forging as a particular strength.[13] The 15–16% is therefore a starting position in a competition: a neighboring state has published a strategy to win the remaining scope. Worse, generation built in another state and delivered over a wire captures none of it while adding to the half of New York's energy spend that already leaves the state.[14] Buying a delivery model expands both New York's share and its industrial base: an order book of identical units gives New York fabricators, module shops, and building trades a demand signal firm enough to justify tooling, apprenticeships, and plant investment, and keeps repowered fossil sites operating as employers.

New York is poised to deliver clean energy abundance at the necessary speed, scale, and cost with a REPOWER strategy. The state is choosing among three paths, and only one gets cheaper as it scales. Adding ever more renewables to a grid that is costly to decarbonize grows more expensive over time. Treating new nuclear as a sequence of one-off, bespoke projects lowers system-level costs and improves reliability, but at a higher cost than fossil combustion. **Only a standardized, repeat-build program drives costs down through learning while unlocking markets a renewables-heavy strategy cannot reach.**

2 NEW YORK'S ENERGY CROSSROADS: THE SCALE OF THE CHALLENGE

The stakes for New York are fiscal, statutory, and industrial.

Fiscally, New York's total energy expenditure reached $80 billion in 2022, the highest in fifteen years, before easing to $74 billion in 2023.[15] New York has also set some of the most ambitious decarbonization targets in the U.S. The state's *Climate Leadership and Community Protection Act* (CLCPA, 2019) set a statutory requirement of 70% renewable electricity by 2030, a zero-emission electricity system by 2040, and 9,000 MW of offshore wind by 2035. But seven years in, the state's Department of Public Service (DPS) has indicated the 70%-by-2030 target may not be met until 2033, or 2035 in a high-load-growth scenario.[16] A July 2024 letter signed by more than 60 organizations, including the Business Council of New York State, four International Brotherhood of Electrical Workers (IBEW) locals, the New York Farm Bureau, and dozens of regional chambers of commerce, described the pathway to a 40% economy-wide emissions cut by 2030 as "not achievable even with full implementation" of current strategies.[17]

The grid operator, NYISO, confirms that electricity demand is set to increase materially over the next two decades, reversing years of flat or declining load.[18] Electrification drives part of that increase; the rest comes from large new loads, principally the manufacturing facilities and data centers that NYISO now projects could add up to 5 GW over the outlook period. The same demand pressure shows up nationally. Of the roughly 8.5 GW of coal retirements originally planned for 2025, only about 2.6 GW occurred, the least in fifteen years. Federal emergency orders and separate utility decisions kept the rest running, because grid operators didn't have enough firm capacity to replace them.[19]

New York therefore faces three pressures at once: a legal and political commitment to rapid decarbonization and binding near-term targets slipping under cost and reliability pressure, while facing rising demand from exactly the industries the state's economic development strategy is trying to attract.

3 THE TRANSMISSION AND INTERMITTENCY TRAP

A strategy built largely on intermittent renewables cannot deliver

The immediate constraint is the grid—and electricity is only part of what New York needs to decarbonize. New York State's 2025 Energy Plan is candid about the physical limits of a renewables-heavy grid: *"Clean firm resources are able to reliably and flexibly provide energy and capacity to the grid (especially when intermittent sources such as wind and solar are unavailable) and provide support services like voltage regulation."*[20] That sentence, in the state's own planning document, means that intermittent generation alone cannot satisfy the reliability standard New York's grid operator requires. A grid built overwhelmingly on intermittent generation needs something to fill the gaps when wind and solar fall short, and whatever fills them—transmission, storage, or natural gas—grows more expensive as the renewable build-out expands, because each additional increment of wind and solar contributes less firm capacity and so requires more backup, more storage, or more transmission to be usable.[21]

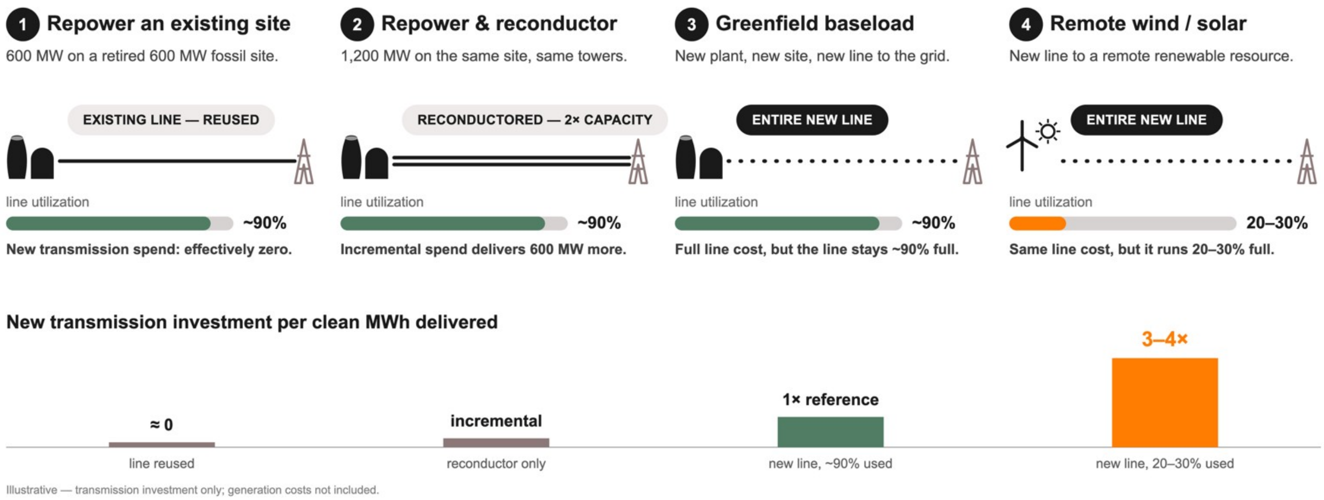
The costs of bridging that intermittency are visible in the state's numbers, and they run in one direction. Every decarbonization scenario modeled for the 2025 Energy Plan costs more than doing nothing through 2040 on energy-system cost, although the Plan finds net societal benefits once health and climate benefits are counted. The cost rises with the share of intermittent generation, because the system must be built twice: once for the wind and solar capacity, and again for the firm capacity, storage, and transmission that make it dependable.

That cost pressure is already visible at the contract level. Offshore wind, once central to the CLCPA's plan, re-priced sharply: Empire Wind 1 and Sunrise Wind were finalized in June 2024 at a weighted-average price of $150/MWh, over 3× the wholesale electricity price in Long Island.[22,23] These contracts are in line with current market prices, but they are a marked increase on the assumptions used when New York originally set its offshore wind targets. Statewide, nearly 1.4 million customers were more than 60 days behind on utility bills at the end of 2024, owing a combined $1.9 billion[24], a measure of the affordability pressure any new energy spending must be weighed against.

The underlying reason transmission costs so much more for a renewables-heavy grid is structural and applies in every jurisdiction (see Figure 1). Because wind and solar operate at lower capacity factors than firm generation, moving a given amount of energy to load requires substantially more transmission capacity per unit of energy delivered. Both repowering options are cheaper and faster. Reusing a retired site's existing interconnection carries no new transmission cost. Reconductoring a transmission line to double its capacity adds only incremental spending. A brand-new line to either a greenfield baseload site or a remote renewable resource costs substantially more, and the timeframe to establish a new right of way is measured in years, if it is possible at all.

Wind requires roughly twice as much transmission per unit of generation as firm generation, and grid-scale solar roughly four times as much, according to Terra Praxis' 2023 cross-country analysis "Risks to the Energy Transition".[25] This gap is what drives transmission spending up as renewables scale. Better siting or faster permitting cannot remove it, because it is a property of the energy resource.

Figure 1: The transmission arithmetic: four ways to add clean energy to the grid



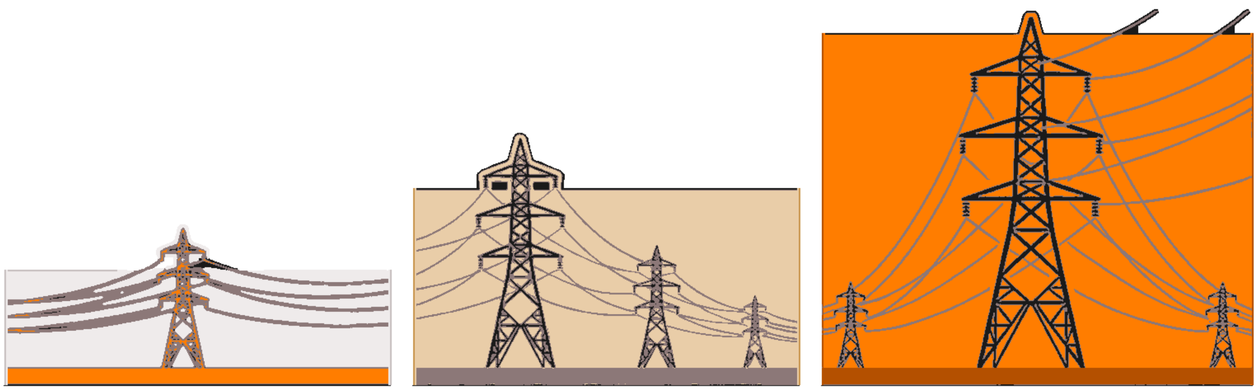
Firm clean capacity is the resource that closes these gaps, and New York's own institutions have said as much. The Manufacturers Association of Central New York (MACNY), representing advanced manufacturers across the region, has called for a "*balanced energy portfolio that includes high-capacity-factor resources such as nuclear power*," arguing that "*continued investment in advanced nuclear technologies positions New York at the forefront of both energy innovation and industrial growth*."[26] New York's business and labor coalition made this point in July 2024: *"New York's business community is facing additional uncertainties under the CLCPA, including its impact on the cost, availability and reliability of electric power delivered through a grid increasingly reliant on intermittent solar and wind generation."*[27]

New York's regulators have already defined the category of resource the grid is missing. Sharing this concern, the PSC ordered a technical assessment to identify technologies able to "close the gap between the capabilities of existing renewable energy technologies and future system reliability needs." The resulting "Zero by 40 Technoeconomic Assessment" ("Zero by 40"), prepared for NYSERDA in 2025 by the Electric Power Research Institute (EPRI), defines the category directly: *"Dispatchable emissions-free resources are defined as resources that produce zero emissions during operation, can be called on (dispatched) to provide energy and capacity when needed, and can operate reliably during extreme events and extended periods of low renewable generation."*[28]

Advanced nuclear is one of seven such technologies evaluated, alongside hydrogen, biofuels, carbon capture, next-generation geothermal, long-duration storage, and virtual power plants. Zero by 40 recommends that the state "pursue a diverse set of resources to minimize the risk of overreliance on individual technologies," and concludes that the dispatchable firm resources it studied "will play a critical and complementary role in supplying clean, firm power during extended periods of high demand and low renewable generation."[29]

New York's own transmission planning has identified nuclear energy as a key, cost-effective way to meet future demand. The "Coordinated Grid Planning Process" (CGPP), the state's long-term transmission and distribution planning initiative, reached that conclusion directly.[30] In its Cycle 1 modeling, just 5.5 GW of nuclear-like firm capacity by 2042 shrinks the total system needed to serve the same load by 30 GW—100 GW versus 130 GW—and cuts new local-transmission headroom by a quarter (9 GW versus 12 GW). That comparison likely understates the benefit of a repowering-led strategy. Repowered sites use transmission that already exists, at a high capacity factor. Where capacity must be added it goes along an existing corridor: advanced conductors, already demonstrated in multiple utility projects, can raise the rating of an existing line by two to three times without changing supports or setbacks.[31] These well-established costs come with low financial risk. A repowering strategy therefore needs less new transmission per unit of clean energy delivered than any other pathway to the same firm capacity.

Figure 2: Across all three pathways studied by Princeton Net-Zero, transmission buildout scales inversely with how much new firm capacity is added



Nuclear/Carbon Capture Focus
(Scenario E+ RE-)
306 TW-km needed. **Doubles the 2020** grid to support constrained renewables.

Standard Electrification
(Scenario E+)
673 TW-km needed. **More than triples (3.1)** the 2020 grid to accommodate renewables.

All-Renewables Focus
(Scenario E+ RE+)
1,309 TW-km needed. **Over five-times (5.1)** the 2020 transmission grid needed to keep the lights on.

Nationally, the more firm capacity a net-zero pathway includes, the less transmission it needs. Princeton University's "Net-Zero America" study puts numbers on that trade-off (Figure 2).[32] Modeling distinct pathways to net-zero emissions by 2050, the study finds that a scenario combining a historical renewable build-out rate with rapid nuclear expansion ("E+ RE-": 260 GW of new advanced nuclear by 2050) requires transmission capacity (measured in GW-kilometers: capacity multiplied by line distance, not route-miles) to roughly double relative to 2020. A scenario reaching net-zero on 100% renewables and no nuclear ("E+ RE+": 5.9 TW of wind and solar, nuclear phaseout) requires 5.1 times the 2020 transmission capacity. The unconstrained base case ("E+"), which retains most of the existing fleet while adding only modest new nuclear capacity, still requires transmission to more than triple.

New transmission cannot be built at the pace a renewables-heavy plan requires, and that delivery limit binds before cost does. Transmission is also costly: it is paid for either through NYPA's own self-financed capital program or through utility rate cases—New York's own Cost Sharing and Recovery Agreement for the CGPP portfolio is the latter mechanism in practice.[33] The two differ mainly in governance and cost of capital; customers ultimately pay under both. The tighter constraint is delivery. New high-voltage transmission construction has collapsed nationwide even as the need has grown: annual build-out of new 345 kV-and-above transmission fell from an average of 1,781 miles a year in 2010–2014 to 536 miles a year in 2020–2024, even as utility transmission capital budgets climbed to $35.9 billion in 2024 and $37.6 billion in 2025.[34] The Department of Energy's own "National Transmission Needs Study" puts the 2035 requirement at 64% above today's system.[35] A plan that depends on transmission being built faster than the country has managed in over a decade carries a delivery risk that no cost estimate captures. Slow transmission only slows projects that need new transmission, so a project that reuses existing capacity and interconnection rights, such as a repowering project, largely avoids the problem.

What Ontario's experience offers New York

Ontario met the cost and siting pressures of a renewables-led build-out a decade before New York, and its *Green Energy Act* followed an arc New York should recognize: an ambitious mandate, a subsidized procurement build-out, a cost-and-siting backlash, a legal reckoning, and a retreat. The parallels, set out in Table 1, are close enough to serve as a warning, and as an argument for a decarbonization pathway that is fiscally and politically sustainable.

Ontario's *Green Energy Act* combined three features New York later adopted: guaranteed-price contracts, domestic-content rules, and centralized siting authority. Ontario passed the Act by a vote of 59 to 13 on May 14, 2009. It launched 20-year guaranteed-price contracts, with initial small-solar ("microFIT") rates as high as $820/MWh (2026 $) and phased in domestic-content requirements that escalated to 50% for wind and 60% for solar by 2011–2012.[36,37] The Act also centralized renewable energy siting approval at the provincial level, superseding municipal zoning authority. That structure stood until the Act's 2019 repeal restored municipal planning authority under a "willing host" model.[38] New York's equivalent, the Office of Renewable Energy Siting (ORES), created under "94-c" in 2020 and empowered to override local law for renewable projects above 25 MW, followed roughly eleven years after Ontario's regulation.[39]

Ontario's move to strip local siting authority reflects a pattern documented well beyond the province. Terra Praxis' Risks to the Energy Transition found that opposition to wind projects in Iowa became more frequent and better organized between 2008 and 2023 as more projects were built.[40] Local acceptance declined as deployment grew. That is why centralized siting authority tends to emerge as a response to growing local resistance, in Iowa as in New York's ORES and 94-c regime.

Table 1: New York has not repealed the CLCPA. But several of its own recent milestones sit on a comparable timeline to Ontario's, a decade or so behind

Theme	Ontario	New York	Lag
Passage	Green Energy Act passes 59 to 13, made into law the same day (May 2009)	CLCPA passes Senate 41 to 21 (June 2019); signed into law by Governor Cuomo, with Al Gore in attendance (July 2019)	~10 yrs
Siting authority	Reg. 359/09 centralizes siting, overrides municipalities (2009)	ORES/"94-c" centralizes siting, overrides local law ≥25 MW (2020)	~11 yrs
Legal reckoning	World Trade Organization Appellate Body rules against domestic-content rules following complaints from Japan and the EU (May 2013)	Court rules state violating its own statutory climate deadlines (October 2025)	~12 yrs
Cost backlash	Auditor General finds ~C$37B paid above market price over 8 years (2015)	Business, labor, and energy coalition demands cost transparency (2024)	~9 yrs
Retreat	758 contracts cancelled; Green Energy Act repealed outright (2018–19)	Binding 2030 target rolled back to a non-binding 2040 goal (2026)	~7 yrs

Ontario's cost backlash was quantified by the province's own auditor and ended in repeal. Ontario's Auditor General reported in December 2015 that ratepayers had paid approximately C$37 billion above market price for electricity over the preceding eight years, with another C$133 billion in additional costs projected by 2032.[41] That $37 billion overpayment was equivalent to roughly 26% of everything Ontarians paid for electricity, across all charges, over the same period.[42] Press coverage of the report attributed those costs to "haphazard planning and political meddling."[43] In July 2018, Ontario's newly elected government cancelled 758 renewable energy contracts[44], and the *Green Energy Repeal Act* took effect on January 1, 2019, formally ending the province's *Green Energy Act* regime.

New York's own legal reckoning arrived in October 2025, when a court held the state in violation of its own statutory climate deadlines: the CLCPA had required New York State Department of Environmental Conservation (DEC) to promulgate economy-wide emissions-limit regulations by January 1, 2024, and DEC conceded that it had not. New York has since moved that statutory deadline to December 31, 2028—closing the violation by moving the deadline nearly five years while the regulations remain unissued.[45]

The comparison with New York should not be overstated. Ontario repealed its law outright, while New York has softened its targets and kept them in place. This discussion paper argues for a course correction within New York's decarbonization commitment. Storage and efficiency also pair with nuclear. The same utilities that operated America's largest nuclear fleets built most of its major pumped-storage plants to balance that baseload—Dominion's 3.0 GW Bath County (paired with Surry and North Anna), TVA's 1.7 GW Raccoon Mountain

(Browns Ferry, Sequoyah, Watts Bar), Duke's 1.8 GW Bad Creek–Jocassee pair (Oconee, McGuire, Catawba), and Consumers/DTE's 1.9 GW Ludington (Palisades)—more than 8 GW of storage built specifically to pair with nuclear and coal, for the same load-balancing reason it pairs with renewables today.[46] **Recommendation:** continue investing in efficiency and storage alongside the Backbone; both keep paying off alongside nuclear as they do alongside renewables.

Ontario's history also offers a counter example: the province achieved the first coal phase-out in North America. This effort, 2003–2014, succeeded primarily because Ontario restarted and refurbished its nuclear fleet, lifting nuclear's share of generation from about 42% to 60%, with new gas capacity supplying much of the remaining firm backup; and the Green Energy Act's variable-renewables build-out contributed far less.[47] The U.S. Department of Energy's (DOE's) "Pathways to Commercial Liftoff: Advanced Nuclear" analysis draws a similar conclusion for the United States. Its system modeling shows that "while renewables will play an essential role, decarbonizing the grid will be very difficult and expensive without 20–40% clean firm power," and the report projects that advanced nuclear alone could add roughly 200 GW of new U.S. capacity by 2050 if deployment begins by 2030.[48]

New York's pivot toward the Nuclear Reliability Backbone keeps the CLCPA's ambition and applies what Ontario's history shows: anchor a decarbonizing grid on firm clean power and let wind and solar grow on a reliable foundation. Repowering coal and fossil sites with advanced nuclear gives the state an anchor, as well as a reliable partner for existing and planned renewable investments. NYSERDA's Options Paper shows roughly $50 billion in system-wide net benefits through 2050 from a 5 GW nuclear buildout, measured against the cost of providing that same firm, reliable capacity through additional transmission, storage, and renewables overbuild.[49] Set against a public support cost of $15–24 billion under its base-case greenfield pipeline, these benefits are substantial.

The Backbone has a defined shape. It combines 5 GW of new nuclear generation—including a directive to the NYPA for at least 1 GW upstate—with New York's existing 3.4 GW of nuclear capacity. Eight upstate communities have volunteered to host new nuclear capacity, ahead of a full "Advanced Nuclear Master Plan" targeted for the end of 2026. **The fastest, lowest-cost, and highest-value way to deliver that Backbone, and go well beyond it, is to repower New York's retired and at-risk fossil and industrial sites with advanced nuclear energy**.

4 ENERGY SINKS TO SOURCES: THE REPOWERING OPPORTUNITY FOR NEW YORK

New York's retired fossil sites are the fastest and cheapest places to add firm clean capacity, and that capacity has value beyond the grid: industrial heat, hydrogen, and synthetic fuels, which nuclear can serve directly and renewables cannot serve at competitive cost.

Repowering turns energy sinks into energy sources: fossil plants and industrial facilities that consume fuel and emit carbon become firm, clean generators by hosting advanced nuclear reactors on the same sites. Risks to the Energy Transition recommended that policymakers "repurpose assets" and "leverage as much of the existing infrastructure as possible," on the grounds that advanced heat sources sited at existing fossil and industrial facilities require "far less incremental transmission, land use, and inter-state connectivity" than new greenfield renewable capacity.

New York has the sites. The state's last operating coal plant (Somerset) closed in 2020. The 2.3 GW Indian Point nuclear station was prematurely shuttered in 2020–2021, a key driver of the downstate firm capacity shortfall today and why every remaining downstate interconnection matters. Its former coal and fossil sites retain grid interconnections, cooling water rights, a transferable industrial skill base, and host communities built around industrial energy infrastructure—assets that are idle at the moment New York is searching for nuclear sites. And the candidate pool is still growing: the state's grid operator reports that New York's generation fleet is among the oldest in the country, with a significant share of the fossil fleet now more than 50 years old while producing roughly 10% of in-state electricity in 2025.[50] Many units that provide essential reliability services are nearing retirement and power producers are already weighing conventional repowering of some 3,500 MW of aging fossil generators in New York City and on Long Island. **Recommendation:** put every retired and retiring fossil site on the Advanced Nuclear Master Plan's screening list before any owner takes further decommissioning steps.

The case for repowering

The capacity-factor case. A retired fossil plant's grid interconnection is permitted and sized for continuous, dispatchable power: a better starting point for a technology that runs at high, steady capacity factor than for a technology whose output varies with weather. Terra Praxis' analysis of a thirteen-site, 24 GW coal fleet operating at just 10–17% capacity factor found that repowering it to 95% capacity factor would increase the host country's entire electricity generation by over 170%.[51]

The site-agnostic case. Advanced nuclear needs only water access, grid interconnection, and a willing host community; wind and solar economics depend on local wind speed, solar irradiance, and open land. New York's industrial and aging fossil sites already have all three. The siting arithmetic is the practical form of that advantage: 5 GW of nuclear means finding two or three workable sites of a few hundred acres each, the footprint New York's retired fossil plants already occupy, while the same annual electricity from solar would mean on the order of 30 GW of panels across roughly 200,000 acres, plus storage acreage to make that output dispatchable.[52] As "New Directions in Nuclear Energy" puts it, "deployable without geographical limitations, nuclear technology can help secure industrial sector jobs, reduce carbon emissions, and decrease local pollution."[53]

The carbon case. Firm nuclear capacity sited at a retired fossil plant can displace natural gas plants otherwise needed to fill in when output from variable renewables drops: precisely the gap New York's 2025 Energy Plan says requires "clean firm resources" to close.

The deep decarbonization case—electricity plus industry. Repowering can also decarbonize industrial heat, which a clean grid alone cannot reach, and this may be New York's largest opportunity. Today, industrial process heat is supplied overwhelmingly by burning fossil fuels on site, and those emissions cannot be abated by cleaning up the grid. Converting retired fossil sites to advanced nuclear lets them supply electricity and also process heat for industrial manufacturing, hydrogen, and district heating.[54,55] These end uses share one requirement: continuous, high-temperature, firm thermal energy—which a nuclear heat source provides and wind and solar cannot.

The investment opportunity case. The New Nuclear World study sizes the industrial small modular reactor (SMR) opportunity across North America and Europe at $0.5–1.5 trillion of investment. Synthetic fuels for aviation and maritime transport, coal repowering, data centers, and chemicals together represent more than 75% of that total. Food and beverage, iron and steel, and district energy are significant additional sub-sectors. The innovations in manufacturing, licensing, and siting that the study identifies as critical for *scale are already emerging in the market.* On the grid, firm nuclear makes decarbonizing cheaper. Beyond the grid, it is the only practical route for a large fraction of final energy demand in process heat, fuels, and industrial loads that electrification cannot reach.[56]

New York's demand growth is concentrated in these same categories: semiconductor manufacturing plants, data centers, green hydrogen production plants, and rising electric vehicle adoption. A repowered brownfield site, sized and sited correctly, could supply firm power directly to a co-located data center campus, process heat to an adjacent industrial user, hot water to a district heating network serving the host community, and firm power to the grid. That is four revenue streams from a single site and a single interconnection.

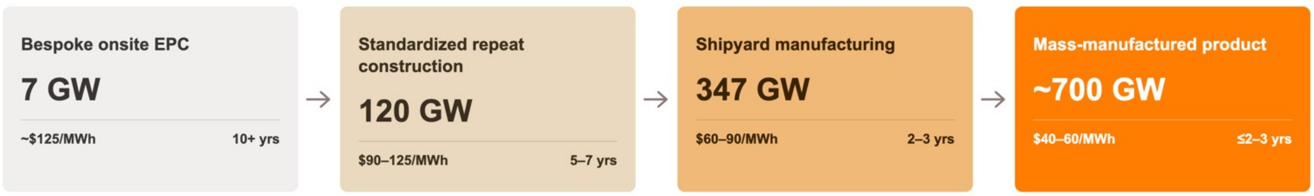
The community and workforce case. Many host communities of retired fossil sites and brownfield industrial sites depended on these plants for local tax base and skilled employment. Repowering could preserve or revitalize that economic base; demolition followed by greenfield renewable development elsewhere would end it. The workforce transfers: 77% of coal-plant positions are transferable to a nuclear plant with no new licensing requirements[57], and in a DOE case study replacing a composite 1,200 MW_e coal plant with 924 MW_e of nuclear capacity, regional economic activity increased by as much as $275 million, including the surrounding community gaining more than 650 net permanent jobs.[58]

Buy the delivery model as well as the Backbone

How New York buys the Backbone matters as much as what it buys. The New Nuclear World study finds that while demand is ample, the delivery model limits nuclear's share of the industrial market. So the procurement matters beyond the power it adds to the grid: a Backbone bought as a repeat-build program can help shift the whole industry onto the delivery model that determines the market size. Under the current bespoke, engineer-to-order construction model, only a small fraction of the potential market would be served by 2050. It fails the business requirements of industrial energy buyers on every count: unpredictable costs, cost-plus contracts, decade-long timelines, and licensing risk carried by the customer. Section 7 shows that financing carry, meaning the financing costs that accumulate while capital is tied up in construction, is what makes a conventionally built, fully privately financed unit uneconomic; the reactor's own cost is a secondary factor. Industrial energy buyers need low upfront capital, fixed prices, deployment inside two-to-three-year industrial planning cycles, and, in many cases, energy-as-a-service structures that require no operational involvement.

As seen in Figure 3 the study's ladder has four rungs: Bespoke onsite EPC, each plant engineered and licensed as a one-off, built in the field over ten-plus years (serving 7 GW of industrial demand in North America and Europe by 2050). Standardized onsite construction, the same field work repeated across a firm order book, five to seven years a unit (reaching 120 GW). Shipyard manufacturing, modules fabricated in the heavy industrial facilities already proven for naval construction and assembled on site, two to three years (achieving 347 GW). Mass manufacturing, reactors produced on factory production lines and shipped for onsite assembly, two to three years or less (capturing about 700 GW). New York can buy the second rung with the Backbone as it stands; the rest require an order book large enough to justify the factories behind them.

Figure 3: Nuclear delivery model sets the industrial market size in North America and Europe: from about 7 GW by 2050 under the current bespoke delivery model to nearly 700 GW at full industrialization



The Backbone can be staged up this ladder. The study is explicit that its four rungs are parallel pathways rather than a fixed sequence.[59] The procurement should therefore state the evidence that admits each rung, rather than leave it to a later technology choice. Three tranches follow.

First tranche: standardized onsite construction. A firm order for repeat units of one completed, licensed design at the fewest viable sites. It is what the Backbone can buy today, and its job is to start the workforce and supply-chain learning that Section 7 prices, and to build the program office and should-cost data an informed buyer needs.

Second tranche: shipyard manufacturing. At the study's $60–90/MWh, admission turns on evidence rather than a date: a shipyard-built reference unit operating or under construction on a fixed-price contract, a design licensed for that manufacturing route, and a New York order book worth a production slot. The shipyard-style prefabrication now being financed in Texas (Section 7) is the first test.

Third tranche: factory manufacturing. The study prices it at $40–70/MWh and ties it to product-based licensing and to designs engineered for manufacture from the outset. New York cannot build that rung alone; its order book, added to the industrial demand already announced across North America and Europe, is part of what justifies the factories. Admission requires a certified product with a licensed factory behind it.

The gates between tranches are delivery-model tests, not technology preferences. A large light-water reactor, an SMR or a microreactor qualifies for a later tranche by meeting the delivery conditions of that rung. The State's design-agnostic pre-development (Section 6) and Early Site Permits (Section 7) keep every class eligible until the evidence is in; Option 3's decision points (Section 7) are where the test is applied.

The customers already exist. Of the roughly 40 GW of SMR projects announced across North America and Europe as of 2025, about 80% are driven by non-traditional customers: data-center operators, chemical producers, and industrial hosts, with the remainder largely from utilities.[60]

Advancing up the delivery-model ladder, the study argues, depends on progress across six market drivers: product-based manufacturing, pre-qualified sites, product-based licensing, policy support that values firm clean power, mainstream financing, and a mature developer ecosystem. Table 2 sets out where New York stands on each driver. The sections that follow give greater detail on the State's progress with each driver, the evidence and digital tools Terra Praxis brings (REPOWER ACT and Gen AI for Licensing), and the value and next steps for New York.

Table 2: The six market drivers: New York's progress, and the evidence Terra Praxis brings to each

#	Market driver	New York's progress, proceedings & support	What Terra Praxis demonstrates	How this benefits New York's program
1	**Delivery innovation** Product-based manufacturing	Backbone procured as a multi-unit order book; demand pooled across ten states.	REPOWER ACT configures a buildable plant layout from standardized components in weeks; the reactor design stays with the vendor.	Lets NYPA rank many options using a consistent approach and sequence construction across sites before committing to any one vendor's build timeline.
2	**Site availability** Hundreds of pre-qualified sites	Eight volunteer host communities; published siting criteria	ACT screened a thirteen-site, 24 GW coal fleet end-to-end in December 2025—suitability, layout, cost, and schedule per site.	Every volunteer community gets a site dossier and a development plan before matchmaking, in addition to its expression of interest.
3	**Regulatory evolution** Product-based licensing	Pre-qualification of developers and technologies; accept a proven design without bespoke re-review.	Gen AI for Licensing: up to 90% fewer human-hours to prepare a licensing or permitting application.	Compresses state siting and transmission permitting enough to fit the Options Paper's roughly one-year matchmaking schedule.
4	**Economic viability** Policy support valuing firm clean power	25-year clean-energy credits, a cost-overrun guarantee, State equity, and early-development grants under consideration.	Terra Praxis' 2023 cross-country analysis, Risks to the Energy Transition, quantifies the value of firm power: wind needs roughly 2× the transmission per unit of energy that firm generation does, and grid-scale solar needs roughly 4× as much.	Gives the PSC a New York-specific number to weigh against the cost of the credit and guarantee instruments under consideration.
5	**Capital access** Mainstream financing	Investor return requirements step down from 35% to 17.5% through guarantees and repeat builds.	In December 2025, ACT demonstrated an itemized capital-cost breakdown and construction schedule alongside a suitability score.	Gives NYPA a should-cost benchmark, so bids are tested against the state's evidence.
6	**Developer ecosystem maturation** Proven delivery track record	23 developers responding to the state solicitation; partnership with Ontario Power Generation.	ACT's generative-design engine is built to configure a layout for whichever design is under consideration, not one vendor's proprietary product—the same platform and site data serve any developer or design class equally.	Keeps competition open among vendors and technologies through pre-development, so a design is chosen only once the evidence is in.

Recommendation: New York should move first on two of the six drivers. First, pre-qualify sites by screening the state's retired and at-risk fossil sites and industrial facilities. Second, procure the Backbone in a way that drives the market towards commercial liftoff and away from dependence on out-of-market support.

5 SITES: THE NEXT DRIVER, AND A CLOSING WINDOW

The same-site learning path

Build several units at a few sites. The Options Paper's own cost model gives the largest learning benefit only to repeat units at the same site: of the five cost components subject to "learning" as more units are built, the largest, a 30% maximum learning rate on owner's costs, applies only to repeat units built at the *same site*. Materials and labor learning transfers only within a region; only equipment and indirect-cost learning transfers nationally. Two qualifications follow. A FOAK unit built on the Options Paper's assumptions should be credited with little or no learning at all; the benefit accrues only once repeat units follow. And this mechanism is only modestly relevant to manufactured delivery: shipyard-built or mass-manufactured units reach low costs largely by eliminating the complicated site work in the first place, so most of the savings this mechanism describes are already built into their cost base. **Recommendation:** plan the Backbone around multiple units at the fewest viable sites, so that the same-site learning rate applies.

Figure 4: New York's fossil, industrial, and nuclear sites; transmission network at 115 kV and above

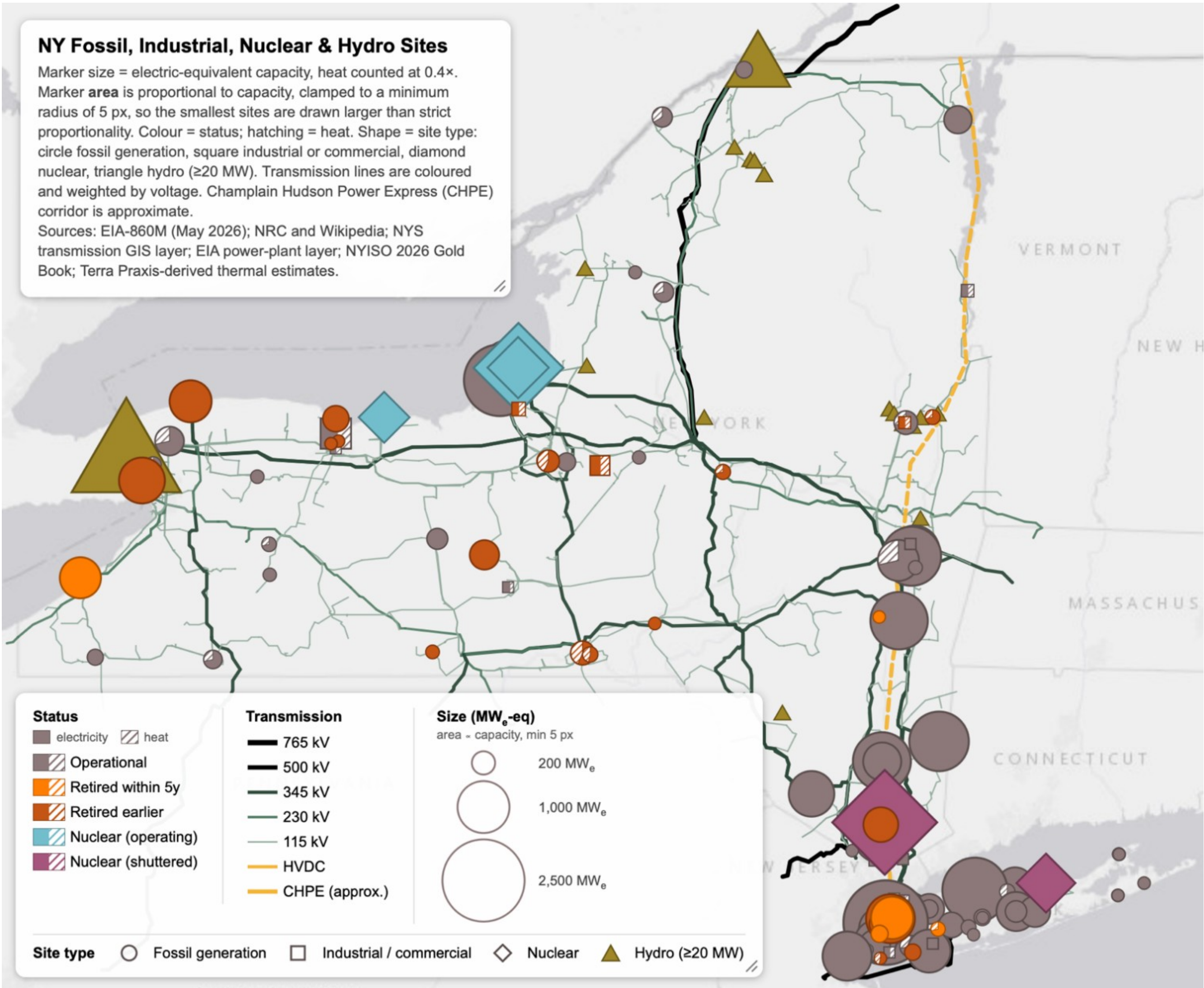


Figure 4 maps New York's fossil, industrial, and nuclear sites, retired and operating; together they are enough candidate sites to fill a repeat-build order book. **Recommendation:** qualify these sites for new nuclear quickly; a qualified site inventory is what makes a firm multi-unit order book credible to vendors and financiers. Screening every site and building at few are compatible: the screen is how the state finds the few, and it also identifies the industrial-heat offtakers that make a particular site worth more than its grid connection.

The urgency for action

A retired plant's interconnection can be lost within a year of shutdown, and getting it back costs years and hundreds of millions of dollars. The single most valuable asset at a retired power plant is its grid interconnection, and that asset can be lost even while the physical wires and switchyard remain standing, because interconnection is a legal right as much as a physical one. Three Mile Island Unit 1, which Constellation Energy is restarting as the Crane Clean Energy Center under a 20-year, full-output power purchase agreement with Microsoft signed in September 2024, shows how. At its 2019 retirement, plant staff drained and scrapped the unit's main power transformers, because no one expected the reactor to run again. Constellation has since had to replace that equipment at a cost of roughly $100 million.[61]

Interconnection rights lapse quickly after retirement. PJM, the mid-Atlantic grid operator, lets a retired generator's capacity interconnection rights lapse within about a year of deactivation; by the time Crane needed to reconnect, the grid around it had changed enough that Constellation needed 760 MW of interconnection rights transferred from a different retiring plant, approved by the Federal Energy Regulatory Commission only in June 2026.[62] Without that transfer, full grid connection would have waited on PJM's transmission upgrades; in March 2026, a Constellation executive put the date at 2031.[63] A restart with a fully signed, fully financed offtake contract held its 2027 date only by regulatory exception; a converted fossil site that sits idle while financing, siting, and licensing are worked out should expect the same risk, or worse. Once a site is decommissioned past the point of reuse (turbine halls demolished, switchyards dismantled, workforces dispersed), its advantage is gone permanently, and any future nuclear project there reverts to greenfield cost, timeline, and siting risk.
Recommendation: New York should act now to preserve its retired and retiring fossil sites, keeping switchyards, transformers, turbine halls, cooling-water rights, and capacity interconnection rights intact until each has been screened for repowering. The PSC should require the owner of any retiring plant to keep its interconnection and substation in service-ready condition for a defined preservation period, and NYISO should not release the plant's interconnection capacity during that period.

6 DIGITAL TOOLS FOR ACCELERATED PRE-DEVELOPMENT

Pre-development is the most expensive capital in a nuclear program, because at that stage nothing is yet known. New York's own analysis prices equity capital at 35–40% for this phase. Compressing it is worth more per dollar than any other lever available to the state.

New York's timeline leaves no room for conventional pre-development: the Advanced Nuclear Master Plan is due at the end of 2026, the developer solicitation is already underway, and eight communities are waiting to know whether they will host a project. The years a nuclear project typically loses are lost before construction begins, in pre-development. Site screening and selection, feasibility studies, design configuration, licensing preparation, and supply chain and financial planning routinely consume three to five years and tens of millions of dollars before FID is possible.

Proven tools that cut years and cost from pre-development

The REPOWER ACT platform can save New York years and hundreds of millions of dollars in delivering a nuclear program.

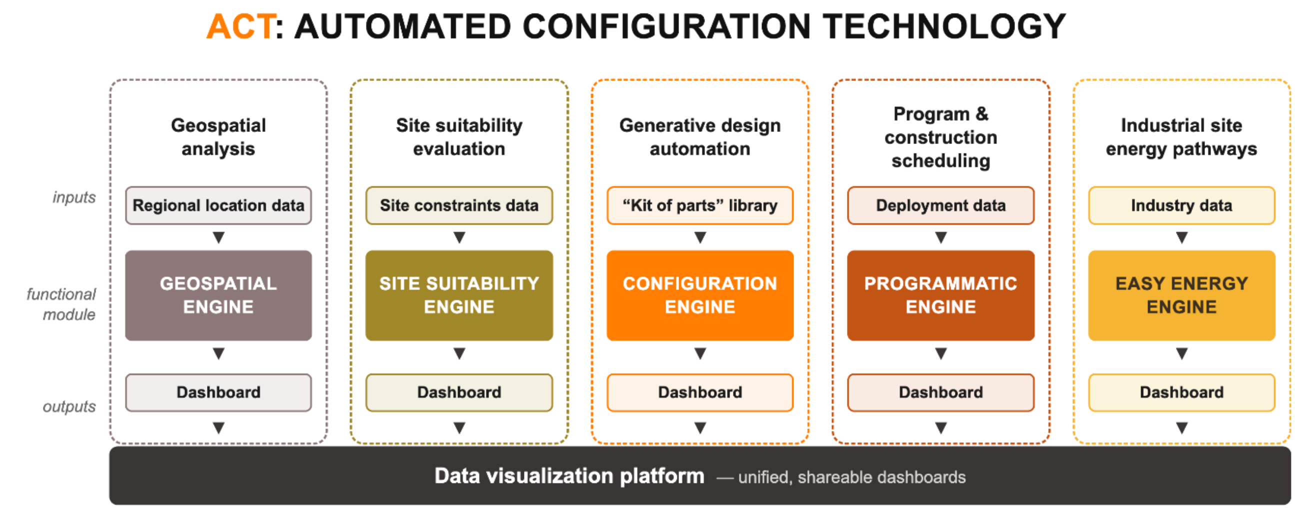
REPOWER ACT was built and tested under a U.S. government program, Project Phoenix, a U.S. Department of State effort to convert coal plants to nuclear. Project Phoenix provides funding and technical assistance to help Central and Eastern European countries transition from coal-fired power plants to SMR nuclear energy. Terra Praxis was selected competitively under that program to lead one of its projects and built the REPOWER ACT platform, developing its configuration engine. Jensen Hughes served as the co-principal investigator, responsible for detailed site characterization and regulatory gap analysis, alongside a partner group spanning LucidCatalyst, EXCEL Services, and the UK design-automation firm Bryden Wood. The platform's digital site screening, selection, and feasibility tools apply the advanced-reactor siting guidance developed by EPRI.[64]

Five engines, one workflow. The platform integrates five analytical engines that feed a unified data visualization layer of shareable dashboards. (Figure 5)

- **Geospatial analysis engine.** Ingests regional datasets (including rail and barge access) to run proximity, intersection, network, and zonal analyses against the site geometry.
- **Site suitability engine.** Translates the geospatial outputs into buildable and no-build areas by applying thresholds across flood risk, seismic hazard (peak ground acceleration, shear-wave velocity, liquefaction), land use, and bearing capacity, rendering the result as a suitability heatmap that can be screened against regulatory and commercial requirements simultaneously.
- **Generative design engine.** Configures an optimized plant layout (Figure 6) from a standardized "kit of parts" for each nuclear design: a hierarchy of assemblies (steam turbines, generators, transformers, condensers, pumps) composed into facilities (reactor block, thermal storage and steam generation, cooling systems, waste treatment, operations and service). A four-step placement pipeline positions the turbine and substation, places the remaining facilities on a structured grid, runs a multi-objective optimization (minimizing the secure site compound and network lengths while holding steam paths below 250 meters), and routes utility networks by shortest path around no-build areas. Where the site type

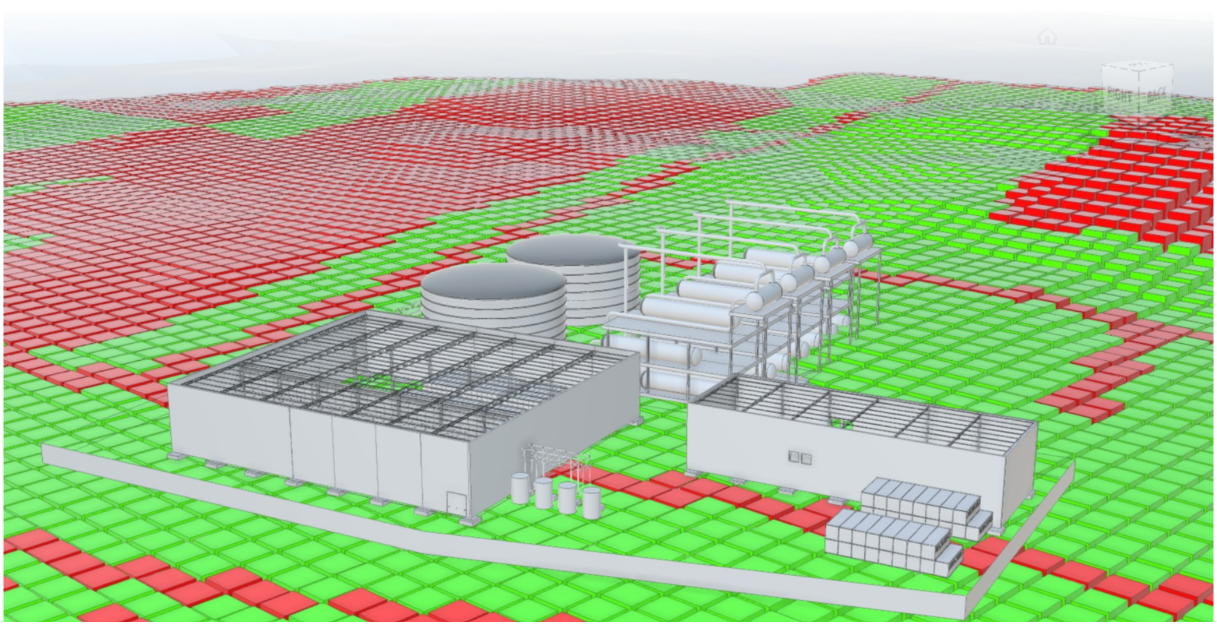
allows, the engine reuses the existing turbine, substation, switchyard, and cooling water infrastructure: the repowering advantage of Section 4.

Figure 5: Automated Configuration Technology: five integrated analytical engines feeding a unified data visualization layer



- **Programmatic engine.** Schedules construction at both site and fleet level, from offsite manufacturing and logistics through standardized foundations and on-site assembly, tracking cumulative capacity as sites are added and enabling scenario comparison across sequencing options. This operationalizes the programmatic delivery model from Section 4.
- **Easy Energy engine.** Identifies the cost-optimal mix of technologies to meet an industrial site's electricity and heat demand, connecting each screened site to the industrial energy markets described in Section 4.

Figure 6: A plant layout generated by the configuration engine from the kit of parts, placed on the site suitability model (green: buildable; red: no-build)



What the platform compresses. A conventional single-site feasibility study takes twelve to eighteen months and produces a bespoke report running up to twenty volumes. The ACT platform generates screening, suitability, layout, indicative cost, and construction schedule outputs for a site in weeks, screens an entire fleet in months, and produces a shortlist ten times faster. The design target for the full project process is five years from conception to operation, against the traditional decade-plus timeframe. The end-to-end workflow, from raw site inputs to deployable layout outputs and dashboards, was demonstrated at fleet scale in December 2025. The methodology and site-by-site results will be presented at International Atomic Energy Agency (IAEA) and Organisation for Economic Co-operation and Development (OECD) forums in 2026.[65]

Gen AI for Licensing

Terra Praxis, in collaboration with Microsoft, has produced a Gen AI for Licensing copilot that has demonstrated the potential to reduce the human-hours required to prepare nuclear licensing and permitting applications by as much as 90%.[66,67] New York already has a live example of what the conventional preparation effort costs. DOE and NYSERDA are jointly funding Constellation's Nine Mile Point Early Site Permit application with a $17.3 million federal grant and up to $12.5 million from NYSERDA, nearly $30 million toward a single site's licensing effort.[68] Applied to New York, the copilot can compress the U.S. Nuclear Regulatory Commission (NRC) construction permit or combined license application; the state's own Article 10 siting proceeding, which governs any generating facility of 25 MW or more and runs in parallel with NRC review; and the state and local permits a nuclear site will require. The July 2024 business and labor coalition letter, citing the state's own Clean Energy Standard review, named permitting and interconnection delays among the reasons the 2030 renewable target is slipping. The same friction is a reasonable concern for nuclear siting, whatever reactor technology is chosen. Combined with the ACT platform, the Gen AI for Licensing copilot extends the automated workflow through licensing preparation, compressing pre-development end-to-end. **Recommendation:** NYSERDA should pilot the copilot on one live New York application, such as the Nine Mile Point Early Site Permit or the first Backbone site's NRC construction permit and Article 10 applications, and measure the hours saved.

Accelerating New York

For New York, the ACT platform can screen every fossil and nuclear site in the state (retired and operating) within months, in time to inform the Advanced Nuclear Master Plan and the Backbone procurement, and the same run produces per-site suitability, layout, cost, and schedule outputs. Those outputs give each solicitation something concrete to bid against. The Gen AI for Licensing copilot can be applied to New York State and federal regulatory frameworks immediately. NYPA's own stated siting criteria (water access, skilled labor, community support, and existing infrastructure) describe a retired fossil site closely.[69]

The earliest capital is the most expensive. The Options Paper prices development-stage equity at 35–40% hurdle rates because, until this work is done, "fundamental uncertainties around constructability, licensing timelines, and project costs remain too high to support underwriting of multi-billion-dollar capital commitments"—money priced against an unknown probability of success.[70] That also makes it the highest-leverage dollar: in the Options Paper's base case, a $160 million pre-FID grant for a first GW-scale greenfield reactor lowers total public support by over $600 million, nearly four-to-one on the state's earliest money.[71]

Availability is a second constraint. The specific pools funding this stage—Regional Greenhouse Gas Initiative (RGGI) Operating Plan grants, NYPA's Backbone development budget—are finite, so the question is whether enough of this capital materializes at all, and fast enough to matter for New York's timeline. **Recommendation**: commit a defined pre-development budget now, from RGGI Operating Plan funds and NYPA's Backbone development budget, sized to screen the full candidate fleet and fund a site dossier for every volunteer community. This does not mean the State funds development to FID. The threshold is a commercially actionable site: community and policy buy-in secured, preliminary data assembled, and enough risk removed that developers compete for it, as New York did for offshore wind. Developers pay their own technology licensing, and the State's preliminary site costs can be reimbursed by the winning developer on award.

Recommendation: defer the choice of reactor technology as long as practicable. The conventional sequence inverts the logic of a competitive market by picking a technology first and building everything else around it. ACT is built for exactly this: its configuration engine can hold multiple competing technologies at once. A single site run then shows which designs fit which sites.

Guarantees and credits transfer pre-development risk to the state; the ACT platform removes part of it, principally the uncertainties around siting, cost, and schedule. When fleet screening takes weeks, site feasibility months, and licensing preparation a fraction of the review hours, deep pre-construction planning becomes a routine early expenditure—run across the whole candidate fleet, at the point where each dollar buys the most risk reduction. With a site's feasibility, layout, cost, and schedule known, success becomes a measurable probability, lowering the cost of capital accordingly. **Recommendation:** structure pre-FID support and cost recovery—the grants NYSERDA has already allocated through the RGGI Operating Plan and the

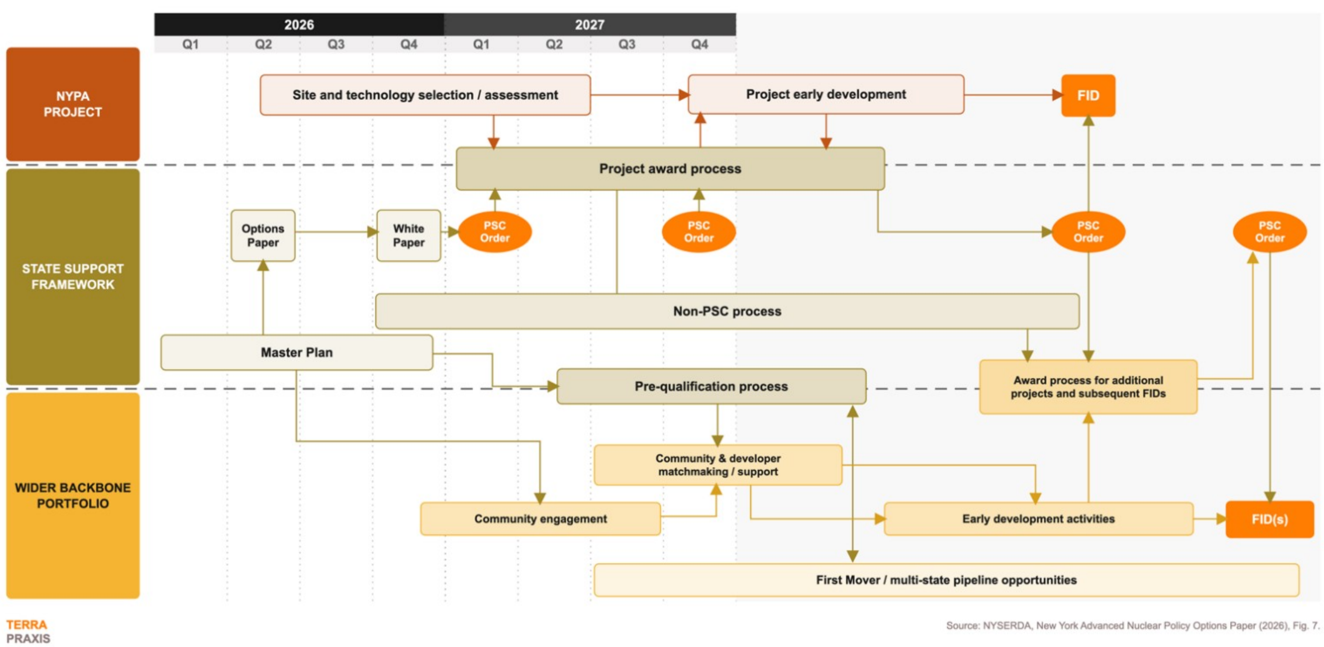
State's other pre-development funds—so that early planning investment is rewarded, as detailed in Section 9: Roadmap.

ACT can give every candidate community the evidence the Options Paper's own engagement process requires. The Options Paper's Next Steps closes by proposing a community engagement process in which host communities "identify and assess sites and build the technical, social and institutional capacity needed to engage with developers on an informed and empowered basis"; a pre-qualification process to determine which developers and technologies are eligible for State support; and NYSERDA-facilitated matchmaking between prepared communities and qualified developers.

ACT gives every candidate community a site dossier—screening, suitability, layout, indicative cost, construction schedule—making it "informed and empowered" in the Options Paper's own sense before matchmaking begins. That matters most for communities that have lost industrial facilities, and with them the resources and skilled professionals such engagement requires. **Recommendation:** the State should fund those site dossiers centrally. Pennsylvania's roadmap proposes routing it through an existing instrument: its PA Sites program already funds engineering, environmental studies, and due diligence at industrial properties, and the roadmap would widen eligibility to cover nuclear-ready characteristics at existing nuclear facilities, retired generation sites, and brownfields with transmission access.[72] The same logic applies in New York: with the dossier funded centrally, a community's ability to participate depends on the screening budget and no longer on the tax base it lost when the plant closed. Those same dossier runs give pre-qualification a should-cost benchmark to test proposals against and let matchmaking convene around a concrete site configuration.

Gen AI for Licensing then compresses the largest items in the Options Paper's pre-FID scope—the preliminary safety analysis, environmental reporting, and permit preparation that make early capital slow as well as expensive. The Options Paper's illustrative timeline in Figure 7 makes the schedule pressure clear: community engagement begins almost immediately, and matchmaking follows within roughly a year—a schedule that leaves no room for conventional 12-to-18-month site studies, and exactly enough for a fleet screened in weeks.

Figure 7: NYSERDA's illustrative process and timeline for the Nuclear Reliability Backbone (Options Paper).



7 THE UNBEARABLE COST OF TIME AND RISK

The arithmetic of time and risk

With federal tax credits and DOE-guaranteed debt but no State support, a first large reactor in New York requires $252/MWh; the State's instruments bring that to $160/MWh. These figures come from the Options Paper's required-revenue analysis, which computes the 25-year contract price, meaning the price per unit of electricity a buyer would need to pay to cover project cash outflows, including the returns debt and equity investors demand during the capital recovery period, under each federal and state support scenario.[73] Absent any support, an initial large reactor requires $408/MWh greenfield or $301/MWh brownfield; a first SMR requires $700/MWh greenfield or $499/MWh brownfield. Layering in the 40% federal Investment Tax Credit and federal loan-guarantee debt brings the large-reactor brownfield figure to $183/MWh. Adding a partial state cost-overrun guarantee and 25-year "Advanced Nuclear Zero Emission Credits" (ANZECs), the Options Paper's own "Base Case," brings it to $132/MWh for a large reactor at a brownfield site, or $192/MWh for a brownfield SMR.[74]

Table 3: NYSERDA's capital cost and schedule estimates for New York's first 1000 MW large light-water reactor, in the Options Paper's case with federal tax credits and DOE-guaranteed debt but no State support.[75]

Metric	Greenfield Land	Brownfield Site
Overnight capital cost (OCC) intensity	$12.8/W	$11.4/W
Deployment schedule (first unit)	12 years	10 years
As-built cost (total capital investment cost, TCIC) intensity	$25.8/W	$19.4/W
As-built cost multiple (TCIC / OCC)	2.0×	1.7×
Required revenue during capital recovery (25 years)	$252/MWh	$183/MWh

The financing-carry trap: A greenfield 1000 MW reactor with equipment and labor worth $12.8 billion ends up costing $25.8 billion by the time it starts producing power, twice as much, even with federal tax credits and DOE-guaranteed debt. The entire difference is the cost of financing the years in between (Table 3). Half of what New York would pay is the price of a twelve-year development-and-construction schedule. Capital recovery accounts for over 80% of the $252/MWh contract price; fuel, operations, and maintenance make up the remainder. This figure compares unfavorably against New York's average wholesale energy price in 2025.[76]

Two levers reduce that cost: build time and cost of capital. Building faster is one lever: moving from a twelve-year greenfield schedule to a ten-year brownfield one—which also lowers upfront capital cost—brings the required price from $252 to $183/MWh. Making the money cheaper is the other lever, and it is the larger of the two. The state's own figures show the annual return investors demand during construction falling, for a large reactor, from 35% for a first-of-a-kind project, to 22.5% with a state cost-overrun guarantee, to 17.5% by the fourth unit in a pipeline.

Figure 8 sets out the relationship. Each curve is one construction-equity rate from the state's hurdle-rate schedule, applied from FID; the two pre-FID years are financed on the Paper's own terms in every case. The horizontal axis is development-plus-construction time, and the shaded bands mark the delivery-model timeframes of Figure 3: bespoke on-site construction at ten-plus years, standardized repeat builds at five to seven, and shipyard-or-factory-built units at two to three.

Equity, at a 35% required return, comes to dominate the as-built cost even though it funds only 20% of construction spend. A reactor is financed with two kinds of money: borrowed money (debt) and investors' money (equity). Until the unit reaches commercial operation, both debt and equity receive no cash, while interest and required returns accrue. In the Options Paper, federally guaranteed construction debt accrues at 5% a year, while first-of-a-kind construction equity for the first large light-water reactor must promise around 35% a year. That 35% is the price investors charge for bearing the risk of total loss if the project fails. Due to the higher rate compounding, even when equity funds just 20% of the spend, it comes to dominate the as-built cost.[77] That is why the state's arithmetic turns one dollar of overnight cost into two dollars or more of as-built cost, why the curves in Figure 8 steepen so sharply toward the upper right. Shortening the schedule and stepping down the equity hurdle through de-risked, repeatable delivery is worth more than any saving on concrete and steel.

Duration is only half of what the delivery model controls. Manufacturing-based delivery also narrows the spread between promised and actual schedule. That predictability lowers the equity cost (moving down the curves in Figure 8) as much as the shorter timeline (moving leftward along the x-axis).

Figure 8: Time is money—advancing up the delivery model ladder materially lowers the capital cost markup under the Options Paper's own financing terms, with the two Section 7 scenarios marked[78]

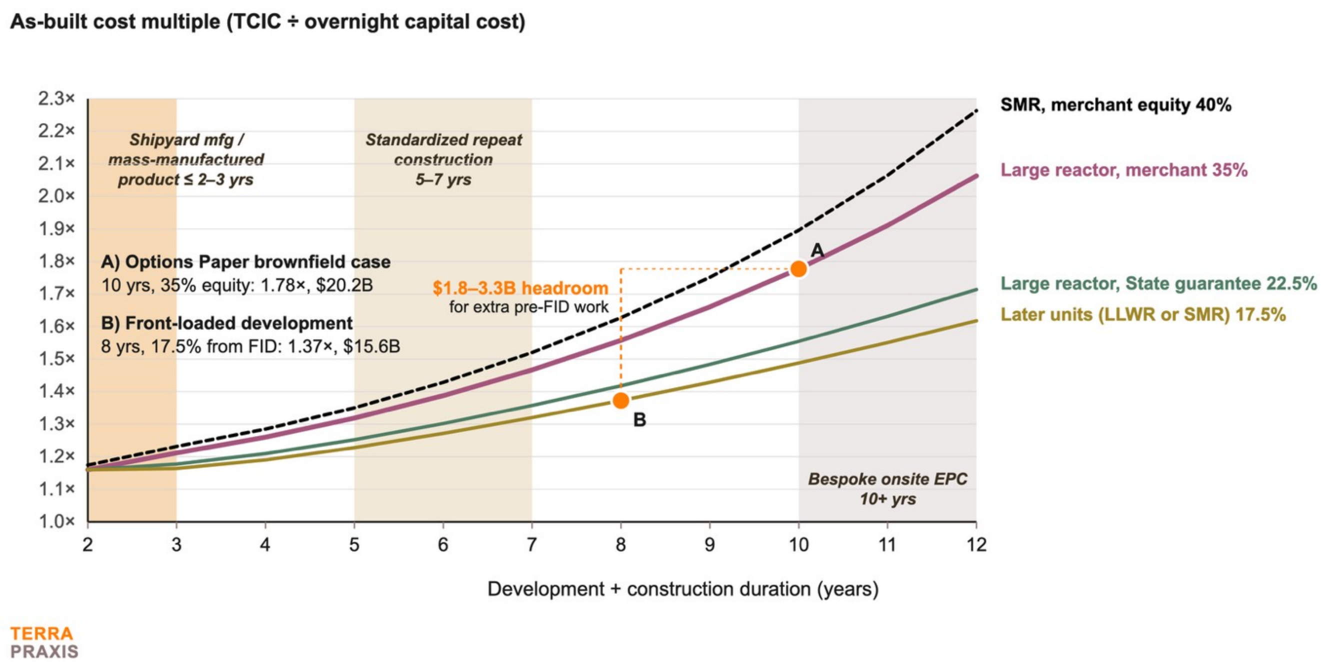


Figure 8 marks the two scenarios. Point A is the Options Paper's own ten-year brownfield case at its 35% equity hurdle; point B, the front-loaded alternative that reaches commercial operation in eight years with 17.5% cost of equity from FID. The conclusion is that the conventional way of building advanced nuclear, one project at a time, on a decade-plus schedule, with private equity bearing the full risk, is unaffordable because of time and the cost of money. The reactor itself is affordable.

Shrink the risk at its source

New York can shrink construction-cost uncertainty at its source, and Barakah proves it. The Options Paper treats New York's nuclear-cost problem primarily as a financial and risk-allocation problem: which party bears construction risk, and how large a tax credit, guarantee, or equity stake is needed to bring the required-revenue price down. Approached this way, the underlying cost uncertainty stays the same size and is divided between ratepayers, the state, and private investors. **Recommendation:** shrink the uncertainty at its source, in addition to allocating it.

LucidCatalyst's "Nuclear Cost Drivers Project", built on a global database of recent nuclear construction projects, documents the clearest recent proof of it.[79] A Korean consortium led by Korea Electric Power Corporation (KEPCO), drawing on Korea's own domestic fleet program since the 1990s, built four APR-1400 units (5.4 GW net) at the UAE's Barakah site for the owner, the Emirates Nuclear Energy Corporation (ENEC), under a predominantly fixed-price, turnkey contract signed in 2009—a project the report concludes "demonstrates that a stick-built approach to large [pressurized water reactor] construction, if done properly, is still very possible without serious delays or cost overruns." On the same all-in, as-built basis this discussion paper uses throughout, Barakah is reported at $24–32 billion ($5–6/W, 2026 $), less than half the five-reactor pipeline the Options Paper models ($13.4/W, on the same all-in, as-built basis), even after full learning. Barakah's schedule did slip: Unit 1 was planned for 2017 and entered commercial operation in 2021, largely because of operator licensing and training, and Unit 4 followed in 2024, and the as-built figure grew from a roughly $20 billion 2009 headline contract. Even so, the construction itself held close to plan, each unit came in faster and cheaper than the one before, and the four-year slip on a four-unit program compares with seven years at Vogtle and thirteen at Olkiluoto 3. The study also identified eight key cost drivers and 35 credible cost-reduction opportunities behind the pattern Barakah illustrates; on the strength of that analysis the UK adopted a 30% cost-reduction target as national policy. Across that same database, the projects that invested most in pre-construction planning achieved the lowest costs and the greatest risk reduction.

Case study: a first-of-a-kind delivered on schedule. Kashiwazaki-Kariwa 6 and 7, Japan

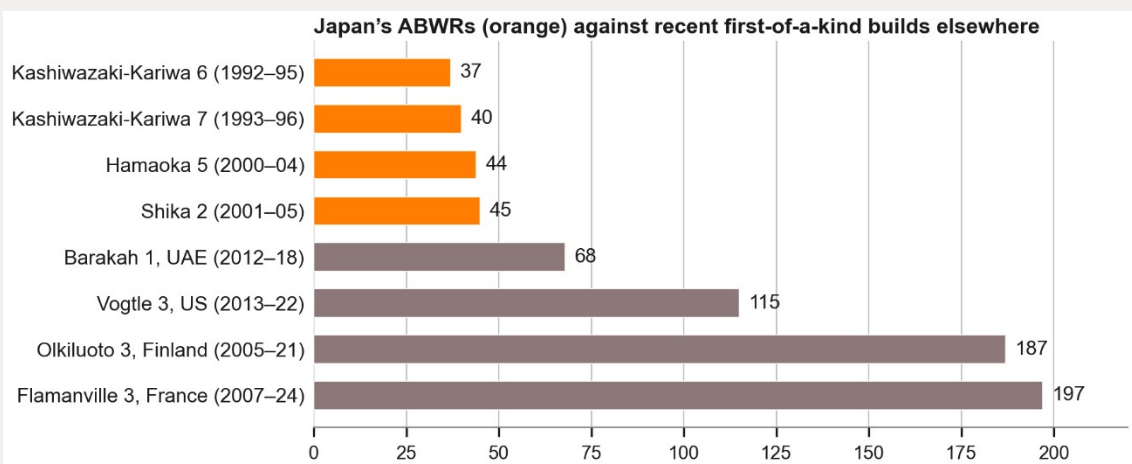
Tokyo Electric Power Company Holdings (TEPCO)'s Kashiwazaki-Kariwa units 6 and 7 were the world's first advanced boiling water reactors, 1,356 MW each, with first-of-a-kind reactor internal pumps, fine-motion control rod drives, a reinforced-concrete containment and full digital control. Unit 6 went from first concrete in November 1992 to first criticality in 37 months and to commercial operation in November 1996; unit 7 followed in July 1997. Construction was nearly a year shorter than any earlier boiling water reactor in Japan, and TEPCO judged that without the extra first-of-a-kind testing it would have taken about 48 months. The two ABWRs that followed, at Hamaoka and Shika, were built in 54 and 55 months (Figure 9).[80]

None of it was luck. The design was standardized from 1981 by three vendors, six utilities and the government; the basic design was complete before the licence application and the detailed design before the construction permit. Every deviation from proven practice was tested before use. Construction planners and designers sat in the same room, and no drawing was finished until it had passed a constructability review. Unit 6 was built under an all-weather cover erected before the floors and walls; unit 7 from large factory-built modules set by a 930-tonne crane, so civil, building and mechanical work ran in parallel. TEPCO ran the program itself under split-package contracts, with a steering committee across owner and suppliers and 3,700 owner inspections.

As part of the interviews carried for the ETI Nuclear Cost Drivers Project, the Hitachi team indicated that every dollar spent before construction saved six after during construction. This is consistent with empirical evidence and systems engineering practices for complex projects, where detailed front-end engineering and early verification reduce construction risks and costs.[81]. A GE Hitachi engineer seconded to a later ABWR site described a site kept "as clean as a factory," where each worker's daily task, weld standard and inspector were specified in advance. Barakah's chief executive put it another way: he would delay the start of construction rather than start with an unfinished design.[82]

The lesson for the Backbone is that first-of-a-kind does not have to mean first-of-a-kind delivery. New York should make State support conditional on a completed design and a constructability review before FID; fund the pre-construction engineering, the cheapest dollars in the program; buy repeat units at the fewest sites so the same teams carry the learning from unit to unit; and build the owner's program office that runs the steering committee and the inspections. The Options Paper's pre-development phase is where that investment belongs.

Figure 9: Construction time, first concrete to construction completion — Japan's first ABWRs against four recent first-of-a-kind builds.



Months from first concrete to construction completion: first criticality for the ABWRs, fuel load for Vogtle, Olkiluoto and Flamanville, ENEC's construction-complete date for Barakah, which reached commercial operation in 2021 after operator licensing. Dates and sources: endnote 80.

Kashiwazaki-Kariwa exposes something a mechanical reading of Figure 8 hides. Because construction equity is expensive, the instinct is to spend as little as possible before FID. That instinct is costly. On the Options Paper's own terms, its first large reactor at a repowered site takes ten years — two of them pre-FID development — with federal debt at 5% covering 80% of construction and private equity at 35% (point A in Figure 8). Its as-built cost at commercial operation is $20.2 billion. A front-loaded alternative costs $15.6 billion (point B): spend more before FID so the design is complete and the site work done, construction equity costs 17.5% from FID, and build in six years, with commercial operation in eight. The $4.6 billion gap between them is carry, not concrete—

the overnight cost is identical in both, and carry falls from roughly four-fifths of it to roughly a third. That gap is the budget for that extra pre-FID work. Financed on the Paper's pre-FID terms, a developer could spend an additional $1.8 billion and still break even; if the State funded it at its own 5% cost of capital, with the selected developer repaying upon securing the site lease, the ceiling would rise to $3.3 billion.[83] Not only do these figures dwarf the Options Paper's $160 million pre-FID grant, every repeat build benefits from these investments.

Two consequences follow for New York. First, the public support the Options Paper models goes further if it backs a standardized program with a firm, multi-unit order book. Second, standardization alone will not get costs below $100/MWh without deeper subsidy; that requires moving past on-site construction to the manufacturing-based delivery models the New Nuclear World study prices at $40–90/MWh.

The first consequence points toward an option already on the Options Paper's own menu: the "Committed Pipeline"—committing the full 5 GW upfront to a single mature design, such as the AP1000, to capture the workforce, supply-chain, and vendor-queue benefits Korea's history demonstrates. However, in the United States, while the AP1000 is proven technology it remains delivery-unproven. Committing the whole program would buy a certainty that does not yet exist and would foreclose the paths repowering depends on: an AP1000-class reactor does not graduate out of megaproject delivery no matter how many times it is repeated. Barakah's own fourth unit, after a 58% cost reduction[84], was still a stick-built project. Reaching the manufacturing-based delivery tier described in Section 4 requires keeping that door open.

This paper takes no side between the AP1000 and small modular reactors; it takes a firm side on the delivery model. The AP1000 is a proven technology without, as yet, a proven cost-effective delivery model in the United States; the manufactured designs now reaching first criticality are promising and unproven. A program that starts on the standardized rung with a proven design and holds lanes open for the shipyard and factory rungs, deciding on delivery evidence at each tranche (Section 4), is the no-regrets position, and it is what Option 3 allows.

Recommendation: adopt the Options Paper's own "Option 3", which commits a first tranche of a proven design, enough to start the workforce and supply-chain learning curve now, and defers the technology choice for the rest of the pipeline until deployment results are in. The Paper's stated pivot is to whichever technology then proves lowest-cost; Terra Praxis recommends structuring those decision points as the delivery-model gates set out in Section 4, so that shipyard and factory delivery are admitted as they prove out, whatever the reactor class. This keeps the 5 GW from being committed in one irreversible choice.

The Options Paper suggests a technology-neutral pre-development phase but never funds one. Its Next Steps start with community site assessment and a pre-qualification process that determines which developers and technologies qualify for State support. Its own funding and timeline assumptions then close that window almost immediately. The illustrative timeline pairs communities with developers within about a year, and the financing model prices the entire pre-FID phase as a single chosen design's development from day one, with FID at the start of year three.

Recommendation: add the instrument the Options Paper omits: state-held, design-agnostic site development up to and including NRC Early Site Permits, which keeps that window open. Buyers who have succeeded at nuclear procurement followed that longer sequence before any tranche is committed: validate sites, advance licensing and interconnection work, engage communities, and quantify the real siting, cost, and schedule requirements of each candidate design class, large light-water, SMR, and manufactured microreactor alike. The choice of reactor technology is then made against evidence and competition. Sequenced that way, every pre-development dollar can do double duty for New York. It de-risks the winning design, and it makes the state's order book more attractive to every vendor competing for it. **The buyer's leverage compounds while the options stay open.**

Shipyard and manufacturing-based delivery is arriving now. In July 2026, Constellation Technology Ventures made its first strategic investment in a U.S. small modular reactor developer, backing Blue Energy's robotic, shipyard-style prefabrication of GE Vernova Hitachi's BWRX-300 units for a targeted 2.5 GW gas-to-nuclear project in Texas aiming for power in 48 months or less.[85] Between June and August 2026, five U.S. microreactor designs reached first criticality under the federal Reactor Pilot Program.[86] While these were zero-power demonstrations, the companies that ran them built to an assembly-line factory model, with development timelines measured in months. Keeping the design-agnostic window open is the precondition for choosing wisely among the options already set out by the Options Paper, and it is the work the ACT platform automates and the Roadmap (Section 9) includes in its first six months.

The informed buyer

This paper offers two further recommendations for New York, one for how the state organizes itself as a buyer and one for how it licenses what it buys.

1. **Structure NYPA as an informed buyer with in-house technical capability.** This means a program office able to specify the scope, estimate what it should cost, evaluate bids, and enforce schedule and budget through the contract, while a single accountable delivery organization on the developer side holds project management, engineering, licensing, and commissioning: the split between ENEC and KEPCO at Barakah. The role does not require NYPA to own or finance the plant; ownership and financing can sit with any of the structures the Options Paper sets out. The Options Paper is silent on buyer capability. The Roadmap (Section 9) names it as an explicit action.

Being an informed buyer accomplishes two things, and New York needs both. The first is narrowing the cost range. Investors price the full range of uncertainty. The wide gap between the Options Paper's high- and low-cost cases, priced at a 35% required return, is exactly what New York pays for that uncertainty. A buyer with engineering, cost, and schedule capability of its own can estimate what a project should cost before soliciting bids, test vendor and EPC proposals against that estimate, and enforce budget and schedule during execution. This narrows the range, and with it the risk premium, at its source.

The second advantage for New York is aligning incentives across the half-dozen organizations that make up a nuclear program: technology vendor, EPC, major suppliers, constructor, and operator. Vogtle and Barakah show that a capable, engaged owner and a clear chain of command matter more than how many roles one firm holds. At Vogtle, Westinghouse's triple role—nuclear system supplier, plant design engineer, and consortium leader—sat inside a sprawling consortium whose ownership kept shifting as costs escalated[87]; the fixed-price EPC contract left the owner legally exposed to forfeiting its own protections the moment it tried to manage the work, and litigation between project participants is among the indicators the Nuclear Cost Drivers study uses to score the resulting governance cost driver.[88] Barakah took the opposite structural path to the same underlying fix: a single prime contractor held clear responsibility and authority atop an experienced consortium, under an owner built for exactly that oversight role.

ENEC built that owner capability deliberately: it ran a year-long, 75-expert evaluation of three competing consortia—led by KEPCO, AREVA, and GE-Hitachi—for the four-unit order, and held its commercial requirements, including a single consolidated prime contract, firm through the competition; the vendors adjusted to the buyer.[89]

Fixed-price contracts remain available to an informed buyer. The Options Paper expects Western EPCs to refuse all construction risk under a fixed-price bid, but the record is narrower: KEPCO accepted a predominantly fixed price in 2009 because an informed owner ran a genuine competition for a consolidated, fully specified scope. What failed at Vogtle was fixed-pricing an incomplete design through a conflicted contractor structure. Fixed price remains available, and its price depends on buyer competence. Hinkley Point C's mid-project corrective was the same move: four contractors merged into a single incentive-shared alliance for the plant's mechanical, electrical, and HVAC phase.[90]

The Options Paper notes the same risk from a different angle. Its procurement discussion warns that a lowest-price request for proposals (RFP) paired with a government share of cost overruns invites unrealistically low bids. The remedy is de-risking work done before bids: someone must complete it before the project can be built at a defensible cost. What is undecided is who does it, and who keeps the value it creates.

An investor supplying equity at a 35–40% required return does not passively collect that return. The investor installs the discipline: a completed design, an integrated schedule, an experienced constructor. The investor then keeps the difference between the risk it priced and the risk it removed. An informed buyer enforces the same discipline before price negotiation, so the de-risking shows up in the bids and the value accrues to ratepayers. **Recommendation:** NYPA should build this capability before FID and put it on the program's critical path: an in-house should-cost estimate to negotiate against, and incentive alignment written into the contract architecture.

2. **Accept a proven design with only narrow, justified, project-specific license modifications, and no full bespoke re-review.** This practice from Barakah should apply evenhandedly to whatever design is under review, including manufactured designs once they clear an initial demonstration.

New York does not need to design this analysis-to-policy sequence from scratch. The UK has already run three of its four steps. First came the analysis, in the Nuclear Cost Drivers study. Then, in the 2018 Nuclear Sector Deal, the government adopted a quantified 30% cost-reduction target as national policy. Third, the Nuclear Industry Council's 30% Cost Reduction Working Group drafted a table of industry actions anchored to the eight cost drivers, each assigned to an owner among developers, plant owners, suppliers, or government, and offered it as the basis for a sector-wide agreement. The fourth step was never taken. Support was never made contingent on the actions, the Sector Deal's target lapsed, and the agreement stayed voluntary.[91]

The Options Paper has completed the first step for New York, and it endorses the same practices: complete design before construction, constructability reviews, resource-loaded integrated schedules, lifecycle risk registers, and aligned cost incentives. **Recommendation:** New York should take the two steps the UK started and left unenforced. The first is to make each state support instrument (ANZECs, cost-overrun guarantee, State equity, and pre-FID grants) contingent on systematic application of those practices. The second is to set a quantified, jointly owned cost-reduction target for the Backbone program with named action owners. The state's hurdle-rate table already quantifies why this works: support buys compliance, and compliance shrinks the construction risk the support is priced against. The guarantee itself should be scoped to risks the developer cannot control, such as licensing delay or loss of site access, while delivery risks stay with the contract; a guarantee that also covers delivery removes the incentive the cost-reduction target is meant to create.

Recent Western builds show the cost of bad starting conditions, and Hinkley Point C also shows that learning between units is real. Vogtle finished roughly seven years late at a total of more than $30 billion,[92] and Finland's Olkiluoto 3 finished some thirteen years late at about €11 billion against a €3 billion fixed price.[93] Hinkley Point C, still under construction, was re-estimated by EDF in February 2026 at £35 billion in 2015 prices, about £48 billion in today's money and nearly double the £18 billion at its 2016 investment decision, with Unit 1 now due in 2030 against an original 2025; it will be among the most expensive nuclear plants ever built. It went wrong through the starting conditions this paper warns against: a first-in-a-generation project, begun with an incomplete design, without a modern supply chain or experienced workforce, and with private capital carrying the full construction risk at full price. Every one of those conditions was locked in years before the UK's cost-drivers evidence and industry agreement existed. Yet even at Hinkley Point C, the learning curve from one unit to the next was measurable and immediate. Unit 2's excavation ran 15% faster than Unit 1's and its spray-concrete work 30% faster, with right-first-time rates reaching 95%. Experienced crews move directly to Sizewell C, the replica project, which under government-backed financing is expected to cost about a fifth less to build.[94,95]

Financing structure is the design choice that most determines whether a schedule slip is survivable, and Hinkley Point C and Sizewell C differ on it. Hinkley Point C is financed through a contract-for-difference that pays nothing until power flows, so every year of delay compounds against the project no matter how high the strike price. Sizewell C switched to a regulated-asset-base structure that begins recovering financing costs during construction; the same process of cost recovery during construction kept Vogtle's regulated owners in cheap capital, and also put the overrun on Georgia ratepayers.[96] Any New York version needs a cap or sharing rule so the financing benefit does not become an open-ended ratepayer guarantee. New York's own Options Paper puts an analogous lever on the table for the Backbone: a construction work in progress (CWIP) provision under utility ownership, and a provision for revenue during construction (PRDC) grant variant.[97] Each would pay a share of financing costs as they are incurred, so they stop compounding to commercial operation. This moves a project down the curves in Figure 8, which are built on the Paper's own financing terms, where nothing is repaid until completion. **Recommendation:** adopt one of these construction-period recovery mechanisms for the Backbone. Learning between units cannot repair financing conditions set before first concrete.

Recommendation: fix those conditions before the first unit. Georgia and Britain each derived them afterward from a failed project. The Nuclear Cost Drivers database includes a back-check against the historical record, and it shows that low-cost delivery has a domestic precedent. The best of the United States' historical fleet, restated in current dollars at a standard financing assumption, matches today's low-cost international programs. The United States has built nuclear power this cheaply before, and New York can lead in doing so again.

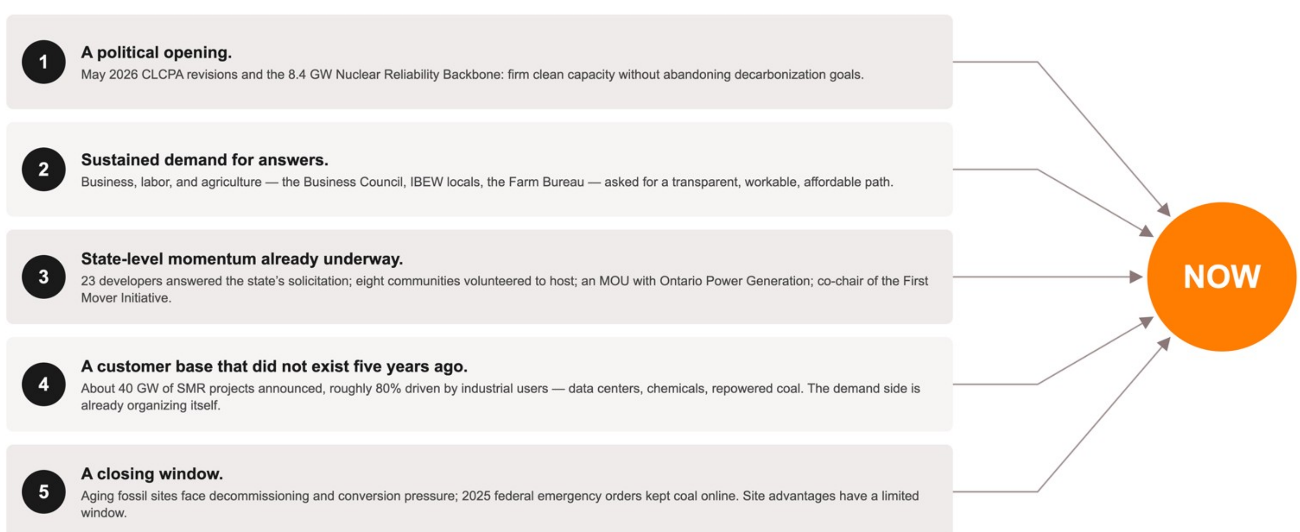
8 WHY NOW: A CONFLUENCE OF CONDITIONS

Several conditions have aligned for New York in a way that did not exist five years ago (Figure 10):

- **A political opening.** The announcement of the 8.4 GW Nuclear Reliability Backbone in the January 2026 State of the State, the May 2026 budget revisions to the CLCPA, and the Commission's June 2026 Order establishing the Backbone process came within six months of one another: evidence that New York can recalibrate its climate strategy toward firm clean capacity under cost and reliability pressure, without abandoning its decarbonization goals.

- **Sustained demand for answers.** The coalition spanning business, labor, and agriculture, including the Business Council of New York State, IBEW locals, the New York Farm Bureau, and regional chambers of commerce statewide, wrote to Governor Hochul's office in July 2024. It asked for a transparent, workable, affordable path to the state's clean energy goals.
- **State-level momentum already underway.** New York has announced the 8.4 GW Nuclear Reliability Backbone plan, run a developer solicitation that drew 23 potential developers, with eight communities volunteering to host, signed a memorandum of understanding (MOU) with Ontario Power Generation on advanced nuclear collaboration, and taken on the role of co-chair of the multi-state Advanced Nuclear First Mover Initiative. Terra Praxis proposes to support that momentum with ACT site screening and cost benchmarking, and Gen AI for Licensing.
- **A customer base that did not exist five years ago.** Roughly 40 GW of SMR projects are already announced across North America and Europe, and about 80% of that pipeline is driven by industrial energy users, with the remainder largely from utilities: Amazon, Google, and Equinix in data centers, Dow and Tata Chemicals in chemicals, and coal-repowering commitments. A New York Backbone procured programmatically would anchor a demand side that is already organizing itself.
- **A closing window.** The fossil sites that could make repowering fast and cheap are aging assets under significant pressure to be decommissioned or converted. Surging demand required federal emergency orders in 2025 simply to keep enough existing coal capacity online. New York's retired and aging fossil sites, like those nationally, have a limited window before their site advantages are lost.

Figure 10: Why now: several conditions have aligned for New York in a way that did not exist five years ago.



9 WHAT IS REQUIRED: A PHASED ROADMAP

The recommendations made throughout this paper are gathered here as a sequenced roadmap. Each item is an action for New York State, NYPA, NYSERDA, or the PSC to take.

Months 1–6: Screen and scope

- **NYSERDA:** to inform the "Advanced Nuclear Master Plan" due at the end of 2026, commission fleet-wide screening of New York's full inventory of retired and operating coal, oil, and gas sites against NYPA's stated siting criteria, using a platform such as ACT that can screen the full fleet within months.
- **PSC and NYISO:** require the owner of any retiring fossil plant to keep its switchyard, transformers, cooling-water rights, and capacity interconnection rights in service-ready condition for a defined preservation period, and hold that interconnection capacity in the queue, until the site has been screened

for repowering. This is the most time-critical action in the roadmap; Section 5 sets out why.

- **NYSERDA:** provide each community that volunteered to host with a site dossier, so that NYSERDA's community engagement and matchmaking process starts from evidence.

- **NYSERDA and NYPA:** keep the pre-development phase neutral on reactor technology, and begin design-agnostic Early Site Permit preparation for the leading sites. Structure site work, licensing preparation, and interconnection studies to support large light-water, SMR, and manufactured designs alike, so that competition among design classes survives into procurement.

Months 7–18: License and structure

- **NYSERDA:** pilot the Gen AI for Licensing copilot on one live New York application, such as the Nine Mile Point Early Site Permit or the first Backbone site's NRC construction permit and Article 10 applications, and measure the hours saved.

- **NYPA, with the PSC:** develop a financing structure for the anchor 1 GW project around the Commission's decision on the cost-overrun-guarantee and ANZEC options.

- **NYPA:** structure the Backbone's procurement as a program (the Options Paper's Option 3): a firm, near-term order book for an initial tranche of a single proven design, with repeat units concentrated at the fewest viable sites. Write the delivery-model gates of Section 4 into the procurement, so that Option 3's deferred choice for the later tranches admits shipyard and factory delivery as each proves out, and avoid a single irreversible commitment for the full 5 GW of new build.

- **NYPA:** continue New York's shift from lowest-price RFPs toward competitive negotiations that establish realistic risk-sharing agreements.

- **Governor's office and NYPA:** structure NYPA as an informed-buyer program office, with the engineering, cost-estimating, and contract-management capability to specify the anchor project, evaluate bids against a should-cost estimate, and enforce schedule and budget, and require a single accountable delivery organization on the developer side.

- **NYSERDA, in the developer and technology pre-qualification process:** adopt a standing principle of accepting proven designs with only narrowly justified, project-specific modifications, applied evenhandedly to manufactured designs once they clear an initial demonstration.

- **Governor's office, NYSERDA, and the PSC:** adopt a New York analog of the UK's Sector Deal agreement between government and industry. Set a quantified cost-reduction target for later units, and make every support instrument, meaning ANZECs, the overrun guarantee, State equity, and pre-FID grants, contingent on the delivery practices the Options Paper endorses. Assign a named action owner for each cost driver.

- **NYPA:** commission a New York-specific "should-cost" model for repowered sites, seeded with the screening's per-site cost and schedule outputs, so that bids are negotiated against evidence. PSC: structure pre-FID cost recovery to reward early planning investment, preferring mechanisms that begin recovery during construction, such as Sizewell C's regulated asset base and Georgia's Nuclear Construction Cost Recovery tariff, over structures that pay nothing until commercial operation.

- **NYPA:** deepen the Ontario Power Generation collaboration, and New York's role in the Advanced Nuclear First Mover Initiative, to share pipeline risk and supply-chain learning.

Months 19–36: Commit and build

- **NYPA:** bring the anchor project to FID with its selected development partner, under the financing structure agreed with the Commission. An NRC Early Site Permit typically takes one to two years to prepare and two to three years to review, so if the state follows the design-agnostic Early Site Permit path recommended in Section 7, FID on that basis falls at the end of this window at the earliest.

- **NYPA's development partner:** file the NRC construction permit or combined license application for the first repowered site, building on the Early Site Permit work NYPA and NYSERDA began in months 1–18; construction starts on NRC authorization, on the ten-year brownfield schedule.

- **NYSERDA and NYPA:** extend site screening and licensing work to the additional sites required to reach the Backbone's full 5 GW of new build.
- **NYPA and Empire State Development:** engage hyperscale data center operators and large industrial energy users on power purchase agreements and process-heat offtake at repowered sites, testing in practice the beyond-electricity case.

10 CONCLUSION

New York has decisive advantages Ontario did not have when its reckoning arrived: an announced Nuclear Reliability Backbone, a NYPA directive to deliver 1 GW upstate, eight volunteer host communities, and two demonstrated digital tools that compress site screening and licensing from years to weeks.

The case for repowering rests on three findings already in the record. Every decarbonization pathway the "2025 Energy Plan" models costs more than doing nothing through 2040 on energy-system cost, and firm clean capacity is required to hold reliability. Brownfield siting measurably lowers cost and shortens schedule, and the largest learning rate in the state's own cost model applies only to repeat units built at the same site. And the delivery model, more than the technology, sets the size of the nuclear market.

Procuring the Backbone as a standardized, repeat-build program at repowered sites therefore does more than lower New York's costs. It puts the state's sites, workforce, and supply chain at the front of an industrial market worth $0.5–1.5 trillion, driven by the data center, chemical, and manufacturing customers its economic strategy is built to attract. That supply chain runs through New York's host communities and its wider manufacturing base. The Options Paper's own economic-impact modeling already finds manufacturing capturing 15–19% of construction-phase jobs on a representative reactor build, before New York deliberately expands that capacity.[98] Its supply-chain appendix identifies concrete opportunities the state's industrial base is positioned to capture now—nuclear-grade cement and rebar steel, industrial pumps and valves, and electrical measurement and detection systems—with reactor pressure vessels and steam generators as further, larger-investment opportunities.[99] A manufacturing-driven, standardized delivery model turns that list into an order book New York's manufacturers can invest against. Albany County has already moved to capture this: its Legislature adopted Local Law "H" of 2025 on February 9, 2026, amending the county code to fund the development of parts and components of advanced nuclear technologies as a qualifying "green business" activity.[100] The window is the constraint. Every fossil site decommissioned past the point of reuse is one the state cannot get back.

11 ENDNOTES

[1] New York (2025), New York State Energy Plan 2025, Pathways Analysis chapter: "final energy served by electricity increases from 19 percent in 2025 to 26–29 percent in 2040, and final energy served by direct fossil fuel consumption … decreases from 78 percent in 2025 to 63–69 percent in 2040."

[2] NYSERDA (June 2026), NYSERDA and DPS Announce Publication of Advanced Nuclear Policy Options Paper. *The Paper's technical and cost analysis was prepared for NYSERDA by The Brattle Group, with input from MIT and Sargent & Lundy.*

[3] Options Paper, Appendix B. Market Assessment. B.1 Completed Projects. Barakah 1–4 (UAE). A roughly $1 billion contractor overrun dispute on the $20.4 billion contract, and commercial-operation dates that slipped for operator-licensing and readiness reasons—and still concludes the project was "notable for realizing substantially lower costs and less delay than other recent projects outside Asia."

[4] Power Technology (September 2024), Barakah Nuclear Power Plant, UAE. Reports about $32 billion. World Nuclear Association (updated July 2026), Nuclear Power in the United Arab Emirates, gives $24.4 billion; no official final cost has been published.

[5] Options Paper, Appendix D, Table D-10 (Scenario P-1a: Single Pipeline, 5 LLWRs): total pipeline cost $66.9 billion for 5 GW ($13.4/W), reflecting learning-curve cost reduction from $12,756/kW (unit 1) to $9,019/kW (unit 5).

[6] Options Paper, Section 2.3 ("Benefits and Costs of the Backbone"), p. 8: two nuclear-deployment scenarios (low end: 2.2 GW by 2040 / 4.8 GW by 2050, net system benefits of $28.1 billion by 2040 and $47.2 billion by 2050, NPV; high end: 3.3 GW by 2040 / 5.6 GW by 2050, $31.1 billion and $54.2 billion, respectively), relative to a baseline of decarbonizing the grid without nuclear. Public support cost and pipeline sensitivity figures: Appendix C ("Cost Analysis—Inputs and Methodology"), Table C-1 (overnight capital costs, hurdle rates) and Appendix D ("Cost Analysis—Results")

[7] Options Paper, Appendix A, Table A-3. Total value added over a 40-year operating life, per gigawatt: $15 billion for the LLWR and $20 billion for light water SMRs (lwSMR), undiscounted 2025$.

[8] LucidCatalyst (November 2025), A New Nuclear World: How Small Modular Reactors Can Power Industry, *commissioned by Urenco with support from the World Nuclear Association*

[9] U.S. Department of State (November 2022), Special Presidential Envoy for Climate Kerry and Ukraine Minister of Energy Galushchenko Announce Cooperation on a Clean Fuels from Small Modular Reactors Pilot, COP27 Climate Conference

[10] Terra Praxis (November 2024), Terra Praxis Offers AI for Licensing Capabilities

[11] Microsoft (March 2026), Aalo Atomics sees 92% cut in permit time with Azure, saving $80M yearly. Faster execution lowers the required number of human review hours.

[12] Options Paper, Appendix A: $2,198M ÷ $13,403M from Table A-2, on the greenfield overnight-cost basis stated at p. A-5; local content percentages at pp. A-3 and A-5, derived from an identification of nuclear-related firms already operating in New York (an IMPLAN analysis by BW Research Partnership for The Brattle Group, applied to EIA capital cost data).

[13] Team Pennsylvania (June 2026), Pennsylvania Nuclear Energy Roadmap pp. 10, 18, 20, 45.

[14] NYSERDA (2025), Patterns and Trends: New York State Energy Profile, 2009–2023, Out-of-state energy expenditures of $36.8 billion of total 2023 spend of $73.7 billion, roughly 50%.

[15] Ibid. Table B-10: NYS total energy expenditures of $80.0 billion in 2022 (the highest of the fifteen years shown) and $73.7 billion in 2023.

[16] DPS & NYSERDA (July 2024), Draft Clean Energy Standard Biennial Review

[17] Business Council of New York State et al. (July 2024), Statement Regarding CLCPA Letter Calling for Answers to Key Policy Concerns.

[18] NYISO (July 2026), 2025–2044 System & Resource Outlook; NYISO Report Highlights Need for New Generation and Transmission Investment to Meet Growing Demand and State Policy Targets

[19] U.S. Energy Information Administration (April 2026), U.S. coal-fired generating capacity retired in 2025 was the least in 15 years

[20] New York (2025), New York State Energy Plan 2025

[21] Denholm et al. (June 2021), The challenges of achieving a 100% renewable electricity system in the United States. *Joule*

[22] NYSERDA (September 2024), The Cost of Offshore Wind in New York (weighted-average nominal Strike Price of $150.15/MWh for Empire Wind 1 and Sunrise Wind under the fourth offshore wind solicitation, NY4); NYSERDA (June 2024), Governor Hochul Announces the Finalization of Contracts for Two Offshore Wind Projects.

[23] Calculated from NYISO OASIS, LBMP – Day Ahead – Zonal (Zone K, Long Island), 2024 hourly data, demand weighted average.

[24] New York State Department of Public Service, Key Credit Collection Beginning 2010 (quarterly residential collection data, PSC Case 91-M-0744), December 2024 reporting period: 1,383,480 residential customers 60+ days in arrears across the State's ten largest electric and gas utilities, owing $1,857,532,007 in aggregate.

[25] Terra Praxis (August 2023), Risks to the Energy Transition

[26] Wolken (March 2026), Advanced Manufacturing Growth and Practical Climate Leadership in New York State.

[27] Business Council of New York State et al. (July 2024), Statement Regarding CLCPA Letter Calling for Answers to Key Policy Concerns.

[28] NYSERDA (September 2025), Zero by 40 Technoeconomic Assessment, pp. S-1, 1, 3. *Prepared by the Electric Power Research Institute*

[29] Ibid, p. S-22 and pp. 355–356 ("Conclusions").

[30] Joint Utilities of New York (May 2026), Coordinated Grid Planning Process: Cycle 1 Report. DPS Case 20-E-0197 filing. The scenario capacity-expansion model was built and run by the NYISO (results: Appendices C and D); the six investor-owned Joint Utilities—Con Edison, Orange & Rockland, National Grid, NYSEG, Rochester Gas and Electric, and Central Hudson—conducted the transmission analysis and project selection jointly with Department of Public Service Staff, under Public Service Commission oversight, with NYSERDA and the Energy Policy Planning Advisory Council participating. Capacity results: Figures 11–12; local-transmission headroom (9 GW HCLO vs. 12 GW State): p. 52. The HCLO ("High-Capital Cost, Low-Operating Cost") Scenario is the report's pathway in which "a nuclear like, firm, DEFR resource is available." DEFR is the report's term for a dispatchable emissions-free resource.

[31] O'Boyle, et al (April 2024), The 2035 Report: Reconductoring With Advanced Conductors Can Accelerate The Rapid Transmission Expansion Required For A Clean Grid. *Energy Innovation*

[32] Princeton University (October 2021), Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report Summary. pp. 9, 27–30. E+ RE-: 306,000 GW-km added, +96% (~2x) over 2020, ~260 GW of new advanced nuclear deployed by 2050. E+ RE+: 1,309,000 GW-km added, +409% (~5.1x) over 2020, no new nuclear construction, existing fleet retired early. E+: 673,000 GW-km added, +210% (~3.1x) over 2020, existing nuclear fleet largely retained with modest new nuclear additions

[33] Joint Utilities of New York (May 2026), Coordinated Grid Planning Process: Cycle 1 Report: utility project costs recovered pursuant to the Cost Sharing and Recovery Agreement (CSRA) approved by the Commission—the utility-rate-recovery mechanism for transmission capital.

[34] Grid Strategies and Americans for a Clean Energy Grid (July 2025), Fewer New Miles: Strategic Industries Held Back by Slow Pace of Transmission including its addendum incorporating FERC's April 2025 revisions: new high-voltage (345 kV+) transmission construction fell from an average of 1,781 miles/year (2010–2014) to 536 miles/year (2020–2024). On transmission spending: Edison Electric Institute (updated September 2025), EEI Industry Capital Expenditures 2015–2029: projected transmission capital expenditure of $35.9 billion in 2024 and $37.6 billion in 2025.

[35] U.S. Department of Energy (December 2023), National Transmission Needs Study: median within-region transmission need of 54,500 GW-miles by 2035, a 64% increase over today's system.

[36] IEA (updated June 2025), Ontario Feed-in Tariff Programme. "FIT payments can range from CAD 10.3 cents per kilowatt-hour (CAD c/kWh) for landfill gas projects larger than 10 MW to 80.2 CAD ¢/kWh for residential solar rooftop projects 10 kW or smaller." 80.2¢ CAD × 1.445 (Bank of Canada cumulative CAD inflation, 2009→2026) = 115.9¢ CAD (2026 terms) × ~0.71 USD/CAD = 82 ¢ USD.

[37] Streich (June 2011), Green Energy and Green Economy Act, 2009: A 'FIT'-ing Policy for North America? *Houston Journal of International Law*, Vol. 33, No. 2

[38] Ontario (October 2018), O. Reg. 359/09; Green Energy Repeal Act (Bill 34), effective January 1, 2019.

[39] Magne (April 2020), New York Passes Sweeping Renewable Energy Siting Reform. *Young/Sommer LLC*; New York ORES and 94-c established (2020).

[40] Terra Praxis (August 2023), Risks to the Energy Transition

[41] Eisen & Jackson (December 2015), Auditor general's report latest evidence Ontarians are overpaying for power. The Toronto Star

[42] Calculated from Office of the Auditor General of Ontario (2015), 2015 Annual Report, Chapter 3 (Electricity Power System Planning): Figure 4 (2014 generation cost = 62% of total all-in electricity service cost); Figure 7 (annual grid-connected consumption, 2006–2014); Figure 8 (annual all-in commodity price, 2006–2014). These imply a cumulative commodity cost of approximately $88 billion over 2006–2014; extrapolating the 62% generation share across the period implies cumulative all-in electricity spending of approximately $141 billion, against which the $37 billion overpayment is approximately 26%.

[43] Morrow (December 2015), Ontarians paid $37-billion above market for electricity over eight years, Auditor-General's report says. *Globe & Mail*

[44] The Canadian Press (July 2018), Ontario government cancels 758 renewable energy contracts, says it will save millions. *CBC*

[45] Citizen Action of New York et al. v. New York State Department of Environmental Conservation, Index No. 903160-25 (N.Y. Sup. Ct., Albany County, October 24, 2025); case record and decision documents at the Sabin Center for Climate Change Law, Climate Case Chart. DEC filed a notice of appeal on November 25, 2025 (App. Div., Third Dep't, CV-25-1957), which triggered an automatic stay of the February 6, 2026 deadline; New York's May 2026 budget amendments to the CLCPA subsequently reset the statutory promulgation deadline to December 31, 2028. See Russo et al (May 2026), New York Budget Amends the State's Climate Leadership and Community Protection Act. *GreenbergTraurig*

[46] FERC, as quoted in The Quad Report (2025), Getting Pumped: Hydro Storage Promises and Problems: "most of the existing pumped hydro projects were developed in the 1960s to the 1980s 'to complement operation of large, baseload coal and nuclear power plants by balancing electricity load and demand on the transmission grid.'" Wikipedia, List of pumped-storage hydroelectric power stations.

[47] Ontario (n.d.), The End of Coal

[48] U.S. Department of Energy (September 2024), Pathways to Commercial Liftoff: Advanced Nuclear

[49] Options Paper, Section 2.3 ("Benefits and Costs of the Backbone"), p. 8: two nuclear-deployment scenarios (low end: 2.2 GW by 2040 / 4.8 GW by 2050, net system benefits of $28.1 billion by 2040 and $47.2 billion by 2050, NPV; high end: 3.3 GW by 2040 / 5.6 GW by 2050, $31.1 billion and $54.2 billion, respectively), relative to a baseline of decarbonizing the grid without nuclear. Public support cost and pipeline sensitivity figures: Appendix C ("Cost Analysis—Inputs and Methodology"), Table C-1 (overnight capital costs, hurdle rates) and Appendix D ("Cost Analysis—Results")

[50] NYISO (2026), 2026 Power Trends "An aging generation fleet" (p. 6): "a significant share of this fleet is now more than 50 years old, with some units approaching or exceeding the end of the typical economic and/or mechanical life of similar generation facilities across the nation"; reliability-risk outlook (p. 22): "New York's generation fleet is among the oldest in the country," with many fossil units providing essential reliability services "nearing retirement"; Figure 13 (p. 34): units 50 or more years old produced 12,815 GWh in 2025, about 10% of in-state energy production; p. 34 also reports power producers "considering repowering select aging fossil-fuel generators in New York City and Long Island," with a combined capacity of approximately 3,500 MW.

[51] Terra Praxis (May 2026), REPOWER Germany: The Case for Repowering Coal and Nuclear Sites with Advanced Nuclear. *A Discussion Paper for the 6th REPOWER Retreat, Munich*

[52] NYSERDA (September 2025), Zero by 40 Technoeconomic Assessment, Table 22 and Figure 39 (p. 161) and Table 20 (p. 153). *Prepared by the Electric Power Research Institute.* EPRI puts a large reactor's plant footprint at 100–400 acres per unit, so 5 GW as four or five large units occupies 400–2,000 acres in total, or 200–800 acres per site with two units each. New York's operating plants confirm the scale: Nine Mile Point and FitzPatrick share 900 acres for 2,832 MW_e across three units, and Ginna occupies 426 acres for 576 MW_e. For solar, EPRI's 200 MWh per acre per year (against 57,000 for nuclear) means the 40.3 TWh that 5 GW of nuclear generates at a 92% capacity factor would need about 200,000 acres of panels (40,300,000 ÷ 200).

[53] Seneviratne (2026), Nuclear heat and power for industrial decarbonization, in Foss, A. and Stauff, N. (eds.), New Directions in Nuclear Energy: Innovation and Opportunities in Fission and Fusion for Global Decarbonization, *Woodhead Publishing*

[54] The Royal Society (October 2020), Nuclear cogeneration: civil nuclear energy in a low-carbon future

[55] LucidCatalyst (2020), Missing Link to a Livable Climate: How Hydrogen-Enabled Synthetic Fuels Can Help Deliver the Paris Goals

[56] Ibid.

[57] Bipartisan Policy Center, Can Advanced Nuclear Repower Coal Country? (March 2023) (77% of coal-plant positions transferable to a nuclear plant with no new licensing requirements; the remaining 23%, including operators, senior managers, and technicians, require licensing or extensive retraining).

[58] U.S. Department of Energy (September 2022), Investigating Benefits and Challenges of Converting Retiring Coal Plants into Nuclear Plants *Idaho National Laboratory et al* (case study replacing a composite 1,200 MW_e coal plant with 924 MW_e of nuclear capacity: regional economic activity increases by as much as $275 million, including more than 650 net new permanent jobs)

[59] LucidCatalyst (November 2025), A New Nuclear World: How Small Modular Reactors Can Power Industry, Table 3 (project supply scenarios: delivery model, cost, delivery time and deployment rate) and Section 4.5, which describes the four supply scenarios as "not sequential stages but parallel development pathways that could emerge simultaneously".

[60] LucidCatalyst (November 2025), A New Nuclear World: How Small Modular Reactors Can Power Industry

[61] Wald (January 2025), Resurrecting Three Mile Island *Nuclear Newswire*

[62] Howland (June 2026), Constellation's Three Mile Island nuclear restart gets boost with FERC waiver. *Utility Dive*

[63] Reuters (March 2026), Constellation exec says grid operator told company Three Mile Island can't connect until 2031 (quoting David Dardis, Constellation's chief external affairs and growth officer, at CERAWeek).

[64] EPRI (2024), Advanced Nuclear Technology: Single Site Evaluation Guide--Preliminary Assessment of a Predefined Site for Deployment of a New Nuclear Energy Facility

[65] Terra Praxis (July 2026), "America's Coal Fleet, Ready to Repower" (Phoenix Fact Sheet). *Available upon request.*

[66] Terra Praxis (November 2024), Terra Praxis Offers AI for Licensing Capabilities

[67] Microsoft (March 2026), Aalo Atomics sees 92% cut in permit time with Azure, saving $80M yearly

[68] NNY360 (May 2026), Nuclear operator will seek site approval for new plant at Oswego County's Nine Mile Point. Cited as a real New York cost baseline for nuclear licensing preparation; the AI for Licensing copilot has not been applied to this specific Nine Mile Point filing.

[69] New York Power Authority (June 2025), Governor Hochul Directs New York Power Authority to Develop a Zero-Emission Advanced Nuclear Energy Technology Power Plant (candidate locations assessed on public safety, strength of community support, compatibility with existing infrastructure, skilled labor, and land availability); New York Power Authority Issues First Solicitations for Advanced Nuclear Project (October 2025) (RFI site-suitability factors: size, water access, and protection from external hazards).

[70] Options Paper, Appendix C, Table C-3, Section 3

[71] Options Paper, Appendix D

[72] Team Pennsylvania (June 1, 2026), Pennsylvania Nuclear Energy Roadmap p. 50.

[73] Options Paper, Appendix D

[74] The Options Paper explicitly benchmarks that $132/MWh figure against a real transaction: the Microsoft–Constellation Three Mile Island restart power purchase agreement, priced at roughly $115/MWh. Further combinations the Options Paper models (a capped ANZEC price, state equity, and construction grants together) bring the large-reactor brownfield figure as low as $97–100/MWh.

[75] Options Paper, Appendix C, Table C-1 and Appendix D, Table D-3 (federal ITC and debt support, private equity at the 35% first-unit hurdle). Also note SMR (250 MW class) overnight capital cost: $18.7/W greenfield, $17.3/W brownfield. With the Paper's Base Case support (ITC, federal loan guarantee, State overrun guarantee, ANZECs) the price at commercial operation falls to $18.7 billion greenfield and $15.4 billion brownfield, multiples of about 1.5× and 1.35×.

[76] NYISO (2026), 2026 Power Trends, Figure 12 (Historical Natural Gas and Wholesale Electricity Prices, 2000–2025), p. 32: average annual wholesale electricity price of $74.40/MWh in 2025, with natural gas at $4.64/MMBtu. This is an energy-only spot price; it does not include capacity, ancillary services, or other costs of a firm, contracted product.

[77] Compounding is convex: a dollar of 35% equity spent in year one of a twelve-year build must grow to roughly $32 by commercial operation; a dollar of the Paper's pre-FID bridge debt, refinanced into 5% federal debt at FID, grows to about $1.80. Compounding each kind of money at its own rate, as NYSERDA correctly models, a year-one dollar split half and half costs about $17.

[78] Two-tranche construction-carry model matching the Options Paper's financing methodology, on its own financing terms (Appendix C): FID at the start of year 3; before FID, 50% bridge debt at 7.5%, refinanced at FID, and 50% equity at the first-unit hurdle (35% for the large reactor, 40% for the SMR); after FID, 80% DOE-guaranteed debt at 5% and 20% equity at the rate shown on each curve. Each tranche is compounded separately from spend date to commercial operation across the Paper's Beta-shaped spend profile compressed to the build length, with nominal cost escalation of 2.33% per year. The two marked points are the Section 7 scenarios: the Paper's brownfield case (ten years, 35%) at 1.78 times overnight cost and the front-loaded alternative (eight years, 17.5% from FID) at 1.37 times. Financing structure and equity-hurdle ladder per Options Paper's Table C-3; anchor costs and durations: Tables D-1–D-3. NYSERDA's own Table D-3 reports $19.4 billion for the same ten-year brownfield case, shown in Table 3; the difference reflects the simplified two-tranche model used here.

[79] LucidCatalyst (September 2020), The ETI Nuclear Cost Drivers Project: Full Technical Report

[80] OECD Nuclear Energy Agency (2015), Nuclear New Build: Insights into Financing and Project Management, NEA No. 7195, Chapter III.5.2, pp. 198–207, drawing on IAEA (1998) and IAEA-TECDOC-1390 (2004): 51.5 months from inspection of foundation to commercial operation, about 48 months net of first-of-a-kind testing. First concrete to first criticality, 37 months: Kim and Keppler, NEA (March 2014), The ABWR Project at Shimane-3, Japan. Chart: construction-start and first-criticality dates for the four ABWRs from the World Nuclear Association reactor database; Barakah 1, first concrete July 2012 to ENEC's construction-complete announcement of March 2018, with commercial operation in April 2021 after operator licensing, World Nuclear Association (updated July 2026), Nuclear Power in the United Arab Emirates; Vogtle 3, first concrete to fuel load, endnote 89; Olkiluoto 3, first concrete to fuel load, World Nuclear Association (updated August 2026), Nuclear Power in Finland. Flamanville 3, first concrete December 2007 to completion of fuel loading on 22 May 2024, World Nuclear Association, Nuclear Power in France, and World Nuclear News (May 2024), Fuel loading completed at France's Flamanville 3 EPR. Commercial operation is excluded throughout, so that post-construction operator licensing — nearly three years at Barakah 1 — is not counted as construction time; on the conventional definition, which runs to the start of commercial operation, Kashiwazaki-Kariwa 6 took 51.5 months from inspection of foundation. Kim and Keppler give the 37 months to first criticality with dates at p. 12 and to fuel load in the summary at p. 17; the dated figures are used here.

[81] OECD Nuclear Energy Agency (2020) Unlocking Reductions in the Construction Costs of Nuclear: A Practical Guide for Stakeholders

[82] LucidCatalyst (September 2020), The ETI Nuclear Cost Drivers Project: Full Technical Report, Sections 6.5.4 and 6.6.1 (sequenced programs with the same delivery teams; government support contingent on a completed design, 4D construction planning and constructability review) and Summary Report. The remarks attributed to a GE Hitachi engineer and to Barakah's chief executive are personal communications to Eric Ingersoll during and after the project's interview program in Japan, the United States and the United Arab Emirates.

[83] Calculated using Options Paper's financing terms (Appendix C): overnight cost $11.4 billion for the first brownfield large reactor (Table C-1); FID at the start of year 3 (p. C-12); before FID, 50% bridge debt at 7.5%, refinanced at FID, and 50% private equity; after FID, 80% DOE-guaranteed debt at 5% and 20% private equity; the Paper's S-curve compressed to the build length; 2.33% escalation. A year-one dollar of pre-FID spending reaches commercial operation at about $2.50 on the project's own terms and $1.40 at the State's 5%, giving break-even additional budgets of $1.8 billion and $3.3 billion. If the pre-FID equity kept its 35% return to commercial operation rather than being re-rated at FID, the project-financed ceiling would fall to about $0.9 billion; the State-funded ceiling is little changed.

[84] LucidCatalyst Nuclear Cost Drivers. Barakah (Units 1–4) (Partially Complete). p. 86

[85] Blue Energy (July 2026), Blue Energy Receives Strategic Investment from Constellation to Accelerate Commercialization of Novel Shipyard Manufacturing and Project Financing Model for New Nuclear.

[86] Patel (August 2026), Oklo's Groves Becomes Fifth DOE Pilot Reactor to Reach Criticality, First on Private Land *POWER Magazine* and Crownhart (July 2026) Four nuclear reactors hit a big milestone in the US *MIT Technology Review*. The DOE Reactor Pilot Program enabled criticality demonstrations (zero-power rather than power operations): Antares Nuclear's Mark-0 (Idaho National Laboratory, June 4), Valar Atomics' Ward 250 (San Rafael Energy Lab, Utah, June 18), Deployable Energy's Unity (Idaho National Laboratory, June 30), Aalo Atomics' Critical Test Reactor (Idaho National Laboratory, July 4), Oklo's Groves Isotope Test Reactor (Lockhart, Texas, August 5). Aalo is concurrently fitting out an assembly-line reactor factory and targets first electricity at a co-located data center in 2027.

[87] Shaw, a minority owner of Westinghouse, was acquired by CB&I, which Westinghouse itself later acquired.

[88] LucidCatalyst Nuclear Cost Drivers lists "litigation between project participants" as a named indicator within the Project Development and Governance cost driver; Vogtle case study (Westinghouse's triple role; consortium ownership churn among Westinghouse, Shaw/Stone & Webster, and CB&I as costs escalated; PSC expert testimony that the fixed-price EPC contract left the owner "not a great deal of management [it could] actually do" without forfeiting contract protections; post-2017-bankruptcy recovery under Bechtel on a cost-plus, risk-sharing contract); Barakah case study ("clear responsibility and authority under the prime contractor"), pp. 89–92.

[89] World Nuclear Association, Nuclear Power in the United Arab Emirates (country profile); ENEC, Prime Contractor. ENEC's December 2009 award followed a year-long evaluation, by a team of 75 international experts, of three competing consortia led by KEPCO, AREVA, and GE-Hitachi, resulting in a $20.4 billion prime contract for design, construction, and commissioning of four APR1400 units.

[90] LucidCatalyst (July 2020), Drivers of Cost and Risk in Nuclear New Build Reflecting International Experience, MEH Alliance case study: Altrad, Balfour Beatty Bailey, Cavendish Nuclear, and Doosan Babcock brought into a single incentive-aligned entity for Hinkley Point C's mechanical, electrical, and HVAC phase, following practice demonstrated at Taishan.

[91] Ibid. Hinkley Point C series-effect figures and the delay-risk finding are from this report.

[92] U.S. Energy Information Administration (August 2023), First new U.S. nuclear reactor since 2016 is now in operation, and (May 2024), Plant Vogtle Unit 4 begins commercial operation: the project was "originally expected to cost $14 billion and begin commercial operation in 2016 (Vogtle 3) and 2017 (Vogtle 4)"; Georgia Power now estimates the total cost of the project at more than $30 billion. Unit 3 entered commercial operation in July 2023 and Unit 4 in April 2024, each about seven years after its original date.

[93] Satymov et al. (September 2025), Who will foot the bill? The opportunity cost of prioritising nuclear power over renewable energy for the case of Finland, Energy, vol. 337, art. 138630: Olkiluoto 3 "was operational 13 years late", and its "final capital expenditure (CAPEX) of 11 b€ equals a cost overrun of 266% over the initial cost estimate of 3 b€." The €11 billion combines TVO's own investment of around €5.5 billion with around €5.5 billion of losses borne by the Areva-Siemens supplier consortium under the 2003 fixed-price turnkey contract: World Nuclear Industry Status Report (March 2022), Europe's First EPR: 13 Years Behind Schedule, Olkiluoto-3 in Finland Starts Up.

[94] LucidCatalyst (July 2020), Drivers of Cost and Risk in Nuclear New Build Reflecting International Experience. Hinkley Point C series-effect

[95] EDF (January 2024), Hinkley Point C Update: £31–35 billion in 2015 prices, first power 2029–2031; superseded by EDF (February 2026), 2025 Annual Results: completion cost estimate £35 billion in 2015 sterling (about £48 billion in current prices, as reported by Construction Management, 23 February 2026), Unit 1 start-up moved to 2030 owing to electromechanical work. Original 2016 estimate £18 billion (2015 prices), first power 2025. Sizewell C replication and the roughly 20% lower expected build cost: UK Government, Sizewell C final investment decision announcement (July 2025), and World Nuclear Association (updated August 2026), Nuclear Power in the United Kingdom.

[96] Vogtle construction equity earned Georgia Power's regulated return, authorized at 10.95% and later reduced to 10.0% by the Georgia Public Service Commission, and was collected as current cash from ratepayers during construction under Georgia's Nuclear Construction Cost Recovery tariff rather than compounding against the project. Georgia Public Service Commission, Docket 29849 (Seventeenth Vogtle Construction Monitoring report, order January 11, 2018); S&P Global Market Intelligence (October 2016), Vogtle nuclear settlement increases cost recovery for Georgia Power, cuts ROE.

[97] Options Paper, Section 4.3 (Ownership Structures), p. 36: the CWIP variant, under which the Commission would let a utility pass construction-period payments to ratepayers as incurred. Section 4.4 (Construction Grants), p. 38: the PRDC variant, which the Paper describes as "similar in nature" to CWIP. Appendix D (Cost Analysis – Results) finds PRDC does not offer a dollar-for-dollar efficiency advantage over a standard lump-sum grant; comparison drawn here against the no-support, full-compounding case, not against grants.

[98] Options Paper, Appendix A, Figures A-1 and A-2 (Jobs by Industry): manufacturing accounts for 15% of construction-phase jobs for the LLWR and 19% for the lwSMR, alongside separate professional-services, other-supply-chain, and induced-jobs categories.

[99] Options Paper, Appendix A, §A.3 (Additional Supply Chain Opportunities): identifies existing New York capacity for Tier 2/3 components including nuclear-grade cement and sand, industrial pumps and valves, heat exchangers, nuclear-qualified electrical and measurement systems, and rebar steel, and flags reactor pressure vessels, steam generators, and large forgings as deeper, currently globally-sourced investment opportunities. The appendix notes onshoring could also serve an export market for other states.

[100] Albany County (February 2026), Local Law "H" of 2025, amending Chapter 135 of the Albany County Code to fund the development of parts and components of Advanced Nuclear Technologies as a qualifying "green business" activity, reported by Nuclear New York.

ABOUT TERRA PRAXIS

Terra Praxis is a global nonprofit organization committed to universal access to affordable, reliable, and clean energy that empowers people and protects nature. Powered by philanthropy, we innovate and accelerate scalable, equitable solutions to decarbonize the largest sources of global emissions (the difficult-to-decarbonize sectors of coal-for-power, industrial heat, aviation, and heavy transport).

The Terra Praxis REPOWER Consortium is executing an integrated strategy to deploy fast, low-cost, and repeatable solutions for repurposing existing coal plants and other energy intensive infrastructure (e.g., data centers, steel, cement, aviation, shipping) to continue operating with emissions-free power, heat, and steam supplied by mass-manufactured advanced nuclear.

REPOWER leverages existing sites, transmission, industry knowledge, workforces, capital, and supply chains to supply clean, reliable, and affordable energy and produce emissions-free fuel. It has the potential to eliminate one-third of global carbon emissions while ensuring continuity for communities reliant on power plants for energy, jobs, tax revenue, and continued economic growth.

Terra Praxis offers two key tools to countries and states interested in meeting both electricity and industrial energy demand at scale, cost, and speed, while decarbonizing and expanding its industrial economy. The Gen AI for Licensing copilot, developed with Microsoft, can cut the human-hours required to prepare nuclear licensing applications by as much as 90%. Its REPOWER Automated Configuration Technology (ACT) platform produces in weeks the feasibility work a conventional study takes twelve to eighteen months to deliver.

Learn more at TerraPraxis.org or contact info@TerraPraxis.org.

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