Advanced Nuclear Project Financing Options

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Prepared by:
Becca Gillespie, Managing Director
Energy Systems Network
111 Monument Cir, Suite 2200 Indianapolis, IN

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Executive Summary

Nuclear power plants have been providing a reliable zero-emissions power supply to the United States power grid since 1954. Over the last 70 years, nuclear power plants have been funded using a traditional rate-based finance approach, offering a reliable source of capital that is aligned with the beneficiaries of the power that is generated. Over the last 20 years, an additional model for financing energy generation has emerged using a combination of private capital, federal tax credits and loan guarantees, and power purchase agreements to add hundreds of gigawatts of renewable energy to the US grid. As we enter a new era of developing nuclear power generation with the emergence of advanced reactors, including Small Modular Reactors (SMRs), there is an opportunity to consider a mix of financing options that have not previously been available to nuclear plants.

The financing industry has demonstrated significant interest in the advanced nuclear power sector in the past two years, with record amounts of private equity being invested in the industry; $800 million in 2024. The growing demand for reliable power, and projections that nuclear power can produce commercially competitive energy ($76-141/MWh) are driving strong market interest. However, with only one advanced nuclear project completed in the U.S. new nuclear projects in the U.S. cannot be financed by commercial lenders. Successful financing of nuclear projects today will most likely involve leveraging the support of the federal government, appropriately risk-sharing across various project stakeholders and investor-types and working collaboratively across projects.

The ways new advanced nuclear projects are financed will continue to include rate-based investments, as has been the case in the past. Traditional utilities, including TVA, Duke, Dominion and AEP, are currently moving forward with new nuclear projects. However, several projects have been announced are led by private developers. The developer-led efforts are formulating private and public financing mechanisms that significantly reduce or remove the use of rate-payer financing during the development and construction phase or, in some cases, during operations. The idea of developer-led, privately-financed power plants is not new; it is the method most renewable and many natural gas power plants have been financed over the past two decades. But the higher upfront costs and increased regulatory requirements associated with nuclear are driving financers to adapt the existing financing models for early projects.

In line with this movement, many flavors of nuclear project developers are emerging: traditional large publicly traded developers with existing nuclear portfolios (Constellation, NextEra and Vistra), are entering this space at the same time as venture-capital backed-startups (Elementl, The Nuclear Company) and private equity backed startups (e.g. Entra1, NVisions, mid-sized solar developers). Long-term, energy off-takers, especially AI data center operators, site owners, reactor technology developers, EPC firms executing the project and special interest investors may all be asked to join the financing stack as minority shareholders and share some project risk.

Commercial bank lending to new nuclear projects is not currently feasible given banking regulations and the level of risk in nuclear projects. Therefore, only two options for debt financing exist today: loans/loan guarantees from DOE’s Energy Dominance Financing Office (EDF), or structured private debt. The DOE EDF loan guarantees, with loans up to 80% of total project costs and interest rates of about 5%, can significantly mitigate the risks and costs associated with the project finance. Further, the federal government’s Investment Tax Credit (ITC) that can cover up to 50% of project costs, offers a critical incentive that makes nuclear power economic and, because it is tied to total costs, can absorb up to 50% of the risk of cost overrun.

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1. Overview

Obtaining development financing for new nuclear projects relies on the project's ability to repay financial obligations, while providing a market return for investors. The pillars of a financeable nuclear project are not distinct from those of any other large-scale infrastructure project that requires financing. However, the historic road map of a financial model for a nuclear power plant has been reliant on subsidies and government intervention to make it work. The current energy landscape must have a more traditional and nimble commercial approach to financing nuclear to meet insatiable capacity demands and keep the United States secure and competitive on a global scale. This report walks through each of the relevant elements of a nuclear infrastructure investment decision and compares how well current nuclear projects meet various thresholds for market viability and highlights which credible parties can finance new nuclear projects at each phase of development.

Solid Business Case:

- **Cost:** What are the hard and soft costs are attributable to the development, construction and commissioning of a nuclear power plant?
- **Value Proposition:** What is the revenue value from the production of energy over the engineered life of a nuclear power plant?
- **Profits:** Does the profit potential of a nuclear reactor deployment outweigh actual and/or perceived market risk? Has a baseline return for a multi-billion-dollar nuclear investment been benchmarked in the United States?

Manageable Risks:

- **Manage risk of cost and schedule:** Are the risks associated with the construction cost and schedule known and manageable?
- **Manage risk of value proposition:** Are the risks to the economic value proposition known and manageable?
- **Share or offset risk:** If cost and schedule risks cannot be mitigated solely by the developer, who can share or contractually assume that risk? How can debt and equity be structured to align with the risk profile of the project?

Regulatory Certainty:

- **Cost and Schedule:** Will regulatory changes materially alter the initial cost and benefit calculation? Will regulatory changes modify profit expectation and impact schedule performance? Will the government incentives that exist today be available to fund future projects?

2. State of the Industry

Nuclear Power has been attracting significant interest over the past three years, largely driven by the growing demand for clean, firm power and the ongoing retirement of existing power plants that are reaching the end of their useful life. Before discussing the viability of nuclear finance item by item, it is useful to provide an overview of government and market investments that demonstrate the current momentum to develop new nuclear reactors. All subsequent discussions of cost, benefit, and risk support the case for investing in new nuclear power. However, the actual flow of investment dollars into and out of projects is the most important indicator of the state of the industry.

2.1 Positive Market Indicators

Demand Signals

The largest driver of interest in nuclear power is the strong demand signal coming from the electric power sector. After decades of relatively flat load, load growth is predicted throughout the U.S, with the EIA predicting load growth of 2.2% in 2025 and 2026. Furthermore, MISO predicts annual load growth of 1.6% per year (range of 1.3-2.0%) from 2024 through 2044, up from flat load from 2007 to 2023.[1] MISO's load zone 6, which includes most of Indiana and parts of Kentucky, is predicted to have 2.1% per year load growth from 2023 through 2030.[5] PJM has predicted load growth across its footprint at 3.1%, over the next 10 years; the AEP load zone (which includes part of Indiana and the AEP territories in Michigan, Ohio, West Virginia, Virginia and Kentucky) is projected to have 5.7% load growth over the next ten years.[2] Demand is driven by a variety of factors, including continued electrification of residential lifestyles, onshoring of heavy load intensive manufacturing, critical mineral processing, and the establishment of new data centers.[3] Data centers are leading to load growth in Indiana, with NIPSCO, AEP, Duke, and AES all citing data center demand as a major driving factor in their predicted load growth over the coming years.[4] Data center's 99.9999% uptime and reduced carbon performance requirements are particularly well suited to nuclear energy production because of the reliable and extensive capacity generated at each nuclear plant with low to no carbon emissions.

In 2023, Indiana imported about 14% of the energy that it consumed[5]. In order to be able to accept new loads, particularly large loads like data centers, Indiana utilities and developers will need to build or buy new generation capacity.

Project Announcements

The number of advanced nuclear power projects has expanded over the last five years, and now, according to the Nuclear Energy Institute, there are a total of 79 advanced nuclear power projects across North America, including one completed project, 6 projects under construction, and 15 planned projects, see Figure 1. As defined by this dashboard, each project can have multiple reactors planned for the site.

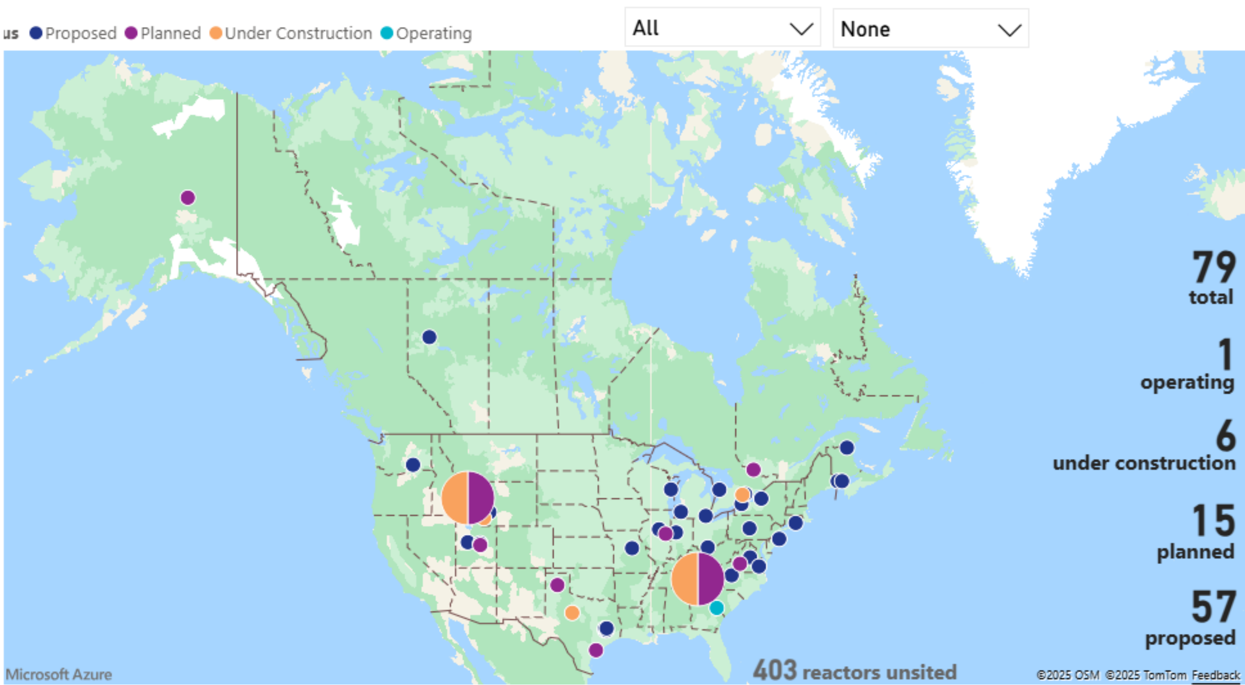

Figure 1: Nuclear Energy Institute's New Reactor Project Dashboard

However, of the 6 projects under construction, only 2 are installing commercial reactors, while the other 4 are demonstration reactors:

1) Four GE Hitachi BWRX-300 reactors are being built by Ontario Power Generation in Ontario, Canada. These reactors will have a combined power capacity of 1200 MW. The same design will be used for a plant being built by the Tennessee Valley Authority (TVA) at their Clinch River site.
2) One Terra Power Natrium reactor is being built in Kemmerer, Wyoming. At this time the project has been issued a Limited Work Authorization (LWA) and has begun pre-development site activities including rough grading and construction activities related to non-safety related structures and its power block. The construction permit for the nuclear island will complete it's review by 12/31/2025, and will likely be issued in 2026[6].

Two reactors came online and three restart projects underway

The first reactors to be built in over 30 years, were at Plant Vogtle, in Waynesboro, Georgia. Vogtle 3 reached criticality on July 31, 2023 and Vogtle 4 reached criticality on April 29, 2024. Vogtle 3 a Gen III+ AP-1000 design from Westinghouse, which includes integrated passive safety features and enhanced steam turbine design features for more efficient energy production. While the final schedule exceeded the initial planned schedule by more than 7 years, and cost were significantly higher than the original estimation, the completion of this units have nevertheless led to increased confidence in the United States' ability to complete nuclear mega-projects.

Since the completion of the Vogtle project, three nuclear restart initiatives have been announced in the U.S., underscoring the growing demand for nuclear power:

1) Holtec Palisades Restart: In mid-2023, Holtec International began the process of restarting the 800 MW Palisades Reactor (which ceased operation in 2022).[7] The project is planned to come back online in the fourth quarter of 2025.[8] This is the first restart in the U.S.

2) Constellation Crane Clean Energy Center: In September 2024, Constellation announced the restart of Unit 1 at the former Three Mile Island (TMI) site, under the new name Crane Energy Center. The 835 MW reactor is set to restart in 2027, after Constellation received accelerated approval on its interconnection request to PJM in 2025.[9] This restart is tied to a Power Purchase Agreement (PPA) with Microsoft.[10]

3) NextEra Duane Arnold Restart: In January 2025, NextEra submitted documents to the NRC outlining a restart and regulatory path for the Duane Arnold plant (ceased operation in 2020).[11] In March 2025, NextEra proposed restarting the 610MW reactor to the NRC with an estimated COD of Q4 2028.[12]

Venture Capital and Private Equity Investments in Nuclear Startups

In recent years, the investment in nuclear technology startups has skyrocketed. In the North American market, after five or more years with minimal private equity and venture capital investments in nuclear technology startups, the years of 2022, 2024 and 2025 (through June) saw upwards of $2 Billion[13] of private equity and venture capital investments according to Bloomberg New Energy Finance data (See Fig. 2).[14] Note these investments are in reactor technology companies, and not project development and construction costs. Another data aggregator, S&P Global, using a slightly broader net to measure investments in next-generation nuclear fission technologies, e.g. they included investments in HALEU fuel, showed private equity investment of $783 million in 2024, up 13-fold over the PE investments in 2023, and about double the recent peak of PE investment in 2021.[15]

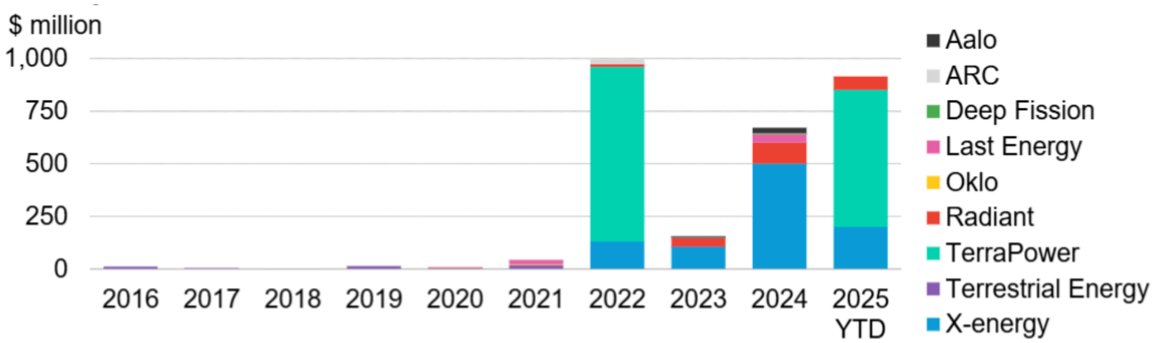

Figure 2: Private Equity and Venture Capital Investment in Nuclear Technology Startups.

Nuclear Power PPAs

Besides equity investments, the large data centers have been active in signing Power Purchase Agreements (PPAs) for nuclear power. For the three projects shown in Table 1, the PPAs have been estimated by the consulting firm, Jeffries. These prices are a significant premium over power prices from solar or wind PPAs, which typically cost $30-$40/MWh, which, because of the resources' intermittent nature, are not firm or dispatchable.

Table 1: Nuclear Restart and Relicensing PPA's with estimated Prices

Seller	Buyer	Amount	Price (est.)	Power Plant
Constellation	Meta	1,092 MW	$70/MWh[16]	Clinton (re-license)
Talen	AWS	1,620 MW	$88/MWh[17]	Susquehanna (re-license)
Constellation	Microsoft	835 MW	$110-$115[18]	Crane (restart)

These deals were the first PPAs to make a significant contribution in the U.S. corporate PPA volumes, which have historically been dominated by solar and wind, as shown in Figure 3.[19] Also included in the 2025 PPA totals shown in Figure 3, is an agreement between Google and a fusion company, with no reported price estimates.

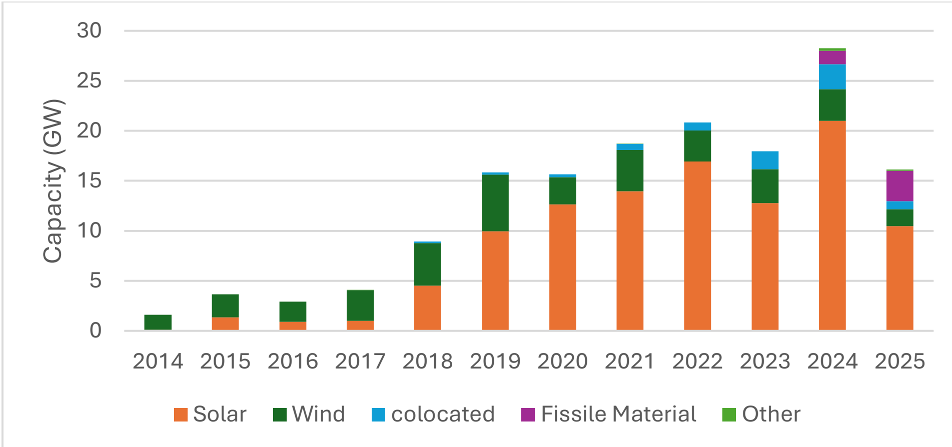

Figure 3: Annual U.S. Corporate PPA Volumes by Technology> Bloomberg New Energy Finance

Nuclear power plant development interest among Indiana utilities

Load serving entities in Indiana have begun to explore nuclear SMRs as part of their Integrated Resource Plan (IRP) process. Indiana Michigan Power (AEP), which owns and operates the Cook Nuclear Power plant in Michigan that supplies power to Indiana customers, announced their plan in January of 2025 to develop an SMR at their Rockport coal power plant site.[20] Duke Indiana, with a large deployment of nuclear reactors in its territories outside of Indiana, analyzed new nuclear in their 2024 IRP, ultimately concluding that it was not an economically viable resource at this time. Duke North Carolina is developing an SMR at their Belews Creek site in North Carolina and are pursuing an early site permit for that site with the NRC. This effort will inform their decision making around nuclear development in their other territories, such as Indiana.

AES's 2022 IRP did not include nuclear technology in any of their scenarios, evaluations or discussions. However, in their recent stakeholder engagement meetings for their 2025 IRP, nuclear has been included for consideration, though not selected[21]. Hoosier Energy, a generation cooperative serving 18 cooperatives throughout southern Indiana, is an off-taker of 400 MW of capacity and energy from the Palisades Nuclear Power Plant Restart Project in Michigan and purchases 50 MW of capacity from the Clinton nuclear plant in Illinois according to their 2024 IRP[22]. They did evaluate nuclear in their 2024 IRP, but it was rejected as being not an economical choice at the time. Nationwide, there are other utilities pursuing new nuclear power plant projects, most notably TVA. TVA is developing a project using GE Hitachi technology at their Clinch River site.[23] They also recently announced their partnership with ENTRA1, a developer that works exclusively with NuScale technology, to deploy 6 GW across their 7-state territory.[24]

This growing utility interest is a trend nationwide. Among the Nuclear Energy Institute's survey participants, all of which are utilities currently operating nuclear power plants, more than half said their company's interest in advanced nuclear had grown between Feb 2022 and Feb 2023.[25]

Financing Activity

There is a growing interest in financing new nuclear power plants. In September, 2024, 14 major global banks and financial institutions committed to support the tripling of nuclear energy capacity by 2050. The participating banks included Bank of America, Barclays, Citi, Morgan Stanley, and Goldman Sachs.[26] In their 2025 report, Morgan Stanley Research estimates that global nuclear capacity will grow by 462 GW by 2050, more than doubling the current capacity of 398 GW. This forecast is 53% more than its initial forecast in 2024. They are also estimating that potential investments in the nuclear value chain through 2050 will increase to $2.2 trillion, up from their forecast of $1.5 Trillion made in 2024.[27]

2.2 Government Policy Support

Federal Policy Actions

The primary way the federal government has incentivized the construction of new nuclear is with the Investment Tax Credit (ITC). The ITC gives a tax credit equal to 30-50% of the project costs, typically released upon the start of commercial operation (COD). To qualify for the full amount, the project must have started construction by 2033. While the tax credit existed before the One Big Beautiful Bill Act (OBBBA) of 2025, the tax credit was maintained, whereas other generation sources that had previously received that tax credit, e.g. wind and solar, saw the timelines to begin and complete their projects significantly shortened.

The other important incentive the federal government has in place to drive investment in new nuclear is the loan guarantee authority it gives to the Department of Energy's (DOE) Office of Energy Dominance Financing (EDF) for nuclear power plant projects, formerly known as the Loan Programs Office (LPO). Since the passage of OBBBA, nuclear power plant projects are eligible for loans from the EDF under both Title 1703 and Title 1706. Title 1706, also called the Energy Dominance Financing Program (EDFP)[28] finances new baseload generation projects, including new nuclear power plants.

Previously, the EDF/LPO could provide loan guarantees to new nuclear projects under Title 1703. According to the Title 1703 guidance from 2024, the LPO could provide a loan guarantee for up to 80% of the project costs, at a rate of 0.375-2% higher than the applicable treasury bond rate. Title 1706 can make loans up to 80% of the total project costs at the applicable treasury bond rate with no adder. With an average 10-year treasury bond rate of 4.3% in 2025, and assuming this guidance carries through to the EDF, the total interest rate on a loan for new nuclear would be 4.3-6.3%.[29] Both the interest rate and the debt to equity ratio are much better terms than a new technology, such as a new reactor design, could obtain commercially and both significantly lower the total cost of the power delivered. The EDF has continued to be active in the nuclear industry, despite the ongoing changes. Five out of eight press releases from the EDF issued by the office since the start of the new administration were related to loan disbursements for the restart of the Palisades Nuclear Power Plant in Michigan. In November 2025, the office announced a $1 Billion loan to Constellation for the restart of the Crane Clean Energy Center.[30]

In May 2025, the Trump administration issued four executive orders aimed at jumpstarting a U.S. “nuclear renaissance.”

- **Deploying Advanced Nuclear Reactor Technologies for National Security:** Directs the rapid deployment of advanced reactors at Department of War (DOW) and DOE sites to support critical national security infrastructure.
- **Reforming the Nuclear Regulatory Commission:** Mandates structural and operational reforms at the Nuclear Regulatory Commission (NRC) to reduce regulatory delays and streamline regulatory oversight.
- **Reforming Nuclear Reactor Testing at the Department of Energy:** Expands DOE’s role in testing advanced reactor designs, eases regulations for test reactors, and ensures access to critical nuclear fuel like HALEU.
- **Reinvigorating the Nuclear Industrial Base:** Aims to rebuild the broader nuclear industrial base through domestic uranium production, supply chain support, plant restarts, workforce training, and fuel recycling.

The overall target announced by the administration, to quadruple nuclear capacity by 2050, was an increase over the Biden administration’s goal to triple nuclear capacity by 2050.

In earlier executive orders, “Declaring a National Energy Emergency” and “Unleashing American Energy,” the Trump administration signaled that nuclear power would be treated as a geopolitical and strategic priority rather than a niche clean energy option. The energy emergency order gives the administration sweeping authority to override regulatory roadblocks, accelerate project permitting, and mobilize federal support for energy infrastructure. Meanwhile, “Unleashing American Energy” mandates that agencies review, rescind, or sunset regulations that constrain energy development. Most notably, the administration ordered the government to rescind National Environmental Policy Act (NEPA) regulations and replace them with streamlined agency-level procedures. NEPA processes that had typically been required for any federally incentivized project were known to slow down project acceptance and, at times, create insurmountable project hurdles.

Indiana Policy Actions

Indiana has likewise had a recent flurry of legislative and executive branch activities in favor of new nuclear development. In 2025, the Indiana General Assembly demonstrated strong support for nuclear energy by passing four pro-nuclear acts: HB 1007, SB 423, SB 424, and SB 425. Notably, House Bill 1007 offers a state tax credit against expenses incurred in the manufacture of small modular nuclear reactors (SMRs) in Indiana. SB 424 allows utilities developing nuclear power plants in the state to put early development costs into the rate base and SB423 creates a pilot program where utilities can partner with other developers and still recover early development costs from their ratepayers. SB 425 designates land with existing power generation infrastructure (excluding solar and wind assets) as Energy Production Zones and limits the local permitting requirements for new nuclear built in those zones. These laws collectively signal a commitment to advancing nuclear development, streamlining regulatory processes, and fostering investment in advanced reactor technologies within the state.

In 2023, as part of Indiana's "All of the Above" energy strategy, the legislature commissioned a study on small modular reactors (SMRs) through the Indiana Office of Energy Development. This study, completed by Purdue University and released in 2024, laid the analytical foundation to guide future nuclear projects and policy decisions in the state[5].

Governor-Elect Mike Braun included nuclear energy among the priorities in his policy agenda released in Dec. 2024. This policy position was backed up by Executive Order 48, issued in April 2025, which established the Nuclear Indiana Coalition to coordinate state-level nuclear initiatives among the state's nuclear stakeholders and the state government.

2.3 Counter Indicators

While there is great momentum around industry today, it has not reached a level of maturity where project formation and financing are standardized. Rather, each project must be considered independently, risk must be shared and allocated appropriately among the participating parties, and government support must be leveraged. The big banks, such as Citi, JP Morgan, Goldman Sachs, Bank of America, and Morgan Stanley, have all publicly stated that they cannot invest in new nuclear projects under the current regulatory environment and the risk profile of these investments.[31] The key reasons are:

1. **Cost overruns and mis-estimations:** Only two advanced reactors have been built in the U.S., the Vogtle 3 and 4 units, and they were completed with about 2.5 times their original budget and 10 years over schedule.[32] The V.C. Summer Expansion project in South Carolina,[33] a similar project with two AP1000 units planned, was cancelled after $9 Billion had been spent, due to cost overruns.

2. **Mis-estimated costs:** Another advanced nuclear project, the Carbon Free Power Project in Utah[34] was cancelled when the projected cost of the project grew significantly and the project failed to subscribe the originally committed buyers to the new price.
3. **Few advanced projects:** Of the advanced reactor projects underway, only three have received a construction license from the NRC. That includes two Kairos, Hermes test reactor projects[1], both of which will be built in Oak Ridge Tennessee and one Natura 1 MW_T molten salt research reactor to be built at Abilene Christian University.[35] None are commercial reactors and only one will produce electricity at all (Kairos Hermes 2).

So, while the momentum around new nuclear is substantial, it has not yet reached commercial viability. Early-to-adopt states, however, may stand to make gains that may not be available to later movers, such as siting manufacturing facilities, fuel enrichment facilities, steel suppliers and engineering firms, which can be sources of ongoing economic benefits.

3. Business Case

The primary drivers of a business case for a nuclear investment is that the construction of the assets will provide a reasonable market return within a defined period of time for the stakeholders, and the power delivered to the energy off-taker is a competitive price. In order to evaluate the business case of a new nuclear power plant, it is essential to consider the all-in cap-ex cost of construction compared to the value of the returns, net the expected operating costs. It is also crucial to consider the cost of constructing competing technologies and any differentiators that earn nuclear power a premium over its competitors. The next section will address the risk inherent in each of these measures.

3.1 Cost estimation sources

The Department of Energy's (DOE) Office of Energy Dominance Financing (EDF), formerly the Loan Program Office (LPO) published expectations around the cost of new nuclear based. The cost metric used is the Overnight Capital Cost (OCC), a simplistic metric unique to the power industry, that evaluates the cost to build the power plant as if it were built immediately, devoid of any cost of capital or debt interest. EDF's expects the OCC of the next two-unit AP1000 to be $8,300/kW in 2024 dollars, based on an analysis conducted by MIT. EDF stated that cost true cost of a First of a Kind (FOAK) build for two AP1000's

[1] The Kemerer project, a commercial deployment planned for Wyoming using TerraPower's Natrium reactor has begun non-nuclear construction activities.

should have been \$2,900/kW higher, or \$11,200/kW. In reality, Vogtle's OCC was \$15,000/kW for a two-unit AP1000. The additional \$3,800/kW in costs were attributed, by the EDF report to "Vogtle specific inefficiencies". These cost estimates are on par with the cost of building a new reactor in France, and well above other global costs observed in countries building new reactors today, as seen in Figure 4.[36]

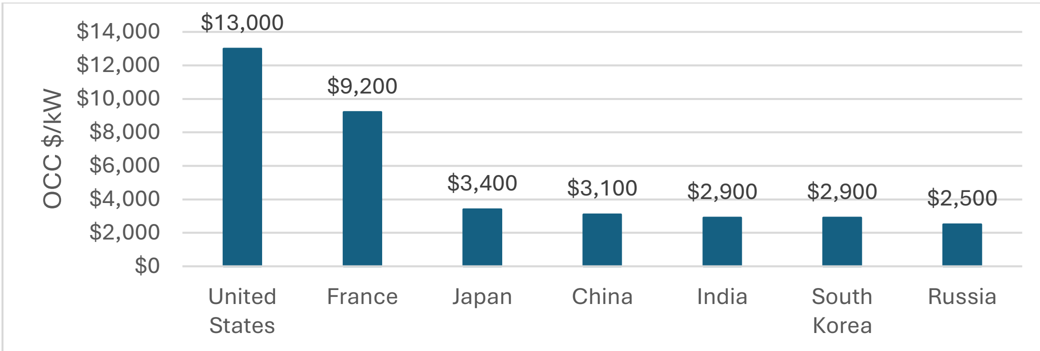

Figure 4: Historical Global Costs of Nuclear Reactors, 2000-2024

The EDF report further estimates that the OCC will continue to fall as additional plants of the same design are built, according to the learning rate or "learning curve". According to the report, the ongoing design standardization, workforce experience building, and supply chain build-up can reduce the Nth-of-a-Kind (NOAK), as shown in Figure 4[37]

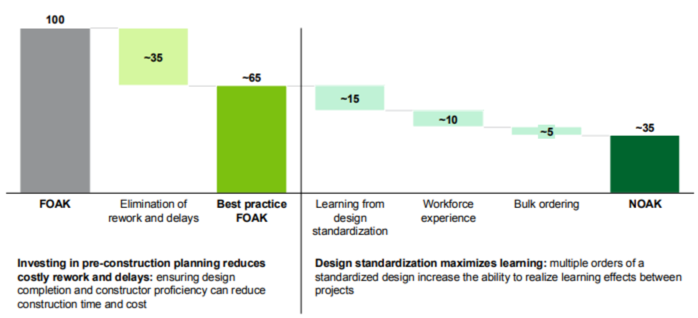

Figure 5: Predicted Relative Cost of Advanced Reactors for First of a Kind, and Nth of a Kind (%)

Because each nuclear reactor built in the U.S., historically, was a custom design, the experience in the U.S. does not demonstrate the effect of the "learning curve". The EDF estimated the impact of the learning curve in their study, as seen in the price difference between the FOAK and the NOAK in Figure 5, but that effect has been observed in the real world in Korea, as seen in Figure 6.[38] There, the country coalesced around a standard design, and as such, saw a drastic reduction in cost of construction over time.

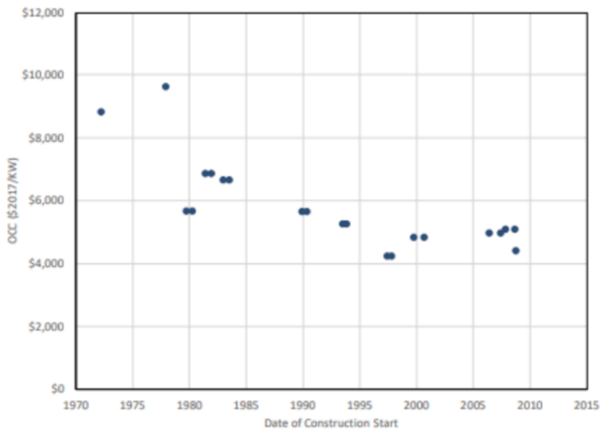

Figure 6: Construction Costs in Korea over time, using a standard design

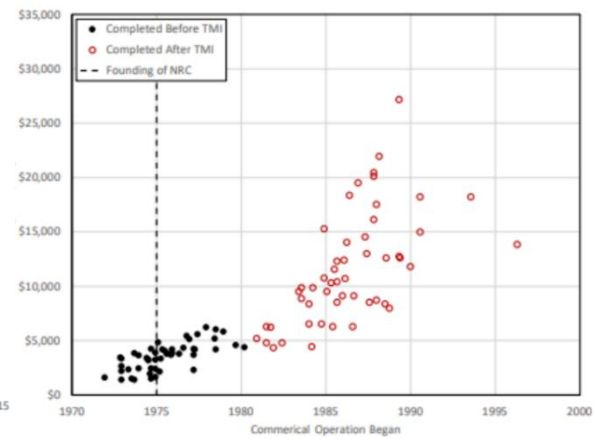

Figure 7: Historical Cost of U.S. Reactor Overnight Capital Costs Before and After TMI

While the United States had a high cost of construction from 2000 to 2024 (e.g. the construction of Vogtle 3 & 4) historic nuclear construction costs in the U.S. were significantly lower before the Three Mile Island incident, as seen in Figure 7[38]. The earliest reactors were below $5,000/kW, with costs ballooning to $10,000-$28,000/kW by 1989.

Of the many reactor vendors, most do not publish or announce all-in cost estimates. Considering that only 12% of the project costs are the reactor and the related nuclear steam system, the reactor vendors would need input from the engineering procurement and construction (EPC) firm, and data on the site specifics, to make a good, all-in OCC estimate.[39] One exception is Rolls-Royce, which has publicly stated that their 470 MW reactor will have an OCC of approximately $3 Billion all-in[40]. This figure, which normalizes to $6,200/kW, is well below the expected FOAK cost expectations published by the EDF in 2024, but aligns perfectly with the FOAK cost expectation published by the EDF in 2023.

As later analysis will show, $6,200/kW or $8,300/kW OCC can create a strong business case for nuclear power providing returns acceptable to the investment community and a competitive all-in price for firm, reliable power. The EDF's FOAK estimated cost of $11,000/kW, on the other hand, would make the business case difficult, and is shown in the below analysis as the "high" cost case. Projects with costs of $10,000/kW or more should consider applying for federal, state or local subsidies to off-set the cost differential between the construction pricing and the wholesale rate of power, to ensure market returns are feasible for all stakeholders.

3.2 Investment Tax Credit (ITC) effects

The federal government has incentivized the buildout of new nuclear power plants with two primary mechanisms through the passage of the Inflation Reduction Act (IRA) in 2022: the

Production Tax Credit (PTC) and the Investment Tax Credit (ITC) in Section 48E. The investment tax credit gives a tax credit equal to 30-50% of the project costs upon the start of commercial operation (COD). A production tax credit (PTC) gives project owners an incentive for each MWh produced over the project's first 10 years of operation. Projects can only choose one, either the PTC or ITC. When the cost of nuclear technology exceeds $6,000/kW, the ITC is preferable to the PTC.[41] Furthermore, the ITC is preferred for projects with a risk of cost overruns because the ITC is based on the total capital costs and will help absorb cost overruns, while the PTC is a fixed rate based on production only and will not absorb any cost overruns. Nuclear projects will qualify for a 30% tax credit by following the basic rules of the program (including rules around sourcing from Foreign entities of concern and paying workers at the prevailing wage), if they begin construction by 2033. Projects can also receive a 10% plus up when more than 55% of the project is manufactured domestically. When asked in 2024, four U.S.-based Gen III+ SMR technology vendors (GE Hitachi, Holtec, NuScale and Westinghouse) stated they expected their technology would qualify for the 10% plus up.[42] The advanced reactors may also qualify. Furthermore, projects qualify for another 10% plus up if the project is located in an Energy Community[2]. Energy Communities are areas where a high percentage of the population has historically been employed in power production or energy mining/production. There are several Energy Communities throughout Indiana. Because the ITC has such a large effect, it is expected that most projects will try to comply with at least the basic rules of the program (30%), and the analysis includes 40% and 50% ITC to show the dramatic effect of complying with those additional rules.

The ITC is not a cash pay-out, but rather a tax credit, and as such, there are some costs associated with claiming the tax credit, e.g. monetization costs. Often, the developer does not have enough taxable equity to take the credit and must transfer that credit to another party who can benefit. NREL has estimated that the cost of monetizing the ITC is 10%, so a 50% ITC, for example, would be similar to receiving a 45% cash discount off the CapEx.[43]

3.3 Cost comparisons with other generators

The Levelized Cost of Energy (LCOE) is a method for incorporating capital costs, amortized over the project's lifetime, and operating costs, and normalizing those costs by the amount of energy the project produces. The shortfall of the LCOE method is that it doesn't account for the value of dispatchable resources versus intermittent renewables and does not consider the benefit of pre-funded managed waste stream upon plant retirement. While it creates a useful comparison between Nuclear and Combined Cycle Gas plants, for

[2] Energy Communities are defined by the Department of Energy by their proximity to retired coal mines and coal power plants, or their dependence on the coal industry for jobs. Details and map from the DOE.

example, there are still attributes of each that are beneficial to the grid that are not captured in the LCOE analysis.

The cost of capital for an LCOE analysis must include the overnight capital cost and interest or returns paid during plant development and construction. The analysis to determine the ratio between the cost of capital and the overnight capital costs is shown in Appendix A, is mainly driven by these assumptions:

1. The project development and construction duration is 9 years.
2. The initial 4 years of development, (Pre-FID) are funded through only equity contributions. The blended cost of equity pre-FID is 20%, nominal.
3. For simplicity, at the financial investment decision (FID), between the 4th and 5th year, the project is treated as if it is sold at a fixed value, including profits.
4. The last 5 years of the project (Post-FID) The debt-to-equity ratio is 80/20
    a. The average interest applied to expended project loan funds is 5%
    b. The blended cost of equity during construction is 14%, nominal.

The costs are spread across the 9-year timeline as described in Appendix A. The net effect of the timeline assumptions is that the Cap Ex costs would be 30.8% higher than the overnight capital costs.

For the purpose of building the LCOE, the project is treated as if it is sold at COD (even though it may not be). At that sale all profits on the equity contributions during construction will be realized, and go into the sale price. That price, in turn, is considered the capital cost when analyzing the LCOE over the project's life. In reality, it may be that the project is not sold at COD, and the equity shareholders keep their equity stake throughout the project life. In that case, they would realize profits by charging prices for power that are above the costs. The sale at COD assumption simplifies the analysis for illustrative purposes, and gives a clean figure for "CapEx". It also aligns with the analysis conducted by Lazard, which includes equity returns in it's LCOE. Post COD, there is still a presumption that the debt to equity ratio starts at 80/20, and that the equity players are earning 14-16% returns from the sale of power, so they may well be the same equity players from before COD. Like the pre-COD analysis, post-COD, the profits are built into the LCOE, instead of left as a possible premium on price over costs, to align with the methodology used in Lazard. This LCOE does not consider the cost of taxes, nor does it consider the benefit that can be realized from the Bonus Depreciation. While the cost of taxes may increase the LCOE, the bonus depreciation allowed under the One Big Beautiful Bill Act of 2025 will offset that by allowing the owner to depreciate the asset in the first year.

In Table 2, the costs of owning a nuclear power plant are converted into the Levelized Cost of Energy (LCOE) assuming a 30-year project life. For the LCOE analysis, the assumptions that are sourced from the above discussion are shown in red: 1) the OCC price range 2) the 30.8% CapEx to OpEx ratio calculated in Appendix A, 3) the debt-to-equity ratio and rates described in Appendix A and above and 4) the range of possible ITC values and their monetization discounts, described above. The orange cells represent the inputs that were reused from Lazard's 2025 LCOE+, "high" case,[44] which were drawn from data from existing, operating Nuclear Power Plants.

Table 2: Levelized Cost of Energy for New Nuclear, assuming a 30-year project life

	Low	Medium (per App. A)	Medium (Per EDF)	High
Capacity Factor	92%	92%	92%	92%
OCC rate ($/kW)	$6,200	$7,000	$8,300	$11,000
Cap Ex Rate ($/kW)	$8,110	$9,156	$10,857	$14,388
Investment Tax Credit	30-50%	30-50%	30-50%	30-50%
ITC monetization cost	10%	10%	10%	10%
Equity %	20%	20%	20%	20%
Equity Return (nominal)	14%	15%	15%	16%
Project Lifetime	30	30	30	30
Debt Interest Rate	5.0%	5.0%	5.0%	5.0%
Variable O&M Rate ($/MWh)	$5.15	$5.15	$5.15	$5.15
Fixed O&M ($/MW-yr)	$136	$136	$136	$136
Fuel cost ($/MWh)	$8.88	$8.88	$8.88	$8.88
LCOE at 30% ITC	**$76**	**$82**	**$92**	**$114**
LCOE at 40% ITC	**$83**	**$91**	**$102**	**$127**
LCOE at 50% ITC	**$90**	**$99**	**$112**	**$141**

To compare these figures to other energy technologies, the results of the LCOE analysis above were overlain on the Lazard LCOE+ unsubsidized analysis from 2025 in Figure 8. Because coal, gas, and starting in 2027, solar and wind, are ineligible for the ITC, this is a fair comparison. These LCOE's may be slightly higher than reality, however, because according to new guidance from the EDF, new coal and gas may be eligible for Title 1706 financing and storage remains eligible for the ITC. Lazard's analysis does include nuclear, but it uses a higher OCC (based on Vogtle), excludes the effect of the ITC subsidy, uses higher debt interest rates, and assumes a higher equity stake (40%) compared to the above analysis (which assumes a loan from EDF is feasible). These assumptions resulted in a significantly higher range for nuclear energy LCOE in Lazard, compared to the analysis done herein.

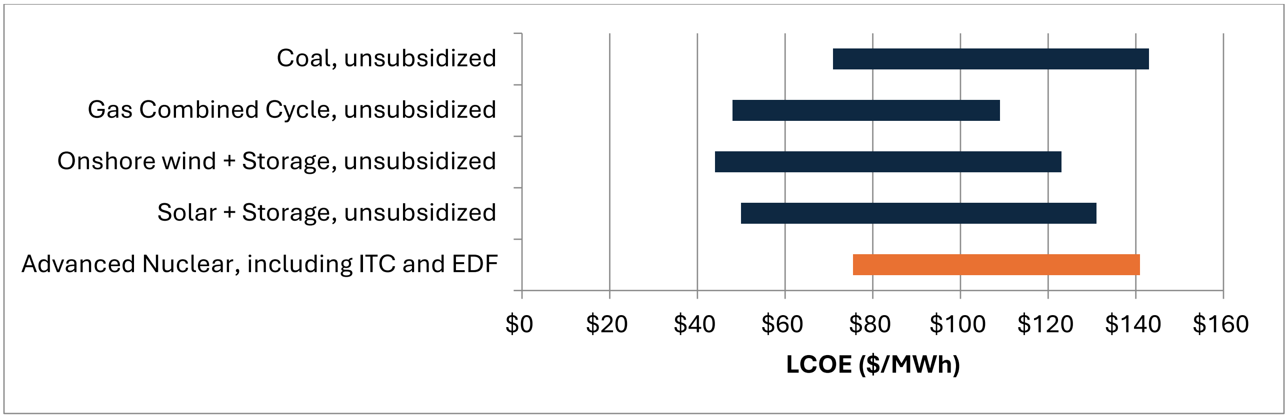

Figure 8: Nuclear Energy LCOE per above analysis, overlaid with Lazard's 2025 LCOE for unsubsidized technologies

As seen in Figure 8, the lower end of the nuclear LCOE cost range is comparable to new gas combined cycle plants (the more efficient of the gas power plant designs). With a higher risk of cost overruns, it seems that the prices on the higher end of the range, e.g. an ITC of 30% and an OCC of $11,000, are far from being commercially competitive with gas. Therefore, projects with those starting parameters should not be considered, or should only be considered with other significant mitigating factors at play, such as a federal grant.

3.4 Cost comparisons to current nuclear PPAs

A critical piece of financing new nuclear and making the business case is securing the price at which the energy will be sold once the plant has come online. This price will determine the stream of revenue that the plant will earn throughout its lifetime and should more than offset the costs described in the LCOE. Project revenues are secured by making a Power Purchase Agreement (PPA) with a creditworthy off-taker. Even solar and wind projects that are privately financed typically require a PPA to be in place to secure financing for their build. The PPAs for nuclear are slightly different for two reasons:

1) The timeline is much longer: The PPA would likely be signed 4-6 years before the power plant comes online for nuclear
2) The risks of project abandonment are larger: Given that two out of the three nuclear projects started in the 2010-2020 time frame were abandoned (SC Summer and UAMPS), the industry still must prove itself before it is considered reliable

As discussed in section 2.1, PPAs for nuclear restarts offer an insight into the value that private off-takers are placing on nuclear power. For those PPAs, the range of $70-115/MWh means the LCOE of new nuclear in the low and medium cases are commercially competitive. While inflation is expected to increase the costs of new nuclear builds over time, the cost of energy is expected to rise by about 40%, in real terms, over the coming decade, increasing the commercial viability of nuclear even further.[45]

3.5 Cost comparison to the current cost of energy

In the two wholesale electricity markets serving Indiana, PJM and MISO, both have experienced a recent increase in the “all-in” cost of wholesale energy. The all-in cost of wholesale energy considers the cost of the energy, the capacity, and the ancillary services. It does not include the cost of distribution. In the summer of 2025, as a result in the increase in capacity prices throughout MISO, that cost spiked to an average of $92/MWh, compared to $35/MWh and $33/MWh in the summers of 2023 and 2024, respectively.[46] The summer remains an outlier, however, with prices averaging $42/MWh from January through May. Still, the high capacity prices are a result of recent changes to the MISO market, which will persist in coming years and therefore, high capacity prices are expected in coming summers as well.

Because of the long timeline associated with building a nuclear power plant, and the volatility of the wholesale market, it is unlikely that any project would be financed based on the revenues prospected from future sales of energy in the wholesale market. Instead, as discussed further above, the financing will be dependent on the project developer securing long-term fixed price PPAs with creditworthy counterparties. Nevertheless, the spiking prices in the wholesale market are putting an urgency on this issue, especially for utilities or off-takers that buy power and capacity in the wholesale market to serve their load.

4. Risks and Risk Mitigation Strategies

The business case described above justifies the investment in new nuclear and allows for a solid rate of return for equity investors. Due to the EDF’s mission to stimulate new technology deployment, the debt will get a rate of return that is below market, however, the volume of capital expended exceeds that of any current industry. So the trade-off for the debt markets will be more opportunity to place debt at consistent returns while allowing nuclear prices to stay competitive as the industry rebuilds. The next hurdle for attracting investors to a project is assuring them that the assumptions in the business model are reasonable and any deviations from the assumptions can be managed and contained. Where there are high risks, investors will expect higher returns. When structuring the financing for any project, the risks will be shared among constructors, owners, lenders, suppliers, and at times, future off-takers. Assigning each risk to the appropriate party and ensuring the returns they receive for taking on those risks will vary in structure for each project. In this section, an outline is provided for the risk types and the best practices for mitigating those risks. The next section discusses the players that may take on risks at various stages throughout the project development process, though risk-sharing methods are far from standard at this phase in the industry’s maturation.

4.1 Cost overruns

Components of Cost

To understand how to manage the risk of cost overruns, consider the breakdown of the costs, as shown in Figure 9.[39]

The cost of the nuclear steam supply system is only 12% of the total cost, as shown in Figure 9. While some of the other categories also include work that is particular to building the nuclear power plant, the costs are largely driven by work that is not nuclear in nature. From EPRI:

"...the direct cost of the nuclear island was found to be less than 20% of all direct costs (i.e., 80% of on-site labor, on-site materials, and offsite manufacturing are for components in the balance of plant). Therefore, the perception that only the NSSS reactor hardware cost that must come down to make nuclear competitive, is not correct; significant savings should also be pursued in the balance of plant."[47]

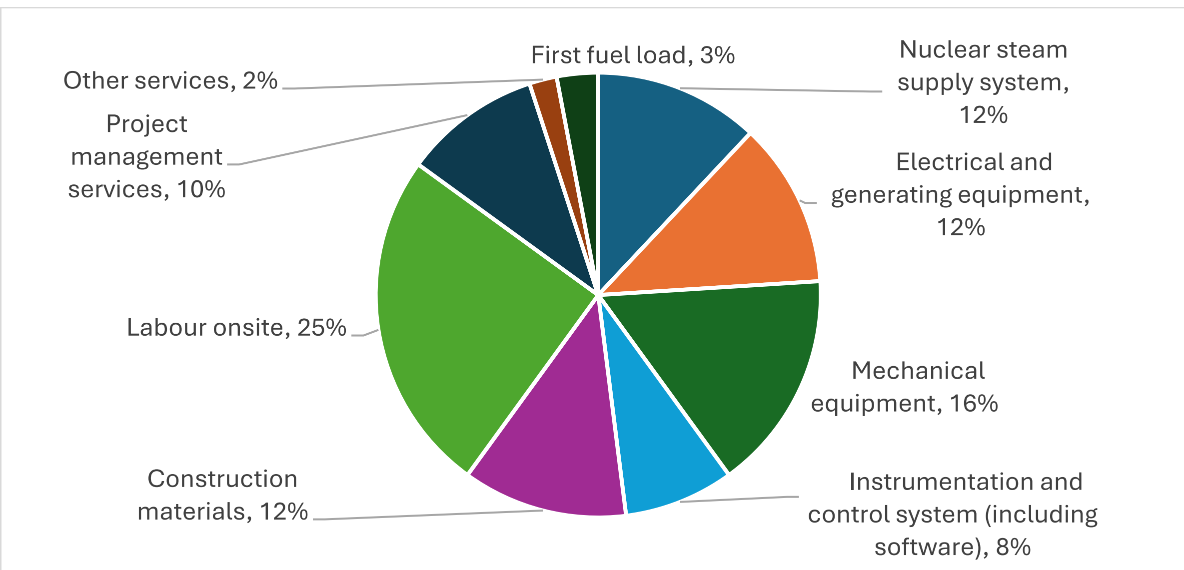

Figure 9: Cost Breakdown by Category

The risks associated with building a new nuclear reactor, particularly the supply, licensing, and the construction of the reactor do contribute significantly to the schedule risk, which in turn affects the cost risk. Still, that points projects down the path of managing schedule risks above all else in order to contain both direct costs and construction financing costs. Also from EPRI:

> *"The most significant cost reduction strategies found were those that were able to reduce construction duration, in addition to the savings in labor and to a lesser*

extent, the savings in materials. These savings are further amplified when accounting for reduced interest costs." [47]

Best Practices for controlling costs for FOAK, lessons from Vogtle

After the construction of Vogtle, which was completed far above the original cost estimates, the Loan Program office summarized the lessons learned[37] to avoid such events happening in the future:

- Complete Design
- Constructability Review
- Detailed Schedule Planning
- Clear and Consistent QA/QC standards
- Ongoing risk assessments
- Invest in intensive workforce training

The EDF notes that because the design was incomplete, perhaps only 5% complete when the original cost estimates were made, the changing cost was in part attributed to cost underestimation and not just cost overruns.

Sharing Cost Risk

One important way to control risk is when project owners strategically share risk with suppliers and EPC firms. For a project developer, they can place all the risk on the EPC firm or technology development firm if those counterparties are creditworthy and willing to accept fixed price contracts. However, the size of these companies compared to the size of a new nuclear project often means that they either cannot provide a fixed price contract, or that if they did, a failure to meet that contract would be met with potential company bankruptcy. During the Vogtle project construction, the prime contractor went bankrupt and thus, the fixed-price contract that they began with, did not protect the owners from the cost overruns. Price mechanics (including incentives to build the project at or below the target cost and penalties associated with cost overruns and schedule delays) are ways to share the risk with the EPC firms and technology providers without asking them to shoulder the entirety of the cost overrun risk.

There are other ways to share risk as well:

1) **Multiple Owners:** In early projects, risk sharing is often accomplished by having others take on a minority equity stake. This was the case with Vogtle, where multiple utilities came together as co-owners to build the project.[48] This was also a strategy used by the UAMPS project. UAMPS was a special-purpose entity (SPV) to develop the Carbon Free Power Project in Utah, backed by several utilities across 6 states.[49]

The UAMPS project was ultimately abandoned when the cost estimates began to rise, and the project failed to meet its subscription limits for power.

2) **Share non-recurring development costs:** Cross project collaboration can reduce risk by having multiple projects co-invest in the cost of non-recurring engineering, such as design finalization. One instance where costs were shared across projects is the consortium between TVA, OPG, and Synthos Power. Each project had planned to buy a GE-Hitachi BWRX-300, and each contributed to the cost to finalize the design and ready their documentation for regulatory filings.[50]
3) **Leverage percentage-based incentives and programs:** Projects that leverage the federal government incentives that are based upon percentages of total actual costs are sharing some of the risk with the federal government. For example, if a project qualifies for a 50% ITC, and it experiences a cost overrun, half of the overrun costs will be payable by the ITC and are not a risk that the equity financiers are subject to.
4) **"Buyers Club":** In early projects, there may also be cross-project collaboration to share the costs and risks associated with building the first-of-a-kind project. The Nuclear Scaling Initiative has proposed the creation of "buyers clubs" among new nuclear project development teams to share FOAK costs and FOAK risks among various projects.[51] This model has not yet been executed.
5) **Cost overrun insurance:** Finally, many in the community, particularly the Nuclear Scaling Initiative, advocate for the creation of a cost stabilization facility, also at times referred to as cost overrun insurance.[51] This would likely need to be funded by the federal government, though advocates such as NSI propose that the private sector may be able to create such an insurance instrument if they can diversify sufficiently among projects and technology types. Notably, there are no private players publicly considering a cost stabilization facility at this time. Likewise, the government has stated that the incentives in the ITC and the Loan Program Office should be sufficient to derisk new nuclear projects. As such, the federal government is not considering creating cost overrun insurance at this time.[52]

Avoid Risk Where Possible

The key risks of building the new nuclear reactor (including design issues, constructability, licensing issues, supply chain issues, and workforce issues) can be managed using lessons learned from Vogtle and creating an environment that incentivizes integrated project teaming. A large portion of risk can be controlled by minimizing project development risks associated with other decisions throughout the project lifetime. Some possible decision points that can minimize risk include:

1) **Site Selection:** Early advanced nuclear projects should minimize the risk of licensing issues by picking sites that do not require any special NRC exceptions. Sites should minimize the risk of cost overruns by finding geological conditions that are easy for construction and well understood. Sites should minimize the risk of community pushback by seeking locations where the local population and authorities-having-jurisdiction, including the state, county, and local governments, are supportive of new nuclear and value the benefits the technology can bring. Using sites with existing geological data or NRC approvals can reduce risks of early development efforts as well.
2) **EPC Selection and integrated project teaming:** Projects should select an experienced, capable, and reputable EPC firm that has teamed early on in the nuclear development process with subcontractors and other trades that are capable and familiar with the designs and complexity of nuclear construction. This will minimize the risk of cost overruns, through proper material procurement, staff availability over the life of the project, and familiarity with the particular designs/nuances of each nuclear technology.
3) **Leverage Existing Nuclear Supply Chain:** Projects, or the technology vendors that are chosen by projects, should leverage the existing nuclear supply chain and experienced nuclear workforce where feasible to ensure continuity between the existing fleet and the lessons learned by those manufacturers and the new fleet.
4) **Technology Due Diligence:** When working with a nuclear technology company with little or no project history, the project team should engage in in-depth technical due diligence of the company. During these efforts, third-party evaluators visit the manufacturing and engineering facilities and conduct interviews with the engineers and technicians working on the project. Such efforts tend to uncover issues that may not be easily noticeable from the outside, and that may compromise the likelihood of success of the new technology and the project it is meant to support.

Buy a smaller reactor

Because the total price of the SMR is smaller than the total cost of a traditional reactor, cost overruns are likely to have a smaller total value and therefore have a lower inherent risk profile. Also, the smaller size and modularity of the SMR designs promise to move more of the work from the site to the factory, which provide more continuity to procurement activities, lower field labor requirements, and enhance schedule performance. Figure 10[37] below, from the EDF, illustrates this effect. According to the analysis from the EDF, SMRs will be more expensive on a per kW basis, but their smaller overall size and cost help investors limit their total risk exposure. Because there are not yet many completed advanced reactors, it remains to be seen if the costs of SMRs will be higher or smaller on a per kW basis. It may be that the ability to move work to the factory, and the ability to control the schedule more tightly due to the modularity of the design, may ultimately lead to lower costs for SMRs on both a total and normalized basis.

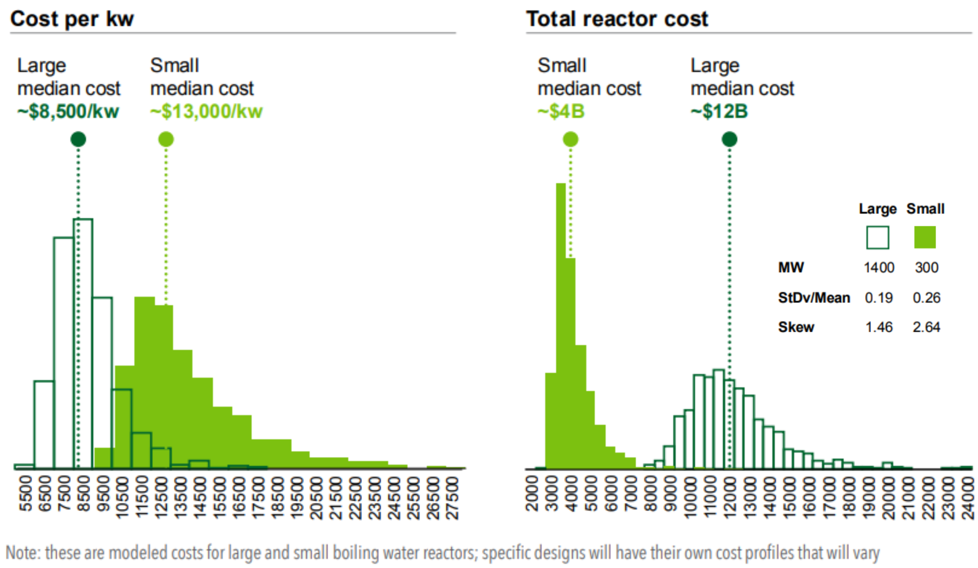

Figure 10: Probability Distribution of Project Costs

4.2 Off-taker Risks

The off-taker risk can be (and has been) managed in previous PPA-backed financing packages used to construct wind and solar. The management of a PPA risk includes:

- Providing few outs for the off-taker
- Associating appropriate penalties for any changes to the PPA, and
- Working with credit-worthy counterparties, or, absent creditworthiness, wrapping the counterparties' claims with third-party insurance.

For nuclear power, the lessons from the PPA agreements of other privately funded power projects can be applied. The major difference in off-take risk with nuclear is that, because the COD is 4-6 years after PPA negotiation, there is more opportunity for the PPA off-taker's situation to change. That said, with long interconnection queues in MISO and PJM in recent years, many projects have taken 5 or more years to get approved and PPAs have continued to be signed, and investors have continued to back projects based upon those PPAs.

Utilities in Indiana are also seeking ways to ensure that the load they are planning for will show up as they expect it, in particular, large load customers who are making service connection requests in their territory. In an agreement, approved by the IURC in February 2025, new large load customers in AEP territories must commit contractually to purchasing the power they are requesting for at least 12 years. These large load customers can reduce their contract capacity by up to 20% after the first 5 years, if giving AEP written notice of 42 months, but remain on the hook for at least 80% of their original request for the remaining 7 years.[53] In this way, AEP is protecting itself and its ratepayers against building out new generation to serve load that never arrives. In May of 2025, Indiana's House Bill 1007 was signed into law, which gives the IURC the regulatory framework to allow them to review utility's proposals to build new generation for large load users. The aim is to ensure, statewide, that ratepayers are protected from costs resulting from new generation builds that primarily serve a single large load customer, particularly if that new load was speculative or simply never materializes. Ultimately, under this regulatory-based financing structure, it would be the IURC that approves or denies the expenditure as prudent. These signals of new load is coming, add a layer of justification that the IURC may use when they are trying to determine the validity of the need; in this way, it is analogous to the way a PPA can influence a financier's decision in a privately financed project.

4.3 Risk of project abandonment

Controlling costs is one of the best ways to stop project abandonment. The two projects cancelled in the last decade, UAMPS (cancelled in 2023) and V.C. Summer Expansion (cancelled in 2017) cited cost overruns as the primary reason for abandoning the project.[54],[55] In addition to cost containment, project abandonment risk can be managed by:

1) Working with reputable developers with commitment to project success
2) Understanding that early-stage development will likely have the highest abandonment rate and investing in a strategic portfolio of early development sites and teams.
3) Ensuring committed financiers and owners have a clear understanding of the risk and the points at which they should and will abandon a project.

Projects may also be abandoned if the policies change in a way that affects the business case or project risks. While nuclear incentives and policies have been consistent over the past 8 years, past shifts in public opinion and policy shifts have plagued the industry. For example, analysis of the cost overruns at Vogtle cited the changing regulations post Fukushima as one factor that slowed down the effort, caused last-minute design changes, and added to the costs.[56] The Fukushima incident led to policy changes in Germany that shuttered open plants as the country temporarily shifted away from nuclear energy.[57] Better integrated passive safety measures and the policy consistency that comes with it continue to be important to sustaining the nuclear renaissance underway today.

4.4 General risk management practices

Throughout the project, risks can be managed through formal risk management processes. Decision stage gating, as described in the next section, further allows risks to be managed and right-sized to the current phase of project development. The stage gates give opportunities for parties to shift their investment exposure and bring on additional partners so that risks can be shared in a way that makes sense for the phase of the project.

5. Financing stack by phase

5.1 Equity Players

The equity ownership model of new nuclear can take many forms and may change throughout the project development.

1) A new nuclear project may follow a traditional development path where a utility develops the project to serve their own load, builds the project using ratepayer funding, and then continues to own and operate the project over its useful life. This same model could be followed by a consortium of utilities. Today, given the risk associated with nuclear power plant development and the fear of burdening the ratepayers that fund them with cost overruns, public utilities may not want to use the traditional model of solely financing the power plants.
2) Advanced nuclear may be developed in the same way many wind and solar projects have been developed: by a developer. In this model, the developer is the project owner. There are points in the process where the developer may transfer ownership to another developer or owner or take on additional investors. After the project comes online, e.g. the Commercial Operation Date (COD), the developer may:
    a. Continue to own and operate the plant as an Independent Power Producer (IPP)
    b. Sell the plant to a utility or another IPP at a pre-negotiated, contracted rate through a "Build Transfer Agreement"
3) New projects may be developed by a special purpose vehicle with a majority shareholder, and one or more minority shareholders that have some stake in the outcome of the project. The majority shareholder would be the developer or utility. Example minority shareholders include:
    a. Site Owner: During early development, a site owner may have a minority position, allowing them to gain returns on the project and incentivizing them to conduct the necessary studies on their site with rigor and efficiency.

b. Strategic Investors: At an early (or any) phase, strategic investors such as green funds or nuclear-focused funds may want to participate as a shareholder. This will give the project an opportunity to share risk and will provide those investors with a way to build a portfolio unique to their mission.
c. Project Stakeholders: In the later development and construction phases, minority investors may include the project energy off-taker, the EPC firm building the project, or the nuclear technology vendor providing the reactor technology. Incorporating such minority positions helps align incentives, though if pricing mechanics are used in the contract with the EPC or technology vendor, having them also take a minority stake may be redundant.
d. Motivated Off-taker: A motivated off-taker may be able to participate as an equity shareholder to encourage the buildout of a project that they need to serve their load, using a technology that they are interested in and believe will succeed.

This model also allows ownership to change hands at key project milestones or for additional investors to join or leave the project as required.

5.2 Debt Financing

Debt financing begins after the development phase is complete. The development phase ends, and the construction phase begins once the key milestones have been addressed and the financial investment decision has been made:

1) Permitting, including NRC construction license, is received
2) Contracts with suppliers, including technology suppliers and EPC firms, have been agreed upon. Critical subcontractors may also be expected to be under contract.
3) Off-take PPAs, or Build Transfer Agreements have been negotiated
4) The interconnection agreement is in place

Besides this, a clear project schedule and plan should be in place. The debt financing parties will conduct a due diligence process to secure their investment, and the team is expected to have addressed any findings from that process before the investment decision is made.

Debt financing, at this early phase of the industry, will be provided by the Loan Program Office or structured private debt, a topic which was discussed at the Nuclear Power Summit on Sept 24, 2025:

"Big Banks are not relevant to this space at all from a lending point of view. The regulatory lending requirements do not allow for project lending especially in this country... So, in the end it's the structured private debt markets that would step in above and beyond the EDF, or in place of."[58] - James Shaefer, Gugenheim Securities

"None of them (the big banks) will be doing financing in the foreseeable future, but the EDF will be doing financing for the next few years."[52] Julie Kozeracki, Loan Program Office

Loan guarantees from the EDF can cover up to 80% of the total project costs and provide debt financing at an interest rate of the 10-year treasury bond rate plus 0.4-2.0%, depending upon the riskiness of the investment, as described in Appendix A.

5.3 Other: Grants and In-Kind Support

Federal Grants to support FOAK builds have been awarded to advanced reactor vendors to build and develop their first projects under the DOE's Advanced Reactor Demonstration Project (ARDP).[59] This is part of the funding behind the Kairos Hermes 1 and Hermes 2 reactors, currently under construction, and the TerraPower Natrium reactor, also under construction. The DOE released another award to assist in the development costs of a Gen III+ light water reactor SMR design; however, those awards have yet to be announced.[60] It is likely that at least one project will be awarded $400-800 million to build one of the four eligible light water reactor SMR designs: Westinghouse AP-300, Holtec SMR-300, GE Hitachi BWRX-300, or Nuscale's US600. No further grants have been announced.

Consortium Partners or Technology Vendors: When it comes to the FOAK project, a large part of the early development costs is the cost to prepare and submit the license application to the NRC. For the portion of the application that ties to the technology design, the vendor may be asked to complete that work on their own dime.

State grants: Some states have set up development funds to assist in early-stage development costs and attract nuclear projects to their state.

- Kentucky: $20 million toward nuclear development, $10 million in grants[61]
- Texas Nuclear Energy Program Fund: $350 M to plan, assess and launch projects[62]
- Wyoming Energy Matching Fund: $155M to fund pilot or commercial projects
- Tennessee: Grant funding, adjacent to project deployment (Nuclear Energy Fund) and project-specific grants (Clinch River Project)
    - Adjacent funds 2023-2024: $50 M for supply chain investments
    - Adjacent funds 2025-2026: $26.2 M to support education and research
    - Project specific: $50 M SMR grant to the Clinch River project.

- Nebraska: Nuclear & Hydrogen Development Act Fund
    - Project specific grant, $1M to site reactors near their existing reactor, and Adjacent support for workforce.

5.3 Phases of Development and Financial Stacks

Ultimately, the financing stack is more of a menu of possibilities than a clear and distinct path, as seen in Figure 11. The sections below outline how the phases of development may be financed throughout the project for a 300 MW SMR. More detail is in Appendix A

Early Development: The first year or two of early development includes conducting early siting studies, identifying technology and EPC partners, and contracting with those partners. Those two years will cost about $12 million. In roughly the third year, the costs will grow to about $75-120 million as the project prepares and submits its NRC license application and interconnection application. In the early development phase of the project, there are likely only one or two parties involved, one of whom is the project developer or utility. If the project is developed by a developer who is not an expert in nuclear power or has limited staff/financial resources, it may exit the project (during or at the end of this phase) and sell the project to a more resourced or more nuclear-focused developer.

Later Development: Later-phase development will happen in parallel with the NRC's license application processing. Later development activities include all of the planning and due diligence required to secure the financing, including the PPA or BTA negotiations, and all of the planning and engineering required to construct the power plant. As described in Appendix A, some early procurement activities and pre-nuclear construction activities can overlap with the second year of the late development phase. That does require securing construction financing earlier, and nearly doubles the costs in this phase, but is the only way to keep the schedule down to 3 years of construction.

Construction: This is the most expensive part of the project, costing $1.3-2.0 billion for a 300 MW plant. At this phase, equity financing is now supported by debt financing. If using the EDF, debt financing may cover up to 80% of the total project costs. The equity shareholders may grow to include additional shareholders, either to cover growing costs or to bring on additional shareholders and assure aligned interest in the project's success. For example, the EPC vendor may join as a shareholder at this phase, to assure they have aligned incentives in the project's success.

	Early Development ~ 3 years	Development ~ 2 years	Construction and Startup ~4 yrs	NPP 40-80 year life

Equity	• Majority Investor (70-10%)
	  • Developer or SPV
	  • Utility (or consortium of Utils.)
	• Minority Investors
	  • Private investor with a stake in future project. (e.g. off-taker, site owner)
	  • Small strategic investors
		• May add other early and strategic investors	• Majority Investor
			  • Developer or SPV (50-100%)
			  • Utility Owner (50-100%)
			• Minority investors such a: the EPC vendor, technology vendor, key/critical off-taker, financial investors or previously mentioned minority owners.
				• Owner or co-owners and operators will re-consolidate

Debt	• None	• None	• Debt up to 80% of project using EDF as a guarantee. May use Treasury for debt. • Structured private debt financing which may include: Infra funds, sovereign wealth funds, and other private debt financiers.	
Other	• States with a Nuclear Development Authority may leverage those here. • DOE Award, such as Gen III+ SMR Tier 2 awards.	• 2 DOE cost-share awards have been issued in the past that cover later-phase development and construction: ADRP, Tier 1 Gen III+ SMR Tier 1. • In-kind support from technology vendor, especially for FOAK non-recurring costs.		

Figure 11: Finance Options by Project Phase

Operations: After COD, the project will go to its long-term owner and operator, which may be separate entities, but historically have often been the same. If the project had negotiated a BTA with the final owner, the sale of the project will happen at COD according to the pricing described in that BTA. If the original developer will continue to own and operate the plant as an independent power producer, and if they have taken on minority shareholders throughout the development, they will likely consolidate the project into a simpler structure, as there are fewer reasons to maintain a complicated ownership structure post COD. Finally, if a utility built the power plant for their own purposes, they will continue to own it post-COD. The debt payments will begin after COD, but the debt will remain outstanding until it is paid off according to the terms of the agreement. The ITC will be applicable after COD, which will result in a lot of the original costs, 30-50% of the total project costs, being taken off the eligible project's books.

6. Developer Types

In the early phases of development, an important player involved in the project is the developer. It is critical, therefore, to understand this counterparty as a way to inform their due diligence of the counterparty and the project. Because the term "developer" is open-ended, and because their funding comes with its own strings attached, based on its source, it is worth describing the various flavors of developers that are emerging in the marketplace and what the pros and cons are to each type.

Firstly, the traditional method of financing new nuclear using utility rate payer dollars is certainly a possibility. The benefits of a self-developed project developed, constructed, and ultimately owned by the utility are that the model is simple and the utility has a long-time horizon that allows it to invest in projects that take many years to build. The downside of utility funding is that the risk of cost overruns falls to the ratepayers.

A sample of the privately funded developers are outlined in Table 3. Some of these developers have made public announcements regarding their company's interest in nuclear development, and others confirmed their interest and backing via email correspondence.[63]

Large, publicly traded developers, including Constellation, NextEra, and Vistra, have the advantage of having large balance sheets, deep nuclear operational expertise, and a deep bench of experts that can be called upon during project development. The con of working with these larger companies is that they may be less agile due to their size and their requirement to answer to their shareholders. Their size may also help them to find ways to

Category	Example Companies	Technology	U.S. New Nuclear Projects	Notes
Large Publicly Traded Developers	Constellation	Agnostic	2 SMRs @ Existing NPP	All three also have operating Nuclear Reactors and significant energy infrastructure development experience.
	NextEra	Agnostic		
	Vistra	Agnostic		
Start-up Publicly Traded Developer	Fermi America	Westinghouse	4 GW in Texas	Data center and NPP co-development
Startup, VC-Backed Developers	Elementl	Agnostic	3 projects with Google	
	The Nuclear Company	Agnostic		
Startup, PE-Backed Developers	Entra1	NuScale	6 GW with TVA	
	Nvision Power	TerraPower		
	Others e.g. ANA, Solestiss	Agnostic		Various other small, PE-backed Developers with services arms
Technology Developers, self-developing projects, VC-Backed	Blue Energy[64]	Blue Energy		Reactor vendors that are self developing and provide financing through their partners. Also provide EPC services. E.g. "Turn key"
	Last Energy[65]	Last Energy	600 MW in Texas	
Mid-size Solar Developers, PE backed	TBD	Agnostic		Some interest from mid-size solar developers, but none have made public announcements yet.

Table 3: Privately-Funded Nuclear Power Plant Developers

spread their risk across multiple projects, which, while helpful to the viability of the company and the nuclear industry, may make them less invested in the success of each individual project.

Startup, VC-backed developers, like Elementl and the Nuclear Company, have the advantage of being small, agile, and tied specifically to the development of new nuclear projects. Because they are funded by venture capital, the risk profile of their backers aligns well with the novel nature of new nuclear technology. One downside is that venture capital funders tend to expect returns more quickly than private equity, where sometimes the development of a new technology requires patient investors.

Startup, private equity-backed investors have a few flavors of their own. Some smaller companies are being established specifically to serve the early development market with private equity dollars. Two others are tied to specific technologies that they partner with. The upside is that they are small and agile and have funders with longer time horizons than VC.

Some very small microreactor companies have opted to become vertically integrated, promising to develop, build, and even own their own systems. The pro of this model is that it takes all the risk off the off-taker. The project is fully funded, and the risk is fully absorbed by the technology developer. The downside is that these are small companies, backed by venture capital, which may not be able to deliver the projects reliably.

Finally, some mid-size solar developers have expressed, anonymously, that they may be able to do early development of a nuclear reactor. The benefit of these developers is that they have an excellent history of forming close and cooperative relationships with community members, and they have been leaders in novel financing mechanisms required to bring new technology to market. Besides having been financiers of solar before it was low-risk, many have also developed Battery Energy Storage projects throughout that technology's development and maturation. They also tend to be agile, well-funded, and able to act quickly. The downside is that they lack nuclear development experience.

7. Recommendations

Recommendations for the state of Indiana to accelerate the development of new nuclear in the state include:

1) State support may be helpful to kick-start early development. While the risks of project development are highest at the beginning, the barriers to entry are the lowest. Therefore, funding or in-kind support to help qualify a portfolio of sites and partners that are interested in early-stage development will enable the ongoing development of some subsets of that portfolio.
    a. Prioritize working with credible partners, where such partners exist.
    b. Find innovative ways to provide in-kind support through in-state connections, technical assistance and creating spaces for collaboration and acceleration.
2) State and utilities should be working to collaborate with other parties and other states to share and reduce risk:

    a. Already, IOED is part of the National Association of State Energy Officials "First Movers", which should create opportunities for shared learning, collaboration, and shared risks.
    b. The state should continue to increase its engagement with that and other similar groups when they propose joint actions (RFPs, teaming agreements, etc.) to ensure Indiana is part of the action-oriented collaborations.
    c. The state should engage with the national labs for technical support to maximizing the benefits of the federal government for early movers on new nuclear siting and construction.
3) State stakeholders should each play their role in finding and forming projects that minimize all risks besides the unavoidable risks of deploying a new technology
    a. Complete, thorough due diligence with tech vendors and EPC firms
    b. Pick sites, partners, off-takers, communities, etc., that don't raise risks.
4) The state should find ways to leverage all assistance and incentives from the federal government that exist today, and those that are available in the future. Notably, the federal government has recently announced $80 Billion in funding to support the buildout of AP1000's, that the state can work to secure in Indiana.
5) The state should carefully and continuously weigh the upsides and downsides of moving quickly through rigorous engagement with industry stakeholders. If the state is taking on the risks of FOAK technology, it should leverage those risks to negotiate supply chain benefits, workforce upskilling, and partnership risk-sharing as feasible.

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Appendix A

Indicative Cost and Schedule

Overview

The following indicative schedule and budget was developed using existing resources and interviews with stakeholders. The purpose of this budget and schedule is to:

1. Show the overall, phased cost of developing a new advanced nuclear power plant
2. Calculate the ratio between the overnight capital cost and the capex, which incorporates construction financing costs and owners' costs (including owners' expected rate of return for early development efforts)

Developing the approximate timeline for a nuclear power plant requires estimations, each of which are outlined below. The timeline and budget used (shown below) are relatively tight for a first-of-a-kind build; more in line with that of a second- or third- of a kind build. First of a kind (FOAK) costs are higher (and schedules are longer) for expected reasons, like non-recurring engineering and licensing costs, but unexpected issues with design constructability, supply chain quality control and workforce readiness also contributed to high FOAK costs and construction delays.[1] As more projects are built on-time and on-budget, and as costs normalize, these estimations may be replaced with actuals, where such information is made public. Furthermore, as more projects are built and risks decrease, the expected rate of returns required by investors may diminish.

The construction debt modeled here assumes that the project is financed by the Energy Dominance Fund (EDF), formerly the Loan Program Office (LPO) under the terms of the Title 1703 program that was in place in early 2025. Loans will now be made under Energy Dominance Financing (EDF), Title 1706, for which nuclear power plants are eligible, but which have not yet published standard terms. For the former program for which nuclear power plants were eligible, Title 1703 Innovative Energy Program, LPO lent money at the 10-year treasury bond rate, which has averaged 4.3% from January through November 2025[2], plus a 0.375% liquidity spread, plus up to 1.625% for a risk-based charge.[3] The risk-based charge is a function of the credit rating of the borrower.

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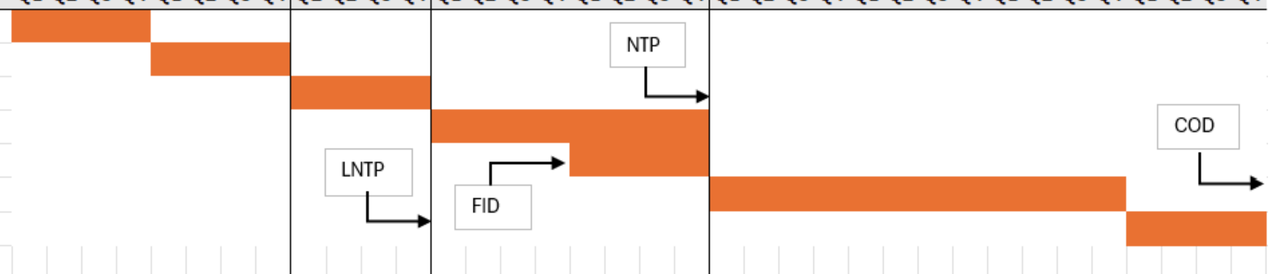
Assumed schedule and budget, by year for this analysis

Assumptions	
Size:	300 MW
OCC ($/kW)	$7,000
Equity Early Development R(	20%
Equity Construction ROI	14%
Debt Interest Rate	5.0%

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Project Development Timeline (300 MW)	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4
Pre-Development: Partnership Site selection									
Early Development: Contracting & Siting Studies									
Development: NRC submission, Int. App & PPA Financial DD									
Development: Planning, NRC eval/supp. & Int Agree.									
Early Construction: Non-Nuclear Cons., early procurement									
Construction & Procurement Costs									
Operational Liscense/Fueling/Startup/COD									
Annual Investment	$0.9	$11.1	$103.0	$30.0	$355.0	$465.0	$465.0	$465.0	$205.0
Cummulative Investment (Cash Basis, EOY)	$0.9	$12	$115	$145	$500	$965	$1,430	$1,895	$2,100
Equity	100%	100%	100%	100%	20%	20%	20%	20%	20%
Debt	0%	0%	0%	0%	80%	80%	80%	80%	80%



Outputs	
Total OCC	$2,100 MM
Total Cap Ex	$2,750 MM
Cap Ex to OCC rate	30.8%
Financing Pct of Total CapEx	23.5%

With a BB+ rating, the total interest rate spread (liquidity charge risk-based charge) would be 0.7%, for a total debt interest rate of 5%.[4] IOU's and generation cooperatives in Indiana and large, established developers like NextEra, Constellation and Vistra have credit ratings of BBB- or better, so assuming a credit rating of BB+ is conservative. Under Title 1703 LPO lent up to 80% of all eligible project costs,[3] which was assumed to still be the case with Title 1706 under the EDF.

The overall overnight capital cost assumed for this exercise is $7,000/kW. This is 13% higher than the LPO assumption for a "best practice" first-of-a-kind build in their 2023 reports[5], but 16% lower than the cost they listed in their 2024 report as the expected cost of the next two AP1000s.[6] $7,000/kW is also the average across all the cases studied by INL in their recent SMR meta-cost analysis.[7] For a 300 MW system, that translates to $2.1 billion in total costs. As described herein, the pre-construction costs and the startup/commissioning costs were estimated based on discussions with subject matter experts and known estimates from recent nuclear development and cost estimation activities. The remaining costs were spread over the construction and procurement time period such that the total reached $2.1 billion.

Cost-by-phase narrative

The first three years shown above are Pre-development Year 0, Early Development Year 1, and Early Development Year 2. The first two years of development are relatively low-cost and a small percentage of the overall project cost. As such, estimations by engaged stakeholders were used where recent, citable resources were not available. In year 2 the project costs increase dramatically as the construction permit application is prepared. For this, estimates from literature for a similar permit was used.

At the end of year 3 and the beginning of year 4, this timeline assumes that the project moves from development to construction, and passes through the Financial Investment Decision (FID) gate. At this time the project is restructured or sold and changes from 100% equity to 80% debt, 20% equity. To keep the math simple, it assumes that the project is "sold" at this time, e.g. the equity shareholders don't carry through, but rather realize their profits at FID. In reality, they would not realize their profits at this gate, but likely stay on the project through COD, at least. The equity rate of return lowers to 14% from the initial 20%

[4] LPO guidance Document. Credit-Based Interest Rate Spread

[5] Kozeraki, J et al. LPO Sept. 24, 2024. Nuclear Energy Summit hosted by the Atlantic Council in NYC.

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at FID as well. This means that in year 4 significant investments begin to be made into construction costs such as down payments on the reactor, pre-nuclear construction activities and pre-construction engineering activities.

During construction, this analysis simply spreads out evenly the remaining costs over the 3 year construction timeline. It is taking as an assumption, that the whole project will stay at the economically competitive $7,000/kW, and does not attempt to conduct a bottom's up analysis of the construction phase activities nor spread them through that timeline according to any particular spending profile.

At COD, the project is then assumed to be "sold", creating a useful CapEx number that incorporates the profits of the equity stakeholders. In reality, the equity stakeholder might continue to be the owners of the project and realize their profits through the power sold. This simplification allows a calculation for LCOE, though it might be argued that the LCOE is more than just a levelized cost, but rather a levelized price that allows for sufficient returns for the construction equity shareholders. After COD, in the LCOE analysis shown in the whitepaper, the equity stake stays the same (20%) and the expected rate of return for equity partners stays at 14%, thus in reality, these may very well be the same shareholders throughout.

Cost line-item assumptions

1) **Pre-development (Year 0 - $900k)** activities include identifying and aligning on the project site and potential project partners.
    a. **Site Screening and Selection:** Studying a variety of sites, selecting a site, and acquiring basic site control (such as a lease option) are estimated to cost $700,000
    b. **PPA Engagement:** Engaging with potential off-takers and developing term sheets with each is estimated to cost $100,000.
    c. **Reactor Technology and EPC Firm Shortlist:** Creating a shortlist of which reactors technology to propose in subsequent phases and which EPC firms will be considered is estimated to cost $100,000.
2) **Early Development (Year 1 - $11.1M)** activities include moving the site toward construction licensing readiness and firming up contracts with vendors and off-take partners.
    a. **Detailed Site Studies:** Completing a critical path siting study to move the site toward licensing readiness with minimum expenditures is estimated to cost $6,000,000. This study will include the installation of a metrology tower,

preliminary core borings, hydrology wells, seismic surveys, and preliminary environmental studies.

b. **Site Control:** Assuming this model SMR requires an average sized site of 275 acres[8], and the cost per acre is $12,000, the total cost would be $3.3 million. In the real world, the site owner might use land they already own, or the stie owner might join as an equity partner. Nevertheless, this is accounting for the value of the land as if it were purchased which builds in the opportunity cost for the self-developing case or the value of the shared equity in the case that the site owner becomes and equity stakeholder.

c. **PPA Contract:** Negotiating terms of a power purchase agreement is estimated to cost $150,000.

d. **Select the Reactor Technology Provider and EPC Firm:** Issuing an RFP and evaluating, selecting, and negotiating terms with key vendors (including the EPC firm and if necessary, the reactor technology firm) are required activities in selecting project partners. The initial down-selection, subsequent in-depth due diligence on top respondents to validate their technical readiness, and vendor negotiations are estimated to cost $600,000.

e. **LPO and NRC Pre-Application Engagement:** Navigating pre-application engagement with the LPO and NRC is estimated to cost $250,000.

f. **Preliminary Local Engagement:** Performing community engagement studies and planning, local government engagement, local permitting preliminary engagement, and state government engagement is estimated to cost $800,000.

3) **Early Development (Year 2 - $103M)** activities include getting the project ready to submit the construction license application, the interconnection application, and completing the financial due diligence process to obtain debt financing. Costs increase significantly in this phase, so references for these estimates are included. Financial due diligence can spill into the next phase with relatively little impact as major procurement activities will not begin until year 4 at the earliest. The interconnection application can also spill into later years due to interconnection reforms that are reducing queue times to 1 year by 2028. Given the timing flexibility of the other actions required in this year, submitting the construction license application is the critical path activity. Putting all of these costs into year 2 is a conservative estimate of a front-loaded budget.

   a. **Financial Package Preparation:** To pass the financial due diligence, the owners must combine and analyze the contracts and selections to make a

[8] EPRI New Nuclear Siting Guide. 2022.

cogent business plan ready for review. They must also be able to respond to questions from the financial due diligence team. The cost to prepare the financial package with the documents and agreements obtained in year 1 is estimated to be $1,000,000. This is informed by the due diligence third party costs of $1-3 million (below).

b. **Financial Due Diligence, Third Party Review:** This budget assumes that the project will use the LPO process to obtain financing. The LPO estimates that these fees, payable to a third party, cost about $1-3 million.[9] The estimated costs for the purpose of this study are therefore $2,000,000.

c. **Completed Submission of Construction Permit Application:** The cost of completing and submitting the construction permit application is estimated in various studies as ranging from $50 million to $200 million[10]. In line with this published range, and based on discussions with stakeholders, this analysis assumes the total construction permit application costs will be $75 million ($6 million for year 1, and $69 million for year 2). Construction permits require the reactor designer to participate by sharing their design information, but this analysis is focused on a second or third of a kind reactor using a repeatable design. Therefore, this study assumes that the development costs for the reactor construction license will be minimal. If the reactor is a first of a kind design, license preparation will likely be on the higher end of the range, nearing $200 million. In a first of a kind situation, project owners should ask the reactor developer or federal government to shoulder some of those significant costs.

d. **Interconnection Application:** The total cost of a Generator Interconnection Agreement (GIA) in MISO is an average of $140/kW, historically.[11] Given the rising interconnection costs, and a variability among costs, this study assumed a cost of $200/kW. This timeline assumes that half of the costs for the interconnection agreement are due when the interconnection application is submitted and the project is being studied, and the other half is due at the end of the process when the project enters into a GIA. While these amounts can vary by transmission operator and other particulars of the interconnection process, this is an approximate breakdown. Given the recent changes to interconnection procedures, and the emphasis on interconnection agreements being reached in 1-2 years, it may be

[9] Loan Program Office. Title 17 Energy Financing. https://www.energy.gov/lpo/title-17-energy-financing
[10] Sinclair, "Estimated Resources Necessary to Pursue an Early Site Permit for a Small Modular Nuclear Reactor Site," Technology and Research Analysis, 2022.
[11] Seel, Joachim et al. Interconnection Cost Analysis in MISO. Lawrence Berkley Lab. 2022

conservative to assume the project will go through the interconnection process in year two, as it could be pushed out the year seven.[12] However, given the risk of high costs of interconnection, and the possibility of schedule overruns in the interconnection process, it is still recommended that projects enter the process early and not let this detail be a potential hangup in the drive toward commercial operation. The estimated outlay for the interconnection of a 300 MW plant is $60 million total, so the portion due in this year is $30 million.

e. **Ongoing community engagement:** Performing economic impact studies and workforce development planning, local government engagement, local permitting preliminary engagement, and state government engagement is estimated to cost $1 million.

4) **Development Phase (Year 3 – $30 M and Year 4 – $355 M).** Due to the U.S. Presidential Executive Order from May, 2025, "Ordering the reform of the Nuclear Regulatory Commission", the review timeline for any construction license should be reduced to 18 months by November 2026. Still, to account for delays in processing, responding to, or submitting the construction license application, this schedule assumes a 2-year gap between application submission and acceptance. In Year 3, costs will reduce significantly, as the project enters a planning and preparation phase, shepherding the construction license through the NRC. In Year 4, early procurement and pre-license construction is estimated to begin, raising costs significantly. Both expenditures (early procurement and pre-license construction) may be difficult to negotiate with financiers, as the financial investment decision (FID) point would typically align with the receipt of all permits, including the construction permit. However, to maintain the aggressive, four-year construction and startup schedule, this overlap is necessary. Therefore, this report assumes the FID happens between Year 3 and Year 4, 6-12 months before the project receives its permit from the NRC. A more conservative estimate would add a year to the schedule.

   a. **NRC Application Processing and Construction and Procurement Planning:** In Year 3, the project must supply the NRC with supplementary construction permit data and information, which could not have been collected in the one-year application preparation process (~$5 million in year 3). In Years 3 and 4, the project must pay the NRC staff $148/hour to review

[12] FERC Office of Public Participation. Explainer on the Interconnection Final Rule. https://www.ferc.gov/explainer-interconnection-final-rule

the application[13] ($7 million spread over 2 years, or $3.5 million per year). This $7 million estimate is based on a cost estimation tool put out by the NRC in 2023[14]. Unfortunately, that cost estimate did not include any construction permits, so the numbers for the early site permit (29,000 hours plus $2.76 M outsourced) were used instead. In Years 3 and 4, the project must also pay their own staff to respond to questions and generally support the application. This was assumed to cost an additional $500,000 per year, or $1 million total.

b. **Construction and Procurement Planning:** Another $30 million ($15 million per year in Years 3 and 4) would go toward the detailed planning of the construction and procurement phase and oversight of the early procurement activities. According to the World Nuclear Institute, engineering procurement and construction planning will cost a total of about 7% of the project costs, or $147 million.[15] By spending about 20% of that money before construction begins, the project will be following the best practices recommended by the LPO to plan prior to construction.

c. **Early Costs of Procurement and Non-Nuclear Construction:**
    i. The above schedule assumes that up to $100 million is spent in year 4 on procurement initialization payments, such as down payments to the reactor vendor. Assuming reactor is 10% of total costs[16], and the down payment is 50% (conservative), that down payment would be about $100 million.
    ii. According to the World Nuclear Association, site development and civil works account for about 20% of the total cost of building a nuclear power plant, in this case $420 million. Assuming that about half of that can be spent in the pre-NRC licensing phase as non-nuclear construction, $200 million is assumed to be spent in Year 4 on non-nuclear construction.

d. **Generator Interconnection Costs:** The schedule conservatively assumes that the Generator Interconnection Agreement is signed at the end of Year 4, triggering the outlay of the additional 50% of the network upgrade costs which, as described above, are assumed to be $30 million.

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[13] NRC fees. Website. https://www.nrc.gov/reactors/new-reactors/advanced/new-app/general-info/fee Accessed 10/14/2025.
[14] New Reactors Business Line Fee Estimates. NRC. https://www.nrc.gov/docs/ML2301/ML23018A174.pdf
[15] World Nuclear Association. Economics of Nuclear Power. Sept. 29, 2023. *https://world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power*
[16] World Nuclear Association. Economics of Nuclear Power. Sept. 29, 2023. *https://world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power*

e. **Community Engagement and Workforce/Supply Chain training:** This engagement, which would include public outreach and education and workforce/supply chain development program execution was estimated to cost $12 million total, or $6 million per year.

5) **Total Pre-Construction Costs, Years 0 - 4:** The sum of the preconstruction costs for this project (all of the above costs excluding site preparation and early procurement costs) is $196 million. This accounts for 9% of total costs. Comparing this to the meta cost analyses conducted by INL[17], this total is relatively high, with that study showing an average cost of pre-construction costs at 5% of the total costs. Higher upfront costs are a financially conservative assumption, as they take longer to repay and are considered higher risk therefore are subject to higher interest over the project's lifetime. Furthermore, higher pre-construction costs imply that the project will follow the recommendation of the LPO to enter the construction phase with clear, executable designs and plans instead of planning as the project is being built.

6) **Construction Phase (Years 5, 6, and 7 – $465 M per year):** Construction time is a key factor in determining the amount of construction financing that will be required. Because this study is estimating the schedule and costs of a 300 MW SMR, various SMR construction times were referenced. GE Vernova's BWRX-300 is one of the more advanced designs at this phase, with the nuclear construction phase beginning in April 2025 at their Darlington site in Canada. Non-nuclear construction began in 2022, with site leveling and component procurement beginning in 2023, and the order for the reactor placed in January 2023.[18] GE Vernova estimates their total nuclear construction time will last 24-36 months.[19] Nuscale, another SMR that has a nearly-complete design due to having been through the reactor technology licensing process, also advertised a 36-month construction timeline.[20] TerraPower has an expected total construction time of 5 years for their first project in Kemmerer, Wyoming, with two years of non-nuclear construction and three years of nuclear construction.[21] Westinghouse, a company with real-world advanced reactor

[17] Abou-Jaoude, Abdalla et al. Meta Analysis of Advanced Nuclear Reactor Cost Estimations. Idaho National Laboratories. July 2024

[18] ANS Newswire. OPG gets final permission to construct first North American SMR. https://www.ans.org/news/2025-05-12/article-7014/opg-gets-final-permission-to-construct-first-north-american-smr

[19] GE Vernova Hitachi. Darlington Ontario powers up with BWRX-300 reactors. https://www.gevernova.com/nuclear/carbon-free-power/bwrx-300-small-modular-reactor/bwrx-300-darlington-ontario

[20] Nuscale Technical Specifciation https://www.nuscalepower.com/products/nuscale-power-module

[21] TerraPower. June 10, 2024. "TerraPower Begins Construction on Advanced Nuclear Project in Wyoming". https://www.terrapower.com/terrapower-begins-construction-in-wyoming

deployment experience (having deployed their AP-1000) but with fewer milestones achieved for their SMR design (they have not received a design license like Nuscale, nor have they started construction like GE Hitachi), also expects a three-year construction timeline for their SMR.[22] This analysis uses the three years of nuclear construction time that aligns with the estimates from the four above-cited vendors. However, it shortens the period for procurement and non-nuclear construction to 1 year before construction begins, as these projects are each first-of-a-kind builds and later builds may allow for simplified procurement and pre-construction timelines.

The study estimates that the remaining $1,395 million (The $2.1 Billion total, less the above costs from years 0-4, less the below $205 million for startup/commissioning in year 8) in costs are evenly spread across the three-year construction period. This results in annual costs of $465 million. Given that no other projects are currently in the nuclear construction phase, and the finished project, Vogtle, was more than 10 years over its original schedule, there are no recent U.S.-based "actuals" upon which to improve this estimation. EPC firms and reactor vendors should be asked to estimate the required cash outlays during formal proposal processes as companies look to construct nuclear power plants. Contractors can then use those initial estimates to refine the budget accordingly.

7) **Startup, Commissioning, and Operation License (Year 8 - $205 Million).** Nuclear power plant startup, commissioning, and fuel load is assumed to last one year. For Vogtle 3, the most recently built reactor, hot functional tests began in April 2021[23] and the project came online commercially in July 2023. This implies a testing period of over two years. However, when hot functional tests began (in 2021), the tests were expected to last 6-8 weeks and the time between the successful completion of the tests and the COD (in 2023), was 2 months.[24] This schedule assumes a 1 year timeframe, significantly longer than the 4-month best-case scenario, but shorter than Vogtle's actual test and startup time of 27 months.

[22] Dalton, David. Westinghouse AP300 / US Company Unveils 'Game-Changing' Mid-Sized Nuclear Reactor. May 2023. Nucnet. https://www.nucnet.org/news/us-company-unveils-game-changing-mid-sized-nuclear-reactor-5-4-2023
[23] ANS. April 27,2021. Latest from Vogtle: Unit 3 hot functional testing begins, Unit 4 water tank placed. https://www.ans.org/news/article-2845/latest-from-vogtle-unit-3-hot-functional-testing-begins-unit-4-water-tank-placed/
[24] Georgia Power. May 29, 2023. Vogtle Unit 3 reaches 100 percent energy output for the first time. https://www.georgiapower.com/news-hub/press-releases/vogtle-unit-3-reaches-100-percent-energy-output-for-first-time.html

a. Operating License: Before startup, the plant must apply for and obtain an operating license from the NRC. This will include any customizations or changes that were incorporated as the design was built, and if the design has not yet been built at all, will incorporate all of details of the reactor design. This activity is estimated to cost $100 Million.
b. The World Nuclear Association estimates the cost of commissioning the plant, and doing the first fuel loading to be 5% of the total project costs[25]. Using that estimate, the commissioning costs for this project amount to $105 million.

Rates of Return and Interest Rate Assumptions

The following assumptions were used to convert annual cashflows into total capital expenditures. In this case, the study assumed the equity rate of return for upfront development costs was higher, in line with the riskiness of early investment in a long-lead-time project with limited commercial deployment experience, e.g. 20%.[26] However, this analysis kept the equity rate of return for construction and operations to 14%. The debt construction financing rate is shown at 5%, as described in the report, due to the expectation that the project will receive EDF debt financing at the 10-year treasury bond rate plus a 0.7% spread. Additionally, assuming EDF debt financing allows the debt to be 80% of project costs starting in Year 4, a significant contribution to a low capex-to-overnight construction cost ratio. The 80% is calculated based on the total cost to build the plant, including the early development costs and the debt interest accrued during construction.

- Equity Early Development Rate of Return: 20%
- Equity Construction Rate of Return: 14%
- Debt Construction Finance Interest Rate: 5%

This analysis does not further break down categories of equity and debt and assign various rates of return or interest rates within those categories.

Conclusion

The costs of nuclear power plant development will escalate rapidly throughout the project development timeline. These costs escalate in a stepped curve, allowing for clear decision

[25] World Nuclear Association. "Economics of Nuclear Power". September 29, 2023. https://world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power#CapitalCosts
[26] Lazard. June 2025. Levelized Cost of Energy+. lazards-lcoeplus-june-2025.pdf

points and project restructuring between phases. This can allow owners and investors to join and exit the project based on their areas of expertise or risk appetite.

One key reason to develop this timeline was to quantify the cost of project financing and establish the capital expenses (CapEx), of the project. CapEx is the sum of overnight capital costs and construction financing costs. The CapEx is an important input into the Levelized Cost of Energy (LCOE) analysis, and also represents the total value of the project at COD. The financial analysis described above results in CapEx being 30.8% higher than the Overnight Capital Costs (OCC). Put another way, owner's returns and construction debt interest costs account for 23.5% of the project's total CapEx.