Economic Analysis of First- and Nth-of-a-Kind Micromodular Reactors Co-Sited with Nuclear Fuel Cycle Facilities in the United States

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Abstract: Nuclear fuel cycle facilities, especially uranium enrichment plants, are highly electricity-intensive and rely on an uninterrupted power supply, making them vulnerable to electricity cost fluctuations and grid stability. Micromodular reactors, with electrical outputs of 5–25 MWe, offer an option for dedicated on-site power generation within existing nuclear security perimeters, yet no systematic cross-vendor comparison of first-of-a-kind and Nth-of-a-kind cost trajectories exists, nor has financial viability been assessed at a specific U.S. enrichment facility. This study develops first- and Nth-of-a-kind cost trajectories for seven U.S.-relevant micromodular reactor vendors across four technology families, i.e., liquid-metal fast reactors, heat-pipe microreactors, gas-cooled reactors, and light-water reactors, and evaluates the 50-year economic viability of co-siting at Centrus Energy Corp.'s American Centrifuge Plant under two demand scenarios. Capital costs were estimated using a standardized account-level methodology; Nth-of-a-kind trajectories follow learning curve modeling with category-specific learning rates. A 50-year levelized cost of electricity and net present value analysis was conducted under three investment tax credit levels (0%, 30%, and 50%), incorporating escalating operations and maintenance costs (3%/year), nuclear fuel cost escalation (2.5%/year), and an increasing grid outage exposure (2%/year). Non-light-water designs average 57% lower first-of-a-kind capital costs than light-water alternatives, and Nth-of-a-kind costs decline by 44–64% by the 100th unit. Without tax incentives, micromodular reactor electricity costs exceed the grid baseline; a 30% investment tax credit achieves grid parity, and a 50% credit yields costs roughly 32% below grid. Under a 30% investment tax credit, the net present value turns positive at the 10th unit, marking the transition from government-supported to commercially self-sustaining deployment, with a 50-year net present value advantage of $1.75B–$2.65B over grid-only supply. These results support micromodular reactor co-siting as commercially viable within a decade, with investment tax credit support primarily needed at first-of-a-kind deployment.

1. INTRODUCTION

At the Centrus Energy Corp. American Centrifuge Plant (ACP) in Piketon, Ohio, the only domestically owned uranium enrichment facility in the United States, an unplanned grid outage is estimated to cost between $81,000 to $163,000 per hour, depending on production scale (see Section 2.2). With an average grid outage exposure of approximately 11 hours per year (i.e., due to extreme weather events, grid aging, and grid overload), the expected annual production losses attributable to grid unreliability alone range from $897,000 to $1.79 million, respectively. Given this intermittence and financial impact, preventive actions are recommended to establish redundant or alternative power supplies, such as diesel generators, to mitigate potential losses. But the outage exposure is not the only factor. Beyond outage costs, the ACP and facilities of its class are exposed to industrial electricity price volatility, future carbon pricing schemes that could materially alter operating economics, and energy security considerations arising from a shared regional grid for operations that are, by any reasonable definition, part of U.S. nuclear security infrastructure. The strategic and economic implications of the grid dependency of nuclear fuel cycle (NFC) facilities have been examined by this study within the broader framework of nuclear energy's role in a carbon-constrained energy transition.

Micromodular reactors (MMRs) are compact nuclear systems (5-25 MWe, 300-600°C coolant) that offer dedicated on-site power and steam for NFC facilities. Their output matches enrichment plant demands. Designed for deployment within nuclear security perimeters without full site licensing, MMRs have passive safety and small radiological source terms, supporting co-siting with licensed operations [1–3]. Nuclear microreactors and compact nuclear batteries have been evaluated for similar applications in offshore and remote settings [4, 5], setting a precedent for the NFC co-siting scenario in this study. On the regulatory side, three Tier 1 vendors have significant U.S. NRC engagement records as of 2025 (seven vendors across three tiers are analyzed in this study) [6–8]. However, despite this progress, two analytical questions are not fully understood in the open literature.

First, no systematic, cross-vendor comparison of first-of-a-kind (FOAK) and Nth-of-a-kind (NOAK) capital costs exists for U.S. MMR vendors using a standardized, account-level methodology. Prior studies reviewed advanced reactor costs at higher levels [9, 10], but not vendor-specific, account-level profiles across technologies. Second, a comprehensive 50-year financial viability analysis for MMR co-siting at an NFC facility—considering demand, financing, and policy—remains lacking. Earlier small modular reactor studies addressed regulatory fees [11] and incremental deployment [12], but not at the facility-demand scale for NFC co-siting.

This paper aims to address both questions. The specific contributions of this study are:

1. FOAK capital cost estimates for seven U.S. MMR vendors across four technology families, using the MOUSE methodology (INL-RPT-25-87273 [13]) and 82 cost accounts;
2. Component-disaggregated NOAK cost trajectories via Wright's Law learning curves, with learning rates by component category and NRC licensing tier;
3. Quantification of NRC regulatory tier cost impacts under the three-tier framework for advanced non-LWR designs;
4. 50-year LCOE and NPV analysis for Centrus demand scenarios (21.7 MWe and 37.1 MWe), at an 8% real discount rate under three ITC levels (0%, 30%, 50%), as detailed in Section 2.2; and
5. A framework showing the fleet unit number at which MMR co-siting at a U.S. enrichment facility becomes commercially viable without federal tax support.

Section 2 reviews the MMR technology landscape, Centrus facility, and FOAK/NOAK cost framework. Section 3 outlines the MOUSE methodology, learning curve, and economic evaluation. Section 4 presents cost results, Centrus LCOE/NPV analysis, and discusses technology choices and policy. Section 5 summarizes conclusions and future work.

2. BACKGROUND

2.1. MMR Technology Landscape

As of 2024, the U.S. MMR nuclear market comprises four major technology families for future deployments. This analysis introduces a three-tier regulatory system based on each vendor's engagement with the U.S. NRC and their maturity. Tier assignments are derived from a review of submissions in the NRC's Agencywide Documents Access and Management System (ADAMS) database [14], evaluated across three dimensions: document volume, licensing activity duration, and technical topic coverage across 13 regulatory categories.

Tier 1: The top three vendors with significant U.S. NRC engagement as of 2025 are Westinghouse (213 documents; 2,214 days) [7], Oklo (188 documents; 1,262 days) [6], and NANO Nuclear (170 documents; 1,490 days) [15]. Their documentation includes reactor design, safety, digital I&C, security, siting, and emergency planning. Tier 1 vendors are expected to achieve a regulatory cost reduction of $4.7 million per unit licensed ahead compared to the $30–$32 million Tier 3 full licensing cost, derived in [13] by applying U.S. NRC 10 CFR Part 170 [16] billing rates to projected review-hour reductions attributable to prior regulatory engagement. *Tier 2*: BWXT (48 documents; 872 days) [8] and X-Energy (49 documents; 625 days) [17] have engaged actively with the NRC, resulting in approximately $2.5 million cost reduction per unit licensed ahead by the same methodology [13]. *Tier 3*: Last Energy (12 documents; 139 days) [18] and Hadron Energy (7 documents; 82 days) [19] are in the early stages of NRC engagement, with limited coverage and no cost reductions established by the same methodology [13]. These tier assignments influence the modified MOUSE framework (see Section 3.1), affecting regulatory learning rates and licensing costs. Table 1 outlines the MMR technology summary for the seven vendors analyzed.

Table 1. Vendor Technology Summary

Vendor	Tech	Power (MWe)	Outlet Temp. (°C)	Fuel	Reg. Tier
Oklo	LMFR	15–25	~550	Metallic U	Tier 1
Westinghouse	HPMR	5	~600	TRISO	Tier 1
NANO Nuclear	GCMR	3.5–15	~660	TRISO	Tier 1
BWXT	GCMR	12	~700	TRISO	Tier 2
X-Energy	GCMR	10	~750	TRISO	Tier 2
Last Energy	PWR	20	~325	UO_2	Tier 3
Hadron Energy	PWR	10	~325	UO_2	Tier 3

Liquid-metal fast reactors (LMFR), like Oklo Inc.'s Aurora Powerhouse (15-25 MWe), use metallic uranium fuel and sodium cooling at about 550°C. *Heat-pipe microreactors (HPMR)*, such as the Westinghouse eVinci (5 MWe), utilize passive sodium heat-pipe cooling for factory assembly and near-autonomous operation. *Gas-cooled modular reactors (GCMR)*, including Nano Nuclear KRONOS MMR (3.5-5 MWe), BWXT BANR (12 MWe), and X-Energy Xe-100 (20 MWe), use TRISO fuel and helium coolant at 700-750°C[1]. Light-water PWR-based designs, such as Last Energy PWR20 (20 MWe) and Hadron Energy microreactor (10 MWe), operate at around 325°C with UO_2 fuel, following LWR technology. Key differentiators among these reactors include coolant outlet temperature, fabrication fraction, and regulatory tier, influencing energy application fit and costs, as outlined in Section 3.

2.2. Centrus Energy Corp. as Case Study

This paper uses the Centrus Energy Corp. American Centrifuge Plant (ACP) in Piketon, Ohio, as a case study due to its unique position in the U.S. enrichment landscape, its well-characterized electrical demand, and existing nuclear infrastructure at the Portsmouth brownfield site. The ACP is currently the only domestically owned uranium enrichment facility in the U.S. with a U.S. NRC Special Nuclear Material license, SNM-2011 [20]. It operates gas centrifuge cascades with a continuous and uninterruptible electrical load. Cascade shutdowns necessitate controlled restarts, which prolong production loss significantly. At a licensed production capacity of 3.8 million SWU per year (requiring an estimated 21.7 MWe[2]), the cost of an unplanned grid outage is estimated at $81,000 per hour[3]. The ACP has also assessed potential expansion to 7.6 million SWU per year (equivalent to 37.1 MWe), with an estimated outage cost of $163,000 per hour[3]. With a historical average grid outage exposure of 11 hours per year [23], the expected annual production impact ranges from $897,000 to $1.79 million across the two scenarios, assuming no mitigative actions are taken. The study estimates the ACP purchases electricity at a baseline rate of $86.3/MWh from the regional grid[4].

Both aforementioned demand scenarios sit within the typical output range of MMR designs currently under development in the U.S. (discussed in Section 2.1), which means ACP is a direct co-siting candidate. The existing Portsmouth brownfield regulations, such as the nuclear security perimeter, U.S. NRC-licensed controlled area, nuclear-qualified workforce, and active emergency planning infrastructure at the ACP, constitute meaningful co-siting infrastructure that would reduce the regulatory burden relative to greenfield deployment, which represents an advantage treated qualitatively in this study.

[1] TRISO retains fission products up to 1,600°C, while helium's inertness allows for complete isolation.
[2] It is based on an advanced gas centrifuge consumption rate of 50 kWh/SWU [21].
[3] It was assumed a marginal value of $188/SWU, according to [22].
[4] This study considered the industrial electricity rates from Oct. 2024 to Oct. 2025 in Southern Ohio, according to [24].

The \$81,000–\$163,000 per-hour figure accounts only for foregone SWU production; it underestimates the true impact because Centrus AC-100M super-critical rotors require continuous drive-frequency control, and a power loss without active damping can cause irreversible cascade structural failure, as observed in 2011 [25]. As the sole domestic source of HALEU[5], any ACP outage has supply-chain consequences beyond Centrus's direct revenue loss [26], reinforcing the case for the economic analysis in Sections 3–4.

2.3. FOAK/NOAK Concepts and Government-to-Private Transition

A first-of-a-kind (FOAK) unit is the initial commercial deployment of a new reactor design, where development costs and regulatory compliance must be absorbed without production learning. An Nth-of-a-kind (NOAK) unit achieves 90%[6] of the cost reduction predicted by Wright's Law, whereby unit costs decrease by a constant fraction with each production doubling [27]. This model indicates that factory-fabricated designs (LMFR, HPMR, GCMR) have a lower baseline cost than conventional site-built configurations like PWR-based designs [28] [29].

The transition framework in this study incorporates three federal instruments to subsidize advanced nuclear projects: 1) Investment Tax Credit (ITC) at 30% and a proposed 50% under the Inflation Reduction Act (IRA) Section 48C [30]; 2) Production Tax Credit (PTC) of \$15/MWh for qualifying clean electricity generators [30]; and 3) U.S. Department of Energy (DOE) Loan Programs Office (LPO) financing at reduced interest rates of 2.5-5.5% [31]. The transition threshold is defined as the fleet unit number where the 50-year NPV of MMR co-siting becomes positive without ITC support, paralleling the U.S. LWR commercialization trajectory of the 1960s–70s, where government-backed financing bridged the FOAK cost gap until private deployment was viable [11, 29, 32].

3. METHODOLOGY

3.1. MOUSE Framework and Vendor Cost Scaling

The capital cost estimates for all seven vendors rely on the economic portion of the MOUSE methodology developed by the Idaho National Laboratory [13]. This methodology categorizes reactor costs into 82 accounts spread across 15 categories: 10 for direct construction and system costs and 5 for indirect project costs. Direct categories cover physical plant systems, while indirect costs include engineering, procurement, construction management, startup, and owner's expenses — as shown in Table 2. Costs are scaled from four technology-specific reference designs: a Liquid Metal Thermal Micro Reactor (LTMR) at 7 MWe (\$152.7M), a Gas Cooled Micro Reactor (GCMR) at 6 MWe (\$160.9M), and a Heat Pipe Micro Reactor (HPMR) at 2.52 MWe (\$135.7M). The Pressurized Water Reactor (PWR) reference, at 1,144 MWe, is based on a cost of \$4,655/kWe in 2024 dollars, inflated from \$4,155/kWe in 2019 using the cost escalation assumption from [13]. Vendor-specific costs are derived by scaling from the closest reference design using the power-law relationship in Eq. 1.

$$C_{\text{vendor}} = C_{\text{ref}} \times \left(\frac{P_{\text{vendor}}}{P_{\text{ref}}} \right)^n \tag{1}$$

where C_{vendor} and C_{ref} are total capital costs in millions of 2024 U.S. dollars, P_{vendor} and P_{ref} are thermal power outputs in MWt, and the scaling exponent $n = 0.60$ for designs below 30 MWt and $n = 0.51$ for designs in the 30–300 MWt range [13]. These exponents are engineering calibrations in MOUSE, not empirical values from historical microreactor data, which is unavailable at commercial scale; the ±20% FOAK capital cost sensitivity in Table 6 reflects this uncertainty. As discussed in Table 2, a regulatory maturity and engagement cost adjustment is applied to the U.S. NRC licensing tier categories: Tier 1 designs (Westinghouse, Oklo,

[5] High-Assay Low-Enriched Uranium (HALEU) is a type of nuclear fuel that has an enrichment level of 5–20% uranium-235, which is considerably higher than the 3–5% enrichment typically found in conventional light water reactors [20].

[6] The 90% threshold is an estimation used in the nuclear learning curve literature as a practical criterion for commercial maturity.

NANO Nuclear) realize an estimated \$4.7 million per-unit licensed ahead saving relative to Tier 3 baseline licensing costs; Tier 2 designs (BWXT, X-Energy) realize \$2.5 million per unit licensed ahead; Tier 3 designs (Last Energy, Hadron) receive no reduction [13, 14].

Table 2. MOUSE cost account structure: cost categories, scaling parameters, reference reactor values, and component-level learning rates. Adapted from [13].

Cost Category	Account No.§	Scaling Parameter	Reference Value	Learn. Rate
Site preparation & land	11–12, 211	Floor area $(m^2)^{0.70}$	Site-specific	8%
Reactor structures	21 (211-215)	Thermal power $(MWt)^{0.60}$	Tech.-family ref.‡	18%
Primary reactor systems	22 (221-228)	Thermal power $(MWt)^{0.60}$	LTMR \$152.7M; GCMR \$160.9M; HPMR \$135.7M	23–24%
Power conversion	23 (232, 236)	Electric power $(MWe)^{0.60}$	Tech.-family ref.‡	18%
I&C	227, 236	Electric power $(MWe)^{0.51}$	Tech.-family ref.‡	8%
Electric & auxiliary systems	24 (241-246)	Electric power $(MWe)^{0.60}$	Tech.-family ref.‡	8%
Fuel & radiation waste	25 (241-246)	Thermal power $(MWt)^{0.51}$	Tech.-family ref.‡	18–23%
Engineering & procurement	31-36	% of direct cost	15% + 12%	8%
Licensing & regulation	13, 73	U.S. NRC tier-based	Tier 1: -\$4.7M; Tier 2: -\$2.5M	8–15%†
Owner's & contingency	40-41, 60-62	% of total cost	7% + 10–15%	0%

†Tier 1 licensing savings relative to Tier 3 full regulatory cost of \$30–\$32M per unit.
‡"Tech.-family ref." indicates that the reference value is scaled from the applicable MOUSE technology-family reference reactor (Section 3.1).
§The account numbering system adheres to the MOUSE hierarchical cost account structure [13]. However, it should be noted that not all accounts were included in the scope of this study's analysis.

3.2. Learning Curve Model

NOAK cost trajectories are computed applying Wright's Law at the component level, with the category-specific learning rates listed in Table 2 [13, 27]. The capital cost of the Nth plant in a production sequence is quantified by Eq. 2, as:

$$C_N = C_{\text{FOAK}} \times (1 - \text{LR})^{\log_2(N)} \tag{2}$$

where C_N is the capital cost of unit N in millions of 2024 U.S. dollars, C_{FOAK} is the unit 1 cost, LR is the learning rate per production doubling (dimensionless), and $\log_2(N)$ is the number of cumulative production doublings. Four learning rate regimes are applied: 23–24% per doubling for factory-fabricated primary reactor components (heat pipes, fuel assemblies, pressure vessel internals); 18% for reactor structures and power conversion; 8% for site civil works, balance-of-plant, and electrical systems; and 8–15% for U.S. NRC licensing costs by tier [13]. The 8-15% NRC licensing rate is derived from MOUSE's analysis of ADAMS review-cost patterns across vendors [13, 14] and carries higher epistemic uncertainty than the hardware-side rates. Because no MMR has yet reached serial production, these rates are applied as factory-fabrication analogues from the MOUSE dataset rather than observed MMR deployment data. The fleet-weighted average across all accounts ranges from 13.0% to 14.5% per doubling. The NOAK threshold (i.e., the unit at which 90% of the asymptotic cost reduction is achieved) is identified by solving Eq. 2 for N at which $(C_{\text{FOAK}} - C_N)/(C_{\text{FOAK}} - C_\infty) = 0.90$; this corresponds to units 44–48 across the full vendor set [13, 29].

3.3. Centrus Case Study Economic Model

The 50-year financial model examines two ACP demand levels: Scenario A (2025) with 25 MWe installed, 21.7 MWe average demand, and 3.8 million SWU/year; and Scenario B with 40 MWe installed, 37.1 MWe average demand, and 7.6 million SWU/year. The FOAK specific capital cost averages \$18,000/kWe, within the vendor range (\$7,497-\$36,131/kWe). Annual O&M costs are set at \$235/kWe/year, escalating at 3% annually to reflect cost growth [13]. Nuclear fuel costs start at \$10/MWh and escalate 2.5% per year over 50 years, in line with INL projections [13]. This conservative assumption maintains MMR's competitiveness, as fixed costs suggest an understated long-run NPV advantage for co-siting. The baseline grid electricity price is \$86.3/MWh for Southern Ohio [24], escalating at 3% annually, with a high-escalation variant at 4%/year. A zero-real-escalation scenario shows MMR LCOE falls below grid prices in Year 1 with a 30% ITC. Financing includes a 30-year loan at 2.5-5.5% interest [31] and ITC at 0%, 30%, and 50% of eligible capital [30]. The LCOE is outlined in Eq. 3.

$$\mathrm{LCOE} = \frac{\mathrm{CRF} \times (1 - \mathrm{ITC}) \times C_{\mathrm{cap}} + C_{\mathrm{O\&M}}}{E_{\mathrm{annual}}} + C_{\mathrm{fuel}} \tag{3}$$

where $\mathrm{CRF} = r(1+r)^T/[(1+r)^T - 1]$ is the capital recovery factor at real discount rate $r = 0.08$[7] and project lifetime $T = 50$ years [33], C_{cap} is total capital cost, $C_{\mathrm{O\&M}}$ is annual O&M cost, E_{annual} is annual generation in MWh, and $C_{\mathrm{fuel}} = \$10/\mathrm{MWh}$ is the specific fuel cost. The 50-year NPV of MMR co-siting relative to the grid-only scenario is represented by Eq. 4, as:

$$\mathrm{NPV} = \sum_{t=1}^{T} \frac{C_{\mathrm{grid},t} - C_{\mathrm{MMR},t}}{(1+r)^t} - (1 - \mathrm{ITC}) \times C_{\mathrm{cap}} \tag{4}$$

where $C_{\mathrm{grid},t}$ and $C_{\mathrm{MMR},t}$ represent annual electricity costs, $(1 + r)^t$ is the present-value discount factor at a real discount rate $r = 0.08$. The upfront capital cost $(1 - \mathrm{ITC}) \times C_{\mathrm{cap}}$ is incurred at $t = 0$ and requires no discounting. Annual MMR operating costs include escalating O&M costs (\$235/kWe $\times(1.03)^t$), escalating fuel costs (\$10/MWh $\times(1.025)^t$[8], prorated over seven years, which is the estimated average refueling cycle for the MMR vendors considered, and an estimation of \$500,000/year standby charge[9]. Grid costs increase 3% annually from a baseline of \$86.3/MWh, with outage penalties growing at 2% from Year 1 values (\$897,077 for Scenario A; \$1,794,155 for Scenario B). Learning curve costs for Centrus scenarios are Unit 1 (FOAK) at \$21,246/kWe (4% financing), Unit 5 at \$14,779/kWe (7%), and Unit 10 at \$12,767/kWe (6%)[10].

Table 3. FOAK capital cost estimates by vendor and technology family, derived from the MOUSE methodology. \$/kWe calculated at rated power output.

Vendor	Technology	Power (MWe)	FOAK (\$M, 2024)	\$/kWe	Reg. Tier
Westinghouse	HPMR	5	149	29,835	Tier 1
Oklo	LMFR	15–25	187	7,497	Tier 1
X-Energy	GCMR	10	170	16,955	Tier 2
BWXT	GCMR	12	199	16,609	Tier 2
NANO Nuclear	GCMR	3.5–15	229	15,282	Tier 1
Hadron Energy	PWR	10	361	36,131	Tier 3
Last Energy	PWR	20	528	26,413	Tier 3

3.4. Government-to-Private Transition Metric

The government-to-private transition threshold (N^*) is defined as the fleet unit number at which the NPV (Eq. 4) first turns positive under a given ITC scenario. Three ITC scenarios — 0%, 30%, and 50% — are evaluated in parallel to bracket the policy space from no federal support to current legislative levels (30%

[7] A real discount rate of 8% is adopted as a representative corporate hurdle rate for U.S. industrial energy projects, consistent with established practice in nuclear cost-of-electricity analyses [32, 33].

[8] The 2.5% fuel escalation was extracted from INL/PRT-24-77048 study [10].

[9] The standby charge is a fee the grid operator charges for keeping the facility connected and reserving backup grid capacity. Even with an on-site MMR as the main power source, the facility stays connected for emergencies. Utilities recover these costs with fixed demand or standby tariffs, regardless of how much grid energy is used.

[10] Financing is differentiated by fleet stage: Unit 1 is financed at 4% via DOE LPO support; Unit 5 transitions to 7% commercial financing; Unit 10 reflects an established commercial rate of 6% [31]

IRA Section 48C) and the proposed enhanced nuclear ITC (50%) [30]. The expected annual grid outage cost, escalating from $897,077/year (Scenario A) and $1,794,155/year (Scenario B) at 2% per year, is incorporated into the $C_{\mathrm{grid},t}$ stream as an avoided-cost benefit accruing to the MMR scenario, since co-sited on-site generation eliminates the majority of transmission-related outage exposure. The 2% annual outage escalation captures the documented trend of increasing System Average Interruption Duration Index (SAIDI) values attributable to extreme weather events and grid load growth from electrification and data center demand [23].

4. RESULTS AND DISCUSSION

4.1. FOAK Capital Costs by Vendor and Technology

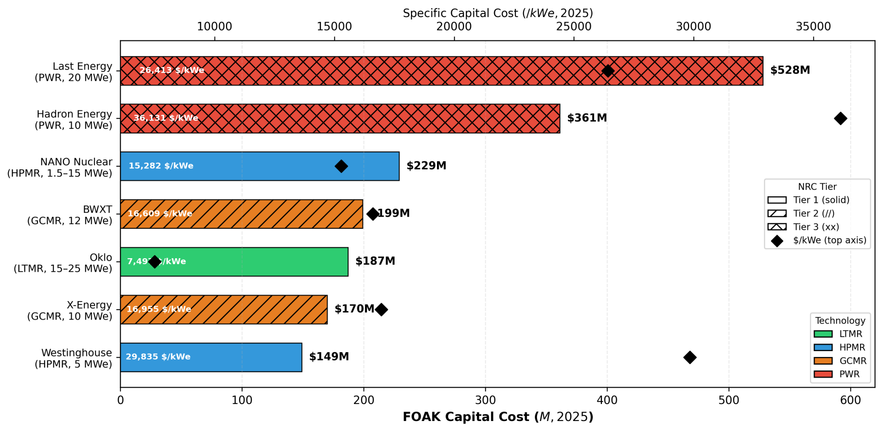

Fig. 1. FOAK capital cost by vendor (bar chart, colored by technology family; $$/kWe on secondary axis). LMFR/HPMR/GCMR designs cluster well below PWR-based alternatives across both metrics.

Across the seven vendors, our FOAK cost estimates range from $149 million for the Westinghouse eVinci to $528 million for the Last Energy PWR20, a 3.5× spread, illustrated in Table 3. This spread is consistent with expectations: the MOUSE methodology independently captures two orthogonal cost drivers, technology architecture (factory fabrication fraction and balance-of-plant complexity) and rated power output, whose compounded effect across a vendor set spanning 5–25 MWe and three distinct technology families predictably produces multi-fold capital cost variation [13]. Technology class is the dominant cost driver: LMFR, HPMR, and GCMR designs average $187 million per unit, compared to $445 million for PWR-based alternatives — a 57% differential attributable to the higher factory fabrication fraction and simpler balance-of-plant of non-LWR designs [13]. Per-kilowatt cost tells a similar story, with a spread of 4.8× from Oklo ($7,497/kWe) to Hadron ($36,131/kWe), which is driven, though not entirely, by the size effect of each reactor design. Hadron's high $/kWe reflects the size penalty at 10 MWe under the 0.6-exponent scaling of Eq. 1. The NRC regulatory tier is worth noting here as well. We estimate that the Tier 1 group saves $4.7 million per unit relative to the Tier 3 group (at the moment of the analysis). Across a 50-unit deployment program, this scenario compounds to $235 million, representing a fleet-level difference large enough to make U.S. NRC engagement maturity a cost parameter of comparable significance to technology choice. Fleet unit numbers refer to cumulative national deployments, not units deployed exclusively at Centrus; the ACP represents one early-adopter customer whose LCOE and NPV outcomes at units 1, 5, and 10 reflect the cost position it would hold in a nationally deployed MMR program.

4.2. NOAK Trajectories, Fleet Learning, and Regulatory Tier Impact

Component-level Wright's Law learning curves reduce FOAK costs by 44-64% across the seven vendors, bringing NOAK costs (unit 100) to a range of $58-$189 million, as presented in Fig. 2. Across all vendors, the NOAK threshold (90% of asymptotic cost reduction) is crossed at units 44-48 — distinct from the commercial break-even threshold N^* defined in Section 4.4. A project crossing N^* at Unit 10 is financially self-sustaining under the model's assumptions but still operates at approximately 60-70% of the asymptotic NOAK cost floor, meaning cost-learning benefits remain substantial through units 10-44. Three major trajectories include Westinghouse ($149M → $58M, 61% reduction), Oklo ($187M → $78M, 58% reduction), and Last Energy ($528M → $189M, 64% reduction). The steeper absolute dollar reductions for PWR-based designs simply reflect where they start (i.e., higher FOAK costs mean more room to fall), but LMFR and HPMR designs hold a durable $/kWe advantage that persists across the full learning curve. Although PWR technology is mature at large reactor scale, that maturity does not transfer to the 10–20 MWe microreactor scale: PWR-based microreactors inherit the pressurized primary circuit and containment requirements of their large-reactor heritage, sustaining a site-construction cost structure that factory-assembled non-LWR designs largely avoid. The higher learning rates for LMFR, HPMR, and GCMR designs (23–24% per doubling versus the lower effective rate for PWR-based units) therefore reflect not technological immaturity but a fundamentally more favorable manufacturing architecture at this scale class. At the fleet level, a 50-unit deployment generates aggregate savings of $4.8 billion against flat FOAK pricing. These aggregate savings arise because the fleet continues to expand even when the first few reactors each lose money on their own (i.e., carry a negative NPV): every early unit deployed, despite being individually unprofitable, drives manufacturing cost reductions for all subsequent units through learning-curve effects. This highlights the government's role in *de-risking* at the FOAK stage by absorbing those initial financial losses so the technology can reach commercial cost maturity. The $235 million fleet-level savings gap between Tier 1 and Tier 3 vendors, as presented in Table 4, at the 50-unit scale, reinforces the economic incentive to advance regulatory engagement depth.

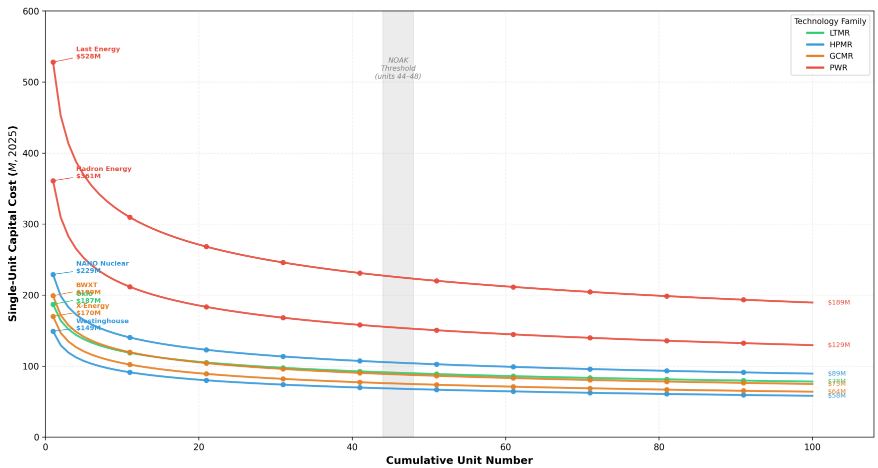

Fig. 2. Learning curve cost trajectories ($M, 2025$) vs. cumulative unit number (1–100) for all seven vendors, colored by technology family. NOAK threshold band (units 44-48) marked. PWR-based designs show larger absolute reductions but higher asymptotic floors.

Table 4. U.S. NRC regulatory tier cost impact: per-unit savings, 50-unit fleet savings, and licensing cost as percentage of FOAK total.

Tier	Vendors	Per-Unit Licensed Ahead Savings vs. Tier 3	50-Unit Fleet Savings	Full Tier 3 Licensing Cost
Tier 1	Oklo, Westinghouse, NANO Nuclear	$4.7M	$235M	$30–$32M
Tier 2	BWXT, X-Energy	$2.5M	$125M	$30–$32M
Tier 3	Hadron Energy, Last Energy	$0M	$0M	$30–$32M

4.3. Centrus Case Study: LCOE Analysis

At a specific cost of $18,000/kWe and an 8% real discount rate, the MMR LCOE without ITC support is $137.5/MWh, which is 59% above the $86.3/MWh grid baseline. A 30% ITC (IRA Section 48C) lowers the effective LCOE to $105.6/MWh, while a 50% ITC results in $84.4/MWh, nearing grid parity. The higher LCOE compared to earlier estimates is due to updated O&M costs ($235/kWe/year based on NEI data), increasing the fixed cost contribution from the INL reference estimate used in MOUSE. Interestingly, the LCOE for Unit 5 ($155.6/MWh without ITC) is higher than for Unit 1 ($145.3/MWh) despite lower capital costs for Unit 5, as Unit 1 benefits from 4% DOE-backed financing versus 7% commercial rates for Unit 5, leading to a temporary increase in financing burden. By Year 10, Unit 10 achieves a lower LCOE of $122.6/MWh at 6% commercial rates. The projected 3% annual grid price increase makes MMR cost scenarios more favorable over 50 years, with the grid baseline expected to reach $151.3/MWh by Year 20, $203.4/MWh by Year 30, and $367.3/MWh by Year 50. The no-ITC MMR LCOE of $137.5/MWh will fall below the Year-20 grid price, indicating a strengthening economic case for MMR co-siting thereafter, regardless of tax policy changes.

4.4. NPV Analysis and Government-to-Private Transition

We find a consistent government-to-private transition structure across both Centrus ACP demand scenarios in the 50-year NPV analysis. Table 5 summarizes the results, and Fig. 3, which shows an average scenario of the different reactor technologies, depicts the different scenario curves.

Three milestones emerge. Unit 1 requires at least 50% ITC (for Scenario B) to reach a positive NPV. This is perhaps the starkest finding in the transition analysis: without that level of government de-risking factor at the FOAK stage is, in this model, a prerequisite rather than an accelerant. By Unit 5, a positive NPV is achievable at 30% ITC, opening the path from full to partial government support. Unit 10 represents the commercial break-even ($N^* = 10$) with 30% ITC, indicating the point at which private capital can sustain the 50-year co-siting program without ITC support, as defined by Eq. 4. This does not imply that 10 units will be deployed at a single site but spread across the country. This threshold differs from the NOAK cost-maturity threshold (units 44-48, Section 4.2): at $N^* = 10$, the program is financially self-sustaining yet benefits from significant cost learning in later deployments. For every dollar of ITC support at Unit 1, we estimate \$3–\$5 in reduced lifecycle costs for future units, a multiplier seen in previous government-supported nuclear commercialization efforts [11, 29, 32]. The increasing outage cost — rising at 2% per year from \$897,000/year (Scenario A) and \$1,794,155/year (Scenario B) — enhances the MMR scenario's avoided-cost benefits, improving NPV by approximately \$11M (Scenario A) to \$22M (Scenario B) over the project lifetime.

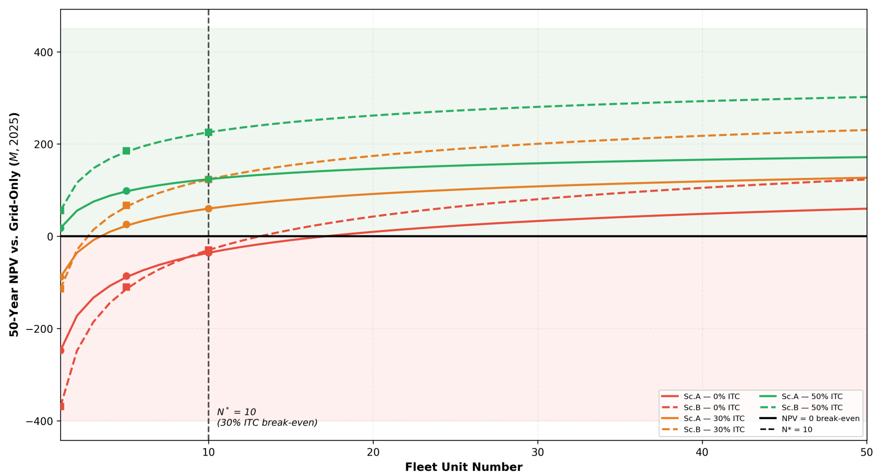

Fig. 3. Government-to-private transition diagram: 50-year NPV vs. fleet unit number (1–50) for Scenario A and Scenario B. Three ITC bands (0%, 30%, 50%) shaded. Break-even threshold $N^* = 10$ (no ITC) highlighted. ITC crossover points at units 1 and 5 are annotated.

4.5. Technology Selection and Sensitivity

HPMR, GCMR, and LMFR designs are well-suited for the Centrus ACP's electricity-dominant load, offering cost structures and operational profiles better aligned with continuous enrichment operations than PWR-based designs. The Westinghouse eVinci (Tier 1, \$149M per unit FOAK) has the lowest capital entry point, making multi-unit deployment desirable, while Oklo's LMFR (\$187M, \$7,497/kWe) offers the lowest specific cost and can meet both demand scenarios with a single unit. BWXT BANR (Tier 2, \$199M) covers Scenario B with three units. PWR-based designs are less optimal for the analyzed demand scale due to their uncompetitive cost structure at this level. A deterministic one-at-a-time sensitivity analysis (Table 6) bounds the impact of key parameters: capital cost significantly impacts LCOE and NPV, with a ±20% variation in the \$18,000/kWe base affecting LCOE by ±22.4/MWh. Grid price escalation is crucial for long-term economics, with each percentage point adding approximately \$280-\$560 million to the 50-year NPV. The conservative 8% discount rate suggests that access to U.S. DOE LPO financing at 2.5-4% can improve FOAK NPV by \$45-\$96 million, highlighting the need for a financial sensitivity analysis before investment decisions. Learning rates, with high epistemic uncertainty, emphasize the need for the first 10-20 commercial deployments to solidify empirical data [9, 10, 13].

Table 5. 50-year NPV of MMR co-siting vs. grid-only procurement at Centrus ACP, by fleet unit stage and ITC scenario (8% real discount rate, 2025$).

Fleet Unit	No ITC	30% ITC	50% ITC
Scenario A — 21.7 MWe (3.8M SWU/year)			
Unit 1 (FOAK)	-$274.9M	-$115.5M	-$9.3M
Unit 5	-$113.2M	-$2.4M	**+$71.5M**
Unit 10	-$62.9M	**+$32.8M**	**+$96.7M**
IRR† (no ITC): 5.40% | Payback: 24 years | 50-year total advantage vs. grid: $1,752M			
Scenario B — 37.1 MWe (7.6M SWU/year)			
Unit 1 (FOAK)	-$392.8M	-$137.9M	**+$32.1M**
Unit 5	-$134.1M	**+$43.2M**	**+$161.4M**
Unit 10	-$53.7M	**+$99.6M**	**+$201.7M**
IRR (no ITC): 5.32% | Payback: 24 years | 50-year total advantage vs. grid: $2,647M			

†IRR - Internal Rate of Return

Table 6. Sensitivity analysis: LCOE and Unit 10 NPV impact of ±20% variation in key parameters.

Parameter	Baseline Value	Variation	ΔLCOE ($/MWh)	ΔNPV Unit 10 (Sc. A / Sc. B)
FOAK capital cost	$18,000/kWe	±20%	±$22.4	±$72M / ±$144M
Grid escalation rate	3%/year	±1%/year	±$65.3 (yr 50 grid price)	±$280M / ±$560M
Real discount rate	8%	±2%	±$8.4	∓$45M / ∓$90M
ITC percentage	30%	±10%	±$11.2	±$25M / ±$50M
O&M escalation rate	3%/year	±1%/year	±$4–$6	±$12M / ±$24M
Nuclear fuel escalation rate	2.5%/year	±1%/year	±$2	±$5M / ±$9M
Outage hours (yr 1)	11 hrs/yr	±5 hrs	-	±$5M / ±$9M

5. CONCLUSION AND FUTURE WORK

Two gaps in the MMR economics literature drove this work. The first: no cross-vendor, account-level FOAK-to-NOAK cost framework had been developed for the current U.S. MMR vendor landscape. The second: no project-level, 50-year financial analysis had been applied to a specific, named NFC facility at actual demand scale. We addressed both through five contributions, which are: 1) cross-vendor FOAK cost estimates for seven vendors across four technology families (MOUSE methodology, 82 accounts); 2) component-disaggregated NOAK trajectories via Wright's Law with category-specific learning rates; 3) quantification of U.S. NRC regulatory tier cost impacts; 4) a 50-year LCOE and NPV analysis for two Centrus ACP demand scenarios under three ITC levels; and 5) a government-to-private investment transition framework with a defined commercial break-even threshold. These points together constitute, to our knowledge, the first reproducible, account-level analytical basis for MMR co-siting decisions at NFC facilities.

Three key findings emerge from the analysis. First, there is a 57% cost gap between non-LWR designs (average $187M) and PWR-based alternatives ($445M), driven by a 0.6 power-law scaling exponent and the higher factory fabrication fraction of LMFR, HPMR, and GCMR designs. NRC Tier 1 engagement contributes an additional $235 million in savings at a fleet of 50 units, making regulatory maturity as important as technology class. Second, the updated O&M parameter of $235/kWe/year shifts the commercial break-even threshold N^* to beyond Unit 10 without ITC support. This implies that maintaining a 30% ITC through Unit 10 is essential for positive NPV, as project IRR (5.40% for Scenario A and 5.32% for Scenario B) does not meet the 8% hurdle rate without ITC. Lastly, the combination of a 3% annual grid price increase and a 2% annual rise in outage exposure leads to grid costs that exceed the no-ITC MMR LCOE by Year 20. The projected 50-year cash advantage of $1.75 billion (Scenario A) to $2.65 billion (Scenario B) does not rely on favorable tax policies. Additionally, outage costs may be underestimated, as the risk of cascade failures and reliance on ACP as the sole domestic HALEU source pose significant supply chain and national security concerns.

We recommend Tier 1 vendors, at the present moment, combined with a 30-50% ITC for initial deployment. The 30% ITC achieves immediate grid parity in our model, and at 50%, the positive NPV is reached at Unit 1. Fleet Unit 10 is the milestone for transitioning to privately financed, self-sustaining deployment (N^* crossed). Two directions remain. The first is extending our model to other NFC facility types (e.g., conversion, fuel fabrication, and spent fuel reprocessing), where co-siting opportunities may be similarly compelling. From an economic perspective, the cost-and-learning components are facility-agnostic, with site-specific factors incorporated into the developed framework. The second is connecting the economic viability metrics to the probabilistic risk framework for MMR and NFC facility co-siting, enabling joint evaluation of cost and risk. More broadly, applying Wright's Law to pre-commercial MMRs is inherently extrapolative: it presumes a stable production-doubling mechanism not yet empirically observed for any MMR, so the projected NOAK trajectories should be read as model-based bounds such that the first commercial units would be needed to validate.

CONFLICT OF INTEREST DECLARATION

The authors declare that they have no conflicts of interest regarding the subject matter or materials discussed in this manuscript.

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