Advanced Nuclear Power Program

Overnight Capital Cost of the Next AP1000

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Table of Contents

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Executive Summary

Nuclear energy has been reinvigorated as a scalable and reliable pathway to produce carbon-free energy by governments and companies that are pursuing deep decarbonization targets. One such technology developed during the last four decades and under deployment/deployed in the U.S. and China, respectively, is the 1150 MW-electric AP1000 Generation III+ nuclear power plant. AP1000 is now a proven technology that is able to produce almost 10,000 GWh of clean energy per year with a plant lifetime that can be readily extended to 80 years and beyond. Before the fracking boom that led to low price of natural gas, AP1000 was primed to be a major nuclear technology with over 20 units under operation by this decade. However, the availability of cheaper alternative energy sources along with First-Of-A-Kind (FOAK) cost experience and schedule delays with AP1000, particularly in the U.S., have led to only 2 plants being currently under construction at the Vogtle site in the U.S. For the energy sector, the Vogtle project has been a clear example of why nuclear energy is not competitive with alternative energy sources with a total price tag of $28 billion dollars as of July 2021 and rising for the two 1150 MWe plants (~$14+ billion for each reactor, inclusive of Owner costs and financing).

This report summarizes an independent assessment of what the next AP1000 series should cost in the context of the experience realized at the Vogtle site. The "should cost" decouples the impact of cost by competency of the reactor vendor, supply chain logic and construction execution from the design architecture. It is also essential to ensure comparison of like costs (FOAK or Nth-Of-A-Kind (NOAK)) when evaluating future technology selections, in recognition that most publicized costs are NOAK exclusive of owner's and financing costs. The Vogtle Unit 3&4 projects have experienced several one-time delays including redesign and reworks from the first application of 10CFR52 design certification process and insufficient engineering before start of the construction. Contrary, to perhaps the consensus verdict among U.S. utilities, the AP1000 NOAK estimated overnight capital cost, which still requires large capital investment to realize, continues to make AP1000 an attractive option for nuclear energy development globally. The realized and current projected cost for Vogtle is found to be consistent with the post-TMI (Three Mile Island Accident in 1979) cost for large nuclear power plant construction in the U.S. (see Table I).

A recent 2019 MIT study, based on assuming similar construction productivity as the pre-1980s in the U.S. and by considering the cost for construction of 4 units of AP1000 in China (~$2,000/kW for the overnight capital cost) and recent FOAK international nuclear construction experience of plants with existing demonstrations, **estimated the "should cost" of the next AP1000 overnight capital cost in U.S. to be \$4,300/kW and \$2,900/kW for the following 10th unit (online by ~2045), deployed in series, based on 2018 dollars (see Table I).** The noted "should costs" could be further escalated due to loss of on-site construction productivity in the U.S. (in all sectors) since the 1980s by as much as 1.33x. Additionally, considering the unique Post-COVID inflation and rise in material index cost, the cost could be further escalated by as much as 1.2x. This means the next AP1000 could cost as high as \$6,800/kW and \$4,500/kW for the following installed 10th unit, based on 2022 dollars (see Table I). While the levelized cost of electricity (LCOE) at these capital price points will not be immediately competitive in most U.S. markets (i.e., greater than \$60/MWhre), long term decarbonization goals combined with the long lifetime of the plant (i.e., LCOE of less than \$30/MWhre for 40-60 years) should motivate revisiting the AP1000 economic feasibility if decarbonization targets are taken seriously.

Globally, the lower labor rates, owner's costs and indirect costs relative to the U.S., can make AP1000 an affordable technology for displacing existing carbon emitting power plants. The AP1000 features a compact nuclear island per kWe produced (i.e., lower amount of concrete and steel per kWe) with fewer number of nuclear safety grade components relative to other GENIII/III+ reactors including the EPR and APR1400. This is due to AP1000 reliance on *passive safety*. AP1000's robust station black out scenario response without any need for offsite support already provides effective protection against Fukushima-type events. Since among the large water reactors, the O&M and fuel costs are similar, the capital cost remains the key differentiator among the plant architectures, which makes the compact footprint of the AP1000 an attractive technology choice.

Meanwhile Small Modular Reactors (SMRs) overnight costs per kWe are estimated to be 1.4 - 1.75x the cost of the next AP1000 plant because of the lack of economy of scale. While most SMRs only deliver a fraction of MWh energy of AP1000 (4-10x less) which can lead to very high levelized O&M costs, they are characterized by significantly lower total onsite and offsite labor-hours which will reduce the risk to cost overruns. This can potentially allow SMRs of less than 300 MWe to avoid post-TMI FOAK cost escalations realized by the western large reactors. As such, SMRs are an attractive option for certain markets where small additional capacity of carbon free energy is needed. However, if multiple SMRs are housed in a single reactor building (e.g., NuScale), then no measurable reduction in overall onsite labor input compared to AP1000 is expected and the capital cost will be higher than a large reactor due to the large volume of concrete and steel per MWe produced. In addition, for government led investments, where access to low interest rate debt is accessible, the merits of pursuing SMRs vs. large reactors are reduced. Besides, if governments want to lead large decarbonization efforts, it makes sense to invest in a fleet (>8 orders) of large LWRs (e.g., AP1000) for the most economic and impactful option.

In summary, the current AP1000 cost overrun and schedule delays on the Vogtle project are well predicted by U.S. empirical cost data (see Table I). Similar empirical cost data imply that the overnight capital cost of $2,900/kW for the next 10th unit in the U.S. is achievable. For international deployment, some one-time FOAK issues will be reintroduced while the lower labor and management costs and typically higher productivity compared to U.S. will drive down the predicted cost estimations. **AP1000 is an attractive technology for large scale decarbonization, since it features a compact design in terms of amount of concrete and steel used per MWe generated compared to leading large LWRs and SMRs (i.e., lowest direct "should cost") while still generating over 1000 MWe of carbon free electricity (i.e., low O&M cost).**

Table I. Historic PWR (1200 MWe) costs pre-/post-TMI compared to AP1000 (2018 dollars); Vogtle Unit 3&4 projected costs*; independent estimated direct cost with post-TMI indirect cost escalation (2018 dollars); independent "should cost" estimation for next and the following 10th unit cost for U.S. (2018 dollars); independent high-end (or bounding) cost estimation accounting for Post-COVID escalation and uncertainty in construction productivity (2022 dollars).

Parameters	**EPC Overnight ($/kWe)**	**Construction Time (Months)****	**Total Cost (B$)*****
Historic PWR Pre-TMI	4,700	~100	11
Historic PWR Post-TMI	9,512	~150	21
Vogtle Unit 3&4 Project (2021*)	7,956	~120	14 for 1 unit 28 for 2 unit
Estimated Post-TMI Vogtle 3&4	9,200	~130	32 for 2 unit
Next AP1000 (Should Cost)	4,300#	~60	--
10th unit AP1000 (Should Cost)	2,900#	~50	--
Next AP1000 (High-end Estimate)	6,800	~100	--
10th unit AP1000 (High-end Estimate)	4,500	~60	--

*Numbers obtained by dividing Georgia Power Company (GPC) projected cost in July 2021 by ~0.47 to approximate total project cost since GPC only owns ~47% of the project. As of Feb 2022, the estimated cost has risen to ~$32 Billon which is close to the independent prediction in row 5.
** Estimates have been rounded to the nearest 5-month increment.
*** Numbers include financing cost and Owner's costs based on Vogtle Unit 3&4. The total cost of future AP1000 projects will depend on owner/operator owner's cost and financing scheme.
# Based on 2019 MIT peer-reviewed study: https://doi.org/10.1016/j.rser.2021.111880

I. Background

The 1000 MWe+ class of Generation III/III+ nuclear power plants include the AP1000 (1150 MWe), EPR (1650 MWe), APR-1400 (1450 MWe), VVER-1200 (1200 MWe) and ABWR (1350 MWe). According to the NEA OECD report on project cost of electricity (Table 8.2)[1], on average GEN III/III+ reactors except for the ABWR realized over 2x in schedule delay and cost overrun. The ongoing AP1000 Vogtle project in the U.S. has faced similar severe delays and cost overruns since its start of construction in 2012. These setbacks have decimated U.S. energy utilities' interest in large nuclear power plant construction projects. The general energy sector also utilizes the experience at Vogtle as an indicator of nuclear energy's high cost and infeasibility of the role it can play in future energy markets. However, several unique project parameters have led to the inflation of the Vogtle total project cost, including high interest rates, lack of detailed design prior to start of construction, construction management turnover and first-of-a-kind (FOAK) issues. In the U.S., AP1000 is the first Generation III+ nuclear technology and the first nuclear power plant licensed under a new Code-of-Federal Regulation (i.e., 10CFR50.52). This lack of prior experience led to the inefficiencies in the interactions between Engineering, Procurement and Construction (EPC) entities and the regulators and quality assurance requirements that resulted in significant delays. These issues resemble the nuclear power plants experience post-TMI, where new regulatory standards and interactions led to abandonment and severe delays in the majority of plants under construction.

Nevertheless, almost 10 years after the start of construction in the U.S., the AP1000 is now a proven technology with 4 operating plants in China. AP1000 continues to feature a high degree of safety and simplicity in the number of safety related structures, systems and components (SCCs) and a compact nuclear island footprint relative to energy output when compared to other Light Water Reactors (LWRs), both giga-watt and SMRs (see Fig. 4). The FOAK Chinese design civil work proved to be constructible as the civil work in Haiyang Unit 2 was finished in less than 4 years. The main source of delays in Chinese AP1000 designs were the reactor coolant pumps that

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[1] IEA, NEA, Projected Cost of Generating Electricity, 2020 [Link]

were FOAK technologies and were also subjected to complex export control scope. As such, the next AP1000 plant has potential to provide a viable product in the U.S. and oversees if its original NOAK capital cost and construction schedule projections by Westinghouse can be realized. The positive experience with the ABWRs in Japan (e.g., less than 50-month construction period) imply that the combination of experienced EPC contractor and modular construction approach and replication can lead to a success story for the large reactors. To assess the question of what a AP1000 NOAK should cost, first an overview of its cost based on an independent study performed recently at MIT is given in context of both capital cost ($/kW) and Levelized Cost of Electricity (LCOE). Then, the cost overrun at the Vogtle project is explained based on the data provided by the Georgia Power Company (GPC) to the Georgia Public Commission. Finally, a brief comparison of the AP1000 technology relative to other near-term nuclear technologies including large reactors and Small Modular Reactors (SMRs) is also included.

II. AP1000: Capital Cost and Levelized Cost of Electricity

Nuclear power plant cost predictions and projections are currently subjected to high uncertainty as supported by existing literature. For instance, Lazard projects the capital cost of a nuclear power plant at $6,900 – $12,200/kW[2] while OECD Nuclear Energy Agency projects the capital cost between $2,157-$6,920/kW.[1] Back in 2004, Westinghouse estimated an AP1000 cost of $1,000/kW.[3] Similar discrepancy is found for the noted Levelized Cost of Electricity (LCOE) where the assumptions behind the levelization of the cost are not consistent. This section discusses AP1000 cost in the following order: Overnight capital cost (or EPC cost), Owner's cost, financing cost, O&M, Fuel and the resulting LCOE.

II.A. EPC Overnight Capital Cost

In order to arrive at an empirically supported and independent cost estimation methodology on the relative economic merit of different nuclear power plant architectures, a Nuclear Cost Estimation Tool (NCET[4]) has been recently developed at MIT.[5] Over 8[6] plant architectures including AP1000 were analyzed based on cost of over 200 SSCs and compared to published projected and realized costs. The median FOAK overnight cost (excluding owner's cost) of a plant architecture that resembled an AP1000 was estimated at ~$4,300/kW (2018 USD) for U.S. which agrees well with the original reported EPC costs for Vogtle plus the construction management projected cost as of 2021 ($4,500/kW). The NCET also predicted an overnight cost of ~$2,000/kW for China (different labor cost) which agrees well with reported cost for Sanmen and Haiyang plants.[1] These FOAK cost estimations are scaled based on cost data for the "Median experience" LWR plants that were constructed in the past and are tabulated in the Economic Energy Data Base (EEDB) of the late 1980s.[7] The overnight cost is made up of direct cost plus indirect cost as listed in Table II.

[2] Lazard, Lazard's Levelized Cost of Energy Analysis – Version 13.0, Nov. 2019 [Link]
[3] Allen, J.B., and Matzie, R.A. Fulfilling the nuclear promise - the AP1000 nuclear plant. Japan: N. p., 2004 [Link]
[4] NCET will be open sourced on Github in April 2022 (contact kshirvan@mit.edu for more info).
[5] Stewart R., Shirvan K., Capital Cost Estimation for Advanced Nuclear Power Plants, Renewable and Sustainable Energy Reviews, Volume 155, March 2022 https://doi.org/10.1016/j.rser.2021.111880
[6] GENIII/III+: AP1000, ABWR, EPR*, APR-1400, PWR12 (*has not been publicly published yet.)
[7] U.S. DOE Phase IX update (1987) report for the Energy economic data Base program U.S. Department of Energy (1988).

Table II. Selected EEDB Code of Accounts (top contributors are shown)

Direct Cost	Nuclear Steam Supply System
Direct Cost	Air Water and Service System
Direct Cost	Reactor Containment Building
Direct Cost	Turbine Generator
Indirect Cost	Engineering & Home Office Services
Indirect Cost	Construction Services
Indirect Cost	Field Supervision & Field Office Service
Indirect Cost	Payroll Insurance & Taxes

The EEDB database assumes that 51% of the total overnight cost is indirect cost for the median experience PWR12, which is a generic 1200 MWe PWR based on pre-TMI historic cost numbers. This is the percentage used for indirect cost for the NCET FOAK estimations.[5] This assumption is justified because the U.S. plants were never standardized and were typically not replicated on the same site for more than 2 units at the time. This resulted in significant FOAK issues to be realized from site to site, even though the reactor technology and architecture was already demonstrated. However, the 51% factor inherently assumes the vendor and owner/operator of the plant are able to leverage established regulatory framework, the plant design is already completed, and sufficient labor force can be recruited. These conditions were not met for the ongoing Vogtle Unit 3&4 project as well as plants built after the TMI accident in 1979. As noted in the MIT Future of Nuclear Study,[8] the EEDB recommends a 77% indirect cost for reactors built post-TMI accident. Another recent study by MIT, similarly noted that the indirect cost portion escalated to 72% based on Post-TMI cost data from EEDB and other sources.[9] The TMI accident resulted in substantial additional delays due to regulatory inefficiencies (the realized indirect cost of 72-77% is revisited in Section III). On the other end of the indirect cost, the Nuclear Energy Agency (NEA) recommends assuming 30% indirect cost[1] based on international nuclear construction experience. The indirect cost for other baseload energy sources such as combined natural gas plants can be as

[8]Buongiorno J.B., et al., Future of Nuclear Energy in a Carbon Constrained World, 2018. [Link]
[9] Eash-Gates et al., Joule 4, 2348–2373 November 18, 2020. [Link]

low as 20%[10]. The assumptions on indirect cost are highly dependent on the percentage of design completion, experience of the construction management, EPC contractors, construction schedule and the regulatory interface for the particular site and country (and their respective management, engineering and labor costs). Therefore, as more plants are built by the EPC vendor, the relative indirect cost should decrease.

In literature and marketing materials, nuclear vendors typically report NOAK cost estimates as FOAK costs are not representative of the true cost potential of their technologies. Regardless of technology, from the first nuclear power plants to the first coal to natural gas to wind turbines, the FOAK costs are substantially higher. In the nuclear world, NOAK cost for standardized technologies has been achieved by few countries including France, Japan and South Korea (ROK). Building more than 10 reactors consecutively allows achieving low costs for the direct portion of the capital cost (minimizes rework) but particularly reduces indirect cost (sharing of engineering and management experience among units). This overall cost reduction (on the order of ~25%) is illustrated in Fig. 1 by averaging the historic French (P4 reactor series) and more recent ROK experience (OPR-1000 reactor series). The NCET assumes different learning rates for onsite construction and factory-based manufacturing and applies them to the relevant ~200 SSCs for each plant architectures.[5] The learning assumes that reactors are constructed consecutively without major gaps in time to ensure transfer of onsite and offsite labor/factory experience. The result of the assumed learning rates reduces the indirect cost to ~40% of the total cost for the 10th-of-a-kind. This is consistent with historic data as shown in Fig. 1. As alluded to earlier, NCET also assumes that learning is not really transferred from one country to another as median FOAK costs estimates will be experienced unless the mentioned one-time delays due to regulatory changes or labor shortages are experienced. As such, the AP1000 next 10th unit "should cost" was predicted to be $2,900/kW (2018 USD).[5]

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[10]Black and Veatch, Final 2013 Power Station Characterization Study, 2013 [Link]

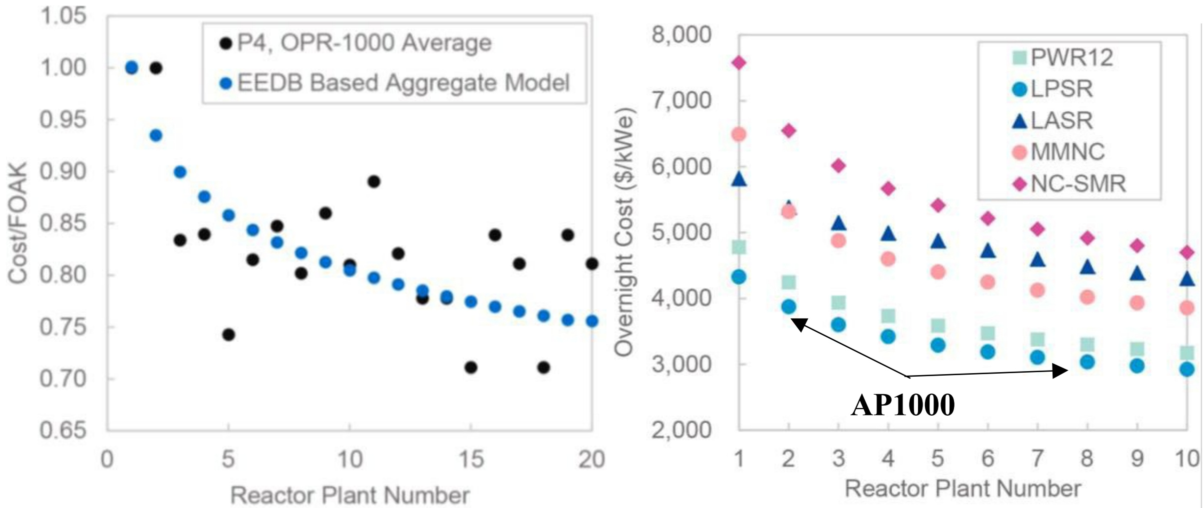

Fig. 1. (Left) Average of the P4 and OPR-1000 costs and the EEDB based learning model aggregating factory, labor, and material cost learning rates and thresholds (Right) AP1000 (noted as LPSR) cost reduction compared to other reactors assessed in [5]

The above referenced cost estimation published by MIT NCET tool[5] made two key assumptions that is critical for forecasting the cost of the next AP1000 that could result in further escalation:

(1) the study utilized 2018 U.S. labor Bureau of labor statistics which also reports official numbers as late as May 2020. Since 2018, with COVID-19 impact on world economy, there has been significant inflation (~12% compared to 2022) and rise in material supply index (20-80%), particularly for steel (~30%). If we apply such escalations to previously noted numbers, separately escalating labor and materials, the noted overnight capital cost numbers should be escalated by ~20% ($4,300/kW to $5,100/kW for next AP1000 and $2,900 to $3,400/kW for the next 10th unit).

(2) The study assumed construction labor productivity similar to early 1980s. It is well-known that U.S. on-site construction labor productivity (for nuclear and non-nuclear projects) has decreased by 2X.[8] This will be discussed as one of the potential major reasons behind Vogtle 3&4 construction delays in section III. Utilizing the same methodology for cost escalation of 2X in loss of labor productivity as section III, the predicted cost will increase by ~33% ($5,100/kW to $6,800/kW for next AP1000 and $3,400 to $4,500/kW for the next 10th unit).

It should be noted that the noted escalations are also applicable to all designs analyzed previously.

II.B. Cost Elements beyond EPC Overnight

II.B.1 Owner's Cost

The owner's cost (e.g., Project development, management, financing, legal, interconnection, etc.) is typically not included in the quoted overnight capital cost by nuclear vendors. B&V estimates the owner's cost of different energy sources in the U.S. and assumes nuclear is similar to a coal power plant at 40-45% of EPC cost.[10] By assuming 45%, this gives a predicted FOAK and NOAK owners cost of $1,900/kW (0.45x4,300) and $1,300/kW (0.45x2,900) for the AP1000 based on the NCET predictions, respectively. The GPC reported projected $1,448M for owner's cost for the Vogtle project.[11] Approximating 47% ownership for GPC, the owner's cost of $1,448M/0.47/ (2x1150,000 kWe) = $1,344/kW is obtained. This is in the same range as the figures derived from B&V simplified methodology (this is further revisited in Section III). Therefore, the next AP1000 and 10th unit overnight capital cost inclusive of owner's cost for the AP1000 are $6,200/kW (4,300+1,900) and $4,200/kW (2,900+1,300), respectively in 2018 USD. It is noted that the Owner's cost should naturally decrease as more units are constructed on the same site.

II.B.2 Financing Cost

The last element of total capital project cost is financing cost. We can estimate the financing cost of a nuclear plant based on the discount rate, x with a simple multiplier factor: 1+N x/2, where N is number of construction years. Typically, a discount rate of 8% is assumed though it can vary widely depending on the market. A large reactor will typically take 72-96 month from first concrete pour to fuel-load (assuming average FOAK-type project). Given the noted 4-year civil work construction experience in the AP1000 in China, it is conceivable that the 10th unit of AP1000 could be deployed in 60-month. Independent schedule modeling work showed that the modular construction approach adopted in AP1000 should allow it to be constructed at the same rate as the ABWR in Japan (<40 month), or twice as fast as a large stick build reactor[12]. At 8% discount factor and 96-month construction period, the total project cost would increase by 1.3x. Similarly, at 8% discount factor and 50-month construction period, the total project cost would increase by 1.2x.

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[11] Georgia Power Company's Twenty-fourth Semi-annual Construction Monitoring Report for Plant Vogtle Units 3 and 4; Docket No. 29849

[12] Stewart, W. R., et al. (2022, January 26). Construction duration estimation for advanced nuclear power plants. [Link]

This gives the next and 10th AP1000 total project cost of \$9.34 billion and \$6.43 billion, respectively in 2018 USD, based on the independent NCET estimate of a single unit AP1000. If a 50-month construction schedule for the 10th unit is achievable, the total project cost at 8% discount rate can be reduced to \$5.74 billion in 2018 USD.

The above simplified financing equation assumes a 50/50 equity-to-debt ratio. Financing also will depend on the revenue stream and other factors that is not captured by the very simplified model. Overall, the financing cost structures incentivizes governments to invest in large reactors and private utilities to take on small reactors to reduce risk and lower the project cost profile. For example, government provided discount rate of 4% can reduce the estimated next AP1000 cost by more than a billion dollars.

It is worth noting that construction duration also impacts indirect costs. A reduction in construction duration implies less rework and less utilization of additional materials at site. It also means less costs for upkeep of temporary construction services and home offices. As sensitivity of construction duration on the next AP1000 with respect to indirect cost was performed by Stewart et al., 2022[12] and shown in Fig. 2. At greater than 60-month construction duration, the indirect cost starts to grow more rapidly.

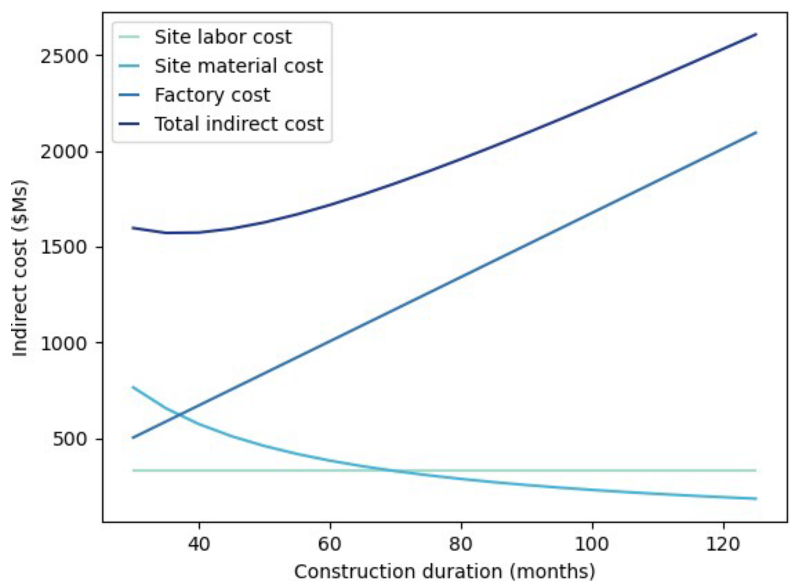

Fig. 2. Next AP1000 indirect costs for fixed direct costs and varying construction durations (Figure from 12).

II.B.3 O&M Costs

In this subsection, the O&M cost data for current U.S. LWR fleet and projected O&M cost data for AP1000 are provided. Table III lists the breakdown of O&M cost for an average existing 1000 MWe LWR plant ("GenII") based on data provided by NEI in 2018.[13] An estimate was developed for O&M of an AP1000 plant as there are published data by INPO and Westinghouse that estimates roughly a 200 staff reduction from 600 total staff to 400 staff as listed in Table III. The savings in the support services cost category was estimated to be 30% from the simplification of AP1000 compared to existing reactors.[5] As shown, such simplifications also allow an AP1000 plant to be staffed close to the best multi-unit sites in the U.S., which drives down its estimated O&M cost. It should be noted that O&M cost is a strong function of number of units operating on a site. U.S. engineering consulting firms estimated that an additional unit will require 60% of the first unit staff.[14] This gives a 2-unit and 4-unit AP1000 an O&M cost of $11 and $9/MWhre, respectively.

Table III. Staff and cost data for O&M for the current fleet per year.

Categories	GENII Staff	GENII Cost ($M)	AP1000 Staff	AP1000 Cost ($M)
Engineering	68	12.4	59	10.8
Loss Prevention	132	21.8	72	11.9
Materials & Services	18	3.2	18	3.2
Fuel Management	7	1.0	7	1.0
Operations	136	27.4	86	17.3
Training	31	4.2	31	4.2
Work Management	158	43.8	112	31.1
Support Services Staff*	49	9.0	19	3.5
Support Services	--	43.0	--	30.1
Fixed Fees**	--	15.0	--	15.0
Total	599	180.9	404	128.0
Levelized ($/MWhre)	--	22.9	--	14.1

* Estimated based on average staff salary from other categories.
** Covering NRC/NEI/INPO/Outage Fees[15]

[13]Nuclear Energy Institute, Nuclear Costs in Context, 2018 [Link]
[14] Study of construction technologies and schedules, O&M staffing and cost, decommissioning costs and funding requirements for advanced reactor designs. Report prepared by Dominion Energy, Inc., Bechtel Power Corp., TLG, Inc. and MPR Associates for the US Department of Energy under Cooperative Agreement DE- FC07-03ID14492. Washington, D.C.: 2004.
[15] Assessment of High Temperature Gas-Cooled Reactor (HTGR) Capital and Operating Costs, Technical Evaluation Study, Project No. 23843, TEV-1196, 2012.

II.B.4 Fuel Costs

Similar to other GEN III/III+ plants, the AP1000 adopts the traditional PWR 17x17 fuel assembly type with some added complexity (e.g., gray rods, varying enrichments within a bundle) that are not expected to increase its cost since it targets similar specific power (kW/kgU) and discharge burnup as existing fleet. As such, assuming the current fleet fuel cost estimate by NEI of \$6.15/MWhre[13] is well justified.

II.C. Levelized Cost of Electricity

There are several ways that one can estimate LCOE. Here, a methodology as recommended by NREL is adopted (from 16):

$$\mathrm{LCOE} = \frac{\text{Overnight Capital Cost} * \mathrm{CRF} * (1 - \mathrm{T} * \mathrm{Dpv})}{8760 * \text{Capacity Factor} * (1 - \mathrm{T})} + O\&M + Fuel\ [\$/MWhre]$$

Where CRF is capital recovery factor, turning capital cost into annual values.

$$CRF = \frac{\mathrm{D} * (1 + \mathrm{D})^{N}}{(1 + \mathrm{D})^{N} - 1}$$

The following values are assumed to calculate LCOE based on some of the noted parameters in the previous sections as listed in Table IV.

Table IV. Assumed values for next AP1000 and the following 10th Unit AP1000 (OCC: Overnight Capital Cost plus Owner's cost)

Parameter	Next AP1000	10th Unit AP1000
D – Discount rate	8%	8%
N- Lifetime of Investment/Loan (Yr)	20 and 80	20 and 80
Dpv – Present value of depreciation	0.595	0.595
T – Tax Rate	40%	40%
Capacity Factor	0.93	0.94
OCC ("Should Cost" in 2018 USD ($/kWe)	6,235	4,300
OCC in 2020 USD ($/kWe)*	7,270	4,860
OCC in 2020 USD with loss of labor productivity escalation ($/kWe)*	8,960	5,990
O&M Cost ($/MWhre)	14	9
Fuel Cost ($/MWhre)	6.15	6.15

* Accounts for unique Post-COVID escalation and potential bounding low labor productivity, respectively.

[16]Alexandra Bratanova, LCOE models: A comparison of the theoretical frameworks and key assumptions, [Link]

If inputs from the latest Lazard report[2] are fed to the above equations, then less than 1% difference on projected LCOE for a nuclear plant is obtained ($118-193/MWhre) compared to Lazard estimates. However, the Lazard numbers are highly inflated based on the Vogtle AP1000 project (see Section III) and higher than nuclear industry realized fuel and O&M costs.

If the noted AP1000 "should cost" and high-end cost for the next AP1000 and 10th unit noted in Table IV (.i.e. probably and bounding OCC values are utilized), then LCOE of $119-162 and $81-109/MWhre for 20-year loan (N=20) and LCOE of $98-132 and $67-89/MWhre for 80-year lifetime (N=80) is obtained, respectively. These LCOE's are for the U.S. based on its wages, management and operating costs. For the Sanmen plant, which was estimated to be third of a cost of the U.S. plant, the FOAK LCOE can reach <$70/MWhre given the low wages in China.

In general, after 20-40 years, depending on the investment and cost recovery assumptions with the capital cost, the LCOE of nuclear power plants will significantly be reduced. In fact, the additional capital cost of keeping the existing fleet through life extensions and refurbishments is only between $5-$10/MWhre.[13] For an AP1000 that has design features allowing it to be readily licensed to 80 years, it can provide electricity at $20-$40/MWhre cost (depending on number of units and refurbishment investment rates) for 40-60 years after the capital cost has been paid off. This is another attractive quality of large, water-cooled reactors, particularly, for governments who can afford long term investments and provide low interest rates on the raised capital debt.

III. What happened at Vogtle

In summary of the previous section, MIT independent bottom-up cost estimation (NCET) for AP1000 agrees well with prior Westinghouse and US Utility reported numbers ~$4,300/kW in 2018 dollars for U.S. exclusive of owner's cost or project financing. Using 2018 dollars for comparison in this section is justified since most of Vogtle construction and equipment procurement took place pre-COVID era and did not realize the substantial increase in material (particularly steel) index price. Accounting for cost of labor difference, this estimate agrees well with the realized cost of the Sanmen AP1000 project in China.[5] Current realized and projected cost estimation for the Vogtle plants are about $28 billion total for both reactors (includes the $6 billion refund from Toshiba) as listed in Table V.

Table V. AP1000 Vogtle plant cost estimation for the Georgia power portion (46.7%) [Figure from Reference 11].

Parameter (Millions of $)	GPC Report	Total Project	Cost per kWe
Original EPC	3,198	6,833	2,971
Iterim Payments and Liens	411	878	382
Site Construction Management	4,948	10,573	4,597
Owners Cost	1,448	3,094	1,345
Total Overnight Cost (Without owners cost)	8,557	18,284	7,950
Total Overnight Cost (With owners cost)	10,005	21,378	9,295
Toshiba Repayment and absorbed costs	2,705	5,780	2,513
Total Project Financing	3,024	6,462	2,809
Total Capital Cost and Financing	13,029	27,840	12,104

This means the total capital cost of $12,500/kW similar to the "high-end" projected overnight cost of latest Lazard report.[2] *However, this number includes both owner's cost and financing cost. As such it is incorrect to be quoted as an overnight cost for an LCOE calculation.* Particularly for the latter, the financing of the Vogtle project has been complex. For instance, Georgia Power that publishes detailed cost report only holds approximately ~47% share of the project. There are several loan guarantees and recovery of cost by Southern company rate payers. There is also debt repay from Toshiba (former Westinghouse majority holder) due to the announced bankruptcy and exit from the project. Table V lists values taken from the full GPC report on July 2021, and then converts them to more usable units and scales them based on GPC share of the project for a 2-unit 1150 MWe plants.[11]

Removing project financing from the picture, GPC's share of the total construction and capital cost including Owner's cost is $10 billion. This means the total capital cost for the two AP1000 are $10 billion/0.47 = $21.39 billion or $9,300/kW (see Table V row 7) for the overnight cost plus the owner's cost given a 120-month construction period. This figure is 1.5x the NCET estimate for what a next AP1000 should cost based on 2018 USD and early pre-1980s construction productivity. The construction time has gone twice as long as the initial assumed AP1000 schedule, as such the indirect cost has almost doubled, consistent with the trend shown in Fig. 2. Revising the NCET 2018 USD cost estimate (see Table IV row 7) with 2x indirect cost results into a $9,400/kW overnight capital cost estimate (includes owner's cost) that is very close to the realized estimate by GPC thus far in the project. This means that the share of indirect cost was raised from 51% to 68%. If the owner's cost of the next AP1000 is used for the Vogtle estimation ($1,900/kWe mentioned in Section II.B.1), then indirect cost of 72% results in matching the GPC estimate. As noted earlier, the historic post-TMI large U.S. nuclear reactor indirect cost should be 72-77% of the total cost. Therefore, the cost of AP1000s at the Vogtle site are roughly in-line with the realized cost of LWRs post-TMI where no standardization in design or licensing framework was present (attributes of FOAK AP1000 experience). Below details the calculations discussed in this paragraph:

NCET 2018 USD FOAK AP1000 OCC Estimate (without owner's cost): $4,300/kW[5]
Direct Cost (49% of OCC): $4,300/kW x 0.49 = $2,107/kW
Indirect Cost (51% of OCC): $4,300/kW x 0.51 = $2,193/kW
2x Escalation of Indirect Cost at Vogtle due to schedule overrun: $2,193/kW x 2 = $4,386/kW
New OCC Estimate based on escalated indirect cost: $2,107/kW + $4,386/kW =$6,493/kW
New percentage of Indirect cost as part of OCC: $4,386/kW/$6,493/kW x 100= 67.5%
New Owner's Cost based on B&V methodology: $6,493/kW x 0.45 = $2,922/kW
New OCC plus Owner's Cost: $6,493/kW + $2,922/kW = **$9,414/kW**

There are several potential reasons for the escalation of indirect cost in the nuclear industry. Productivity of onsite labor has decreased by ~2x on construction-sites since the 1980s (of when most studies base their costs from).[8] Regulatory inefficiencies is another reason which drives the indirect cost on post-TMI plant construction. 10CFR50.52 was intended to lower the risk of achieving an operating license but has significantly complicated the regulatory interface at Vogtle.

The described approach utilized NCET independent estimation and B&V owners cost estimation (45% of the overnight cost excluding owner's cost). Another approach is to estimate the realized cost of Vogtle utilizing some of the numbers provided by GPC in order to additionally investigate the key drivers behind the cost escalation. GPC reports the Owners cost total of $1,448M or $1345/kW (See section II.B.1. and Table V row 5). The original EPC contract was $3,198M which translates to $2,971/kW (See Table V row 2). Iterim Payments and Liens ($382/kW from Table V row 3) are assumed to be part of EPC and are added to it: $3,353/kW. As noted in Table V, this EPC cost does not include "Site construction management" that is provided separately by GPC. For NCET, the site construction management cost is part of the indirect cost. It is assumed that "site construction management" is equivalent to "site construction services" EEDB code of accounts under indirect cost. For EEDB, this accounts for 65% of the indirect cost[7] (or $1,425/kW in 2018 USD):

NCET 2018 USD FOAK AP1000 OCC Estimate (without owner's cost): $4,300/kW[5]
Indirect Cost (51% of OCC): $4,300/kW x 0.51 = $2,193/kW
Site construction management (65% of Indirect cost) = $2,193/kW x 0.65 = **$1,425/kW**

If this cost and the Owner's cost derived from GPC ($1345/kW) are added to the EPC cost ($3,198/kW) noted in previous paragraph, overnight cost of $6,000/kW or $4,600/kW without Owner's cost is obtained:

GPC's EPC+Owners +NCET's Construction management = 3,198/kW + $1,345/kW + $1,425/kW
= 5,968/kW or $4,623 / kW without GPC Owners

These two costs are close to the next AP1000 estimated cost in 2018 USD based on median cost of pre-TMI estimation provided by completely independent NCET estimations: 6,200/kW with Owner's cost and 4,300 without Owner's cost as noted in Section II.B.1 and Table IV row 7.

However, when comparing these numbers plus owner's cost to the Vogtle project, the difference between projected cost of $9,500/kW and $6,000/kW comes from the difference in estimated "site construction management" cost. The "site construction management" is actually $4,948 Million or $4,948/0.47/ (2 * 1,150,000 kWe): $4,600/kW. This is a 3.2x increase ($4,600/$1,425) over the NCET estimate for the next AP1000. As mentioned, the site construction productivity has gone down by a factor of 2x since the 1980s. Given FOAK design and construction issues, EPC contractor turnover, and regulatory oversight induced delays at the Vogtle site, it is conceivable to assume construction management cost has increased by a factor of 4x (2x on productivity and 2x on new regulatory issues). Therefore, instead of $1,425/kW, it is $5,700/kW (4x escalation). This escalation in construction management cost, which is the major component of indirect cost, results in a new estimated overnight cost of $10,250/kW, which is close to the realized/projected cost of $9,300 in July 2021. This brings the indirect cost portion of total cost to 76%. This number is close to the post-TMI indirect cost portion of 72%-77% realized in the post-TMI nuclear power construction projects. A Vogtle cost of ~$32 billion (including financing) would validate the 1980s realization of post-TMI indirect cost portion for U.S. LWRs.[17] Below details the calculations discussed in this paragraph:

4x escalation of NCET's Site management estimation = 4 x $1,425/kW = $5,700/kW
GPC derived estimation of OCC plus owner's cost: 5,968/kW
New GPC derived estimation plus 4x escalation of site management: 5,968/kW + $5,700/kW - $1,425/kW (since $5,968/kW already includes site management) = **$10,243/kW**
New GPC derived estimation without GPC owner's cost = $10,243/kW- $1,345/kW = $8,898/kW
New derived indirect cost percent = ($8,898/kW - 2,107/kW)/ $8,898/kW x 100 = **76.3%**

However, as realized post-TMI internationally (e.g., Japan, ROK, AP1000s in China), the FOAK estimated indirect cost portion of 67%-77% in this study and 72-77% realized in U.S. post TMI, can be reduced to ~50% for initial units and 40-30% by 10th and 20th units and potentially even reach 20% if significant plant replication and modularization are adopted. Though, these estimated reductions are supported by empirical construction data outside of U.S., it may be inconceivable that the loss of labor productivity since the 1980s in the U.S. will be fully remedied for the next AP1000 offering. Therefore, the Vogtle experience implies that upto a 2x reduction in site management cost could be possible for the next AP1000 while a 4x decrease may be possible in

[17] In fact, as of Feb 2022, the project costs are closer to total of $32 Billion

markets with improved labor productivity. Accounting for also the unique post-COVID inflation and rise in material index, then on the *high-end* the next AP1000 could reach as high as ~\$6,800/kW and the following 10th unit at ~\$4,500/kW (without owner's cost):

NCET 2018 USD FOAK AP1000 OCC Estimate (without owner's cost): \$4,300/kW[5]
Direct Cost (49% of OCC): \$4,300/kW x 0.49 = \$2,107/kW
Indirect Cost (51% of OCC): \$4,300/kW x 0.51 = \$2,193/kW
Site construction management (65% of Indirect cost): \$2,193/kW x 0.65 = \$1,425/kW
New indirect cost escalated by 2x Site management: \$2,193/kW + \$1,425/kW = \$3,618/kW
New 2018 USD FOAK AP1000 OCC Estimate: \$2,107/kW + \$3,618/kW = \$5,725/kW
New indirect cost percentage of total cost: \$3,618/kW/\$5,725/kW = 63%
Post-COVID 1.18% escalation on labor and materials: \$5,725/kW x 1.18 = \$6,755/kW
(note: same calculation was done for 10th unit by replacing \$4,300/kW with \$2,900/kW at the top that gives ~4,500/kW).

IV. AP1000 Compared to Other Large LWRs

NCET has analyzed architectures resembling AP1000, ABWR, EPR and APR1400, of which only the AP1000, APR1400 and ABWR has so far been published in open literature with EPR to be published in 2022. These estimates are based on available literature and subjected to error. In terms of capital cost, AP1000 brings in compact footprint that results in the lowest total volume of concrete per MWe as supported by Fig. 3 and Fig. 4. Fig. 3 includes the mentioned large LWRs except for the APR-1400. NCET independent estimation of total concrete in APR-1400 based on its NRC design certification was 237 m^3/MWe.[5] This was one of the drivers behind NCET NOAK estimation of ~$4,300/kW (2018 USD) for a plant architecture that would resemble an APR1400.[5] This is noticeably higher than the AP1000 NOAK estimation of ~$3,000/kW (2018 USD). The EPR (see Fig. 4) features reactor building and equipment sizes similar to APR-1400 but produces 15% more power. Therefore, it is reasonable to assume it should-cost to fall between an APR-1400 and AP1000. The ABWR is operates at half the pressure as PWRs without reliance on the steam generators. This resulted in a lower equipment cost for the ABWR compared to AP1000. The equipment cost is an important portion of the total cost for a NOAK cost breakdown where civil rework and indirect costs have been reduced through learning by doing (while remaining significant). At the same time, the ABWR architecture features more concrete and steel per MWe produced (see Fig. 3). As such, the cost estimates for ABWR and AP1000 were similar.

On O&M, due to more reliance on active safety systems, APR-1400, EPR and ABWR may not fully be able to benefit from the same staffing reductions as AP1000 as noted in Table 1. This means a greater number of safety electrical equipment and pumps to maintain. Though, the higher electric power output of these plants, particularly for an EPR will likely offset the higher O&M scope. There is no expectation that fuel cost will be noticeably different between these designs. As such in summary, the capital cost remains the key differentiator among these plant architectures, with AP1000 featuring economic competitive design features.

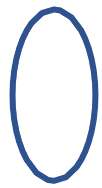

Fig. 3. Estimate of Concrete volume (m^3) and metal (Metric-ton) per MWe for different power plants [Figure taken from 8].

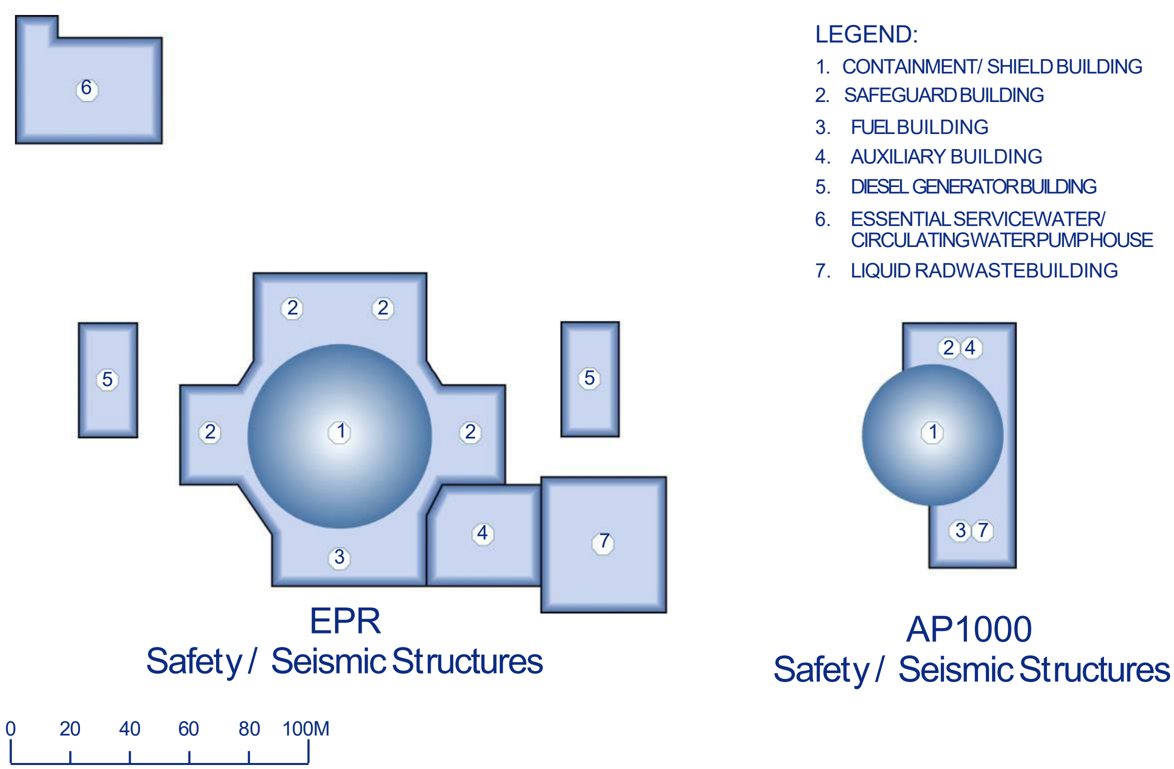

Fig.4. EPR vs. AP1000 safety seismic structures. AP1000 features most compact safety structure footprint and amount of concrete/steel input per MWe compared to EPR, APR1400 and ABWR.[8]

V. AP1000 vs. SMRs

In general, ideally 4-8 units of a nuclear power plant should be built at a single site to leverage learning and sharing of construction experience among the units. This is an obvious advantage for Small Modular Reactors (SMRs) since their total capital cost investment is small. For instance, an AP1000 plant that would cost $8 billion dollars on average each, would require $64 billion investment for a total of 8 units which is very large for the private energy sector to undertake. At the same time, it will take many SMRs to match an AP1000's output. For instance, 32 BWRX300s and 54 SMR-160s would be required. Given the higher learning rates for SMRs, the cost of these plants needs to be within <1.25x of a large plant in order to be able to match the overnight cost. An independent estimate of 3 leading SMRs in the US leads 1.4 -1.75x the cost of an AP1000, mainly because of lack of economy of scale.[5] SMRs can re-gain some of this cost increase through more frequent learning opportunities (.i.e. 2 unit AP1000 can equal to >10-unit SMR which allows the SMR to approach its NOAK cost faster). At the same time, if 4-8x AP1000s are deployed in series then the NOAK can also be rapidly reached, since more than 10 units, the benefits from learning are small, even when accounting for factory learning for the near term SMR architectures. As shown in Fig. 5, the AP1000 or historic PWR-type learning (shown as LPSR and PWR12, respectively), are more cost-effective options compared to LASR (APR1400-type), MMNC (NuScale-type) and NC-SMR (SMR-160-type).

Fig. 5 does not account for financing cost difference between large plants and small plants. An SMR features 36-48 month construction schedule (from first concrete pour to fuel load) while a larger reactor can be 72-96 month (assuming an average FOAK-type projects). At 8% discount factor, the total project cost per kW of SMR relative to a large plant will decrease from 1.4x to 1.2x per kW cost if it can be deployed in 36-month (the low end) vs. the large reactor deploying at 96 month. Only at 12% discount rate and 11 years of construction is when an SMR at best is able to match a large reactor. The above equation assumes a 50/50 equity to debt ratio. For an SMR with lower capital investment, an 20/80 rate may be possible which can get to 1.1x times the per kw cost of a large LWR at 8% discount rate. The lower the discount rate the worse per kW SMR will compare to a large plant. This further incentivizes large governments to invest in large plants while private small utilities invest in SMRs as they do not have access to low discount rates.

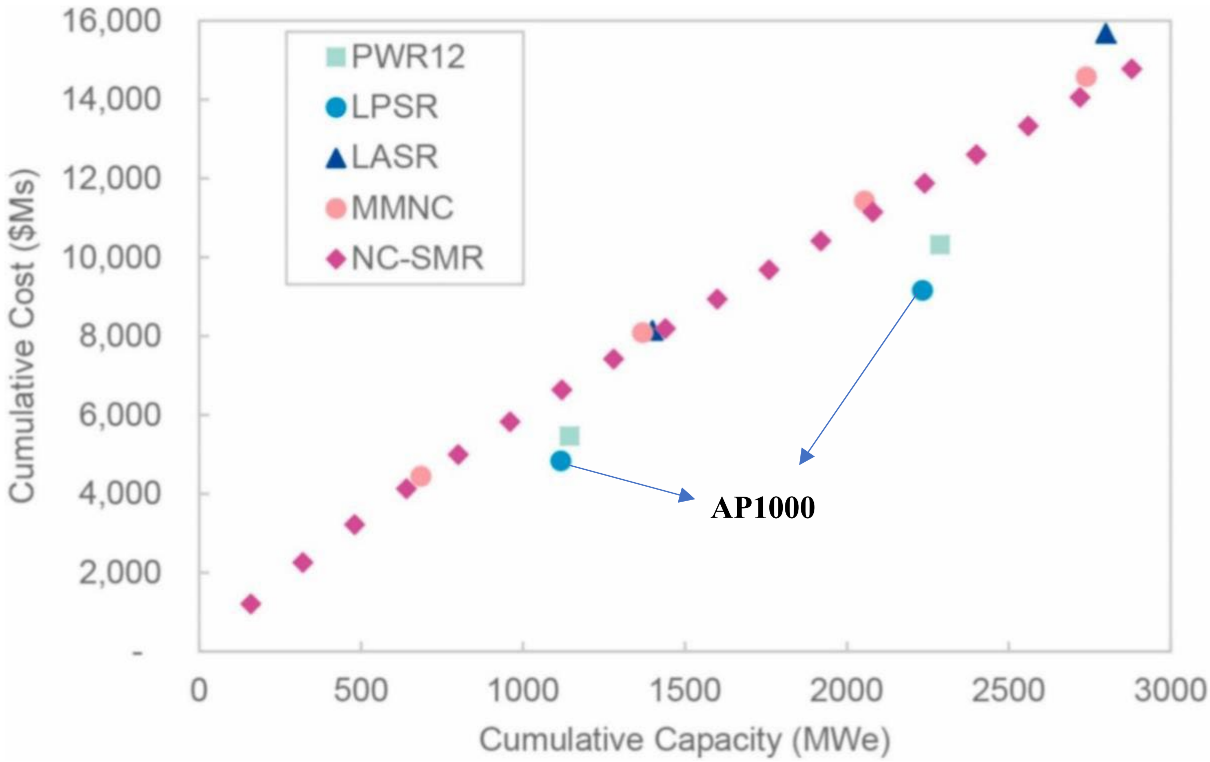

Fig. 5. Cumulative costs (2018 USD) for consecutive deployments of each reactor type: PWR-12, LASR and LPSR are large reactors representing historical PWR, APR-1400 and AP1000 respectively; MMNC and NC-SMR are small reactors representing 12-module NuScale and SMR-160 design. Each point is a new plant (Figure from reference 5)

O&M cost is another area were large plants have clear advantages. Interestingly, the NGNP High Temperature Gas Reactor (HTGR) total staff for the single 600 MWth plant was estimated to be on the same order of the AP1000 plant (383) as estimated by INL.[15] The NGNP supplier group estimated staffing of 165 people but did not reveal details behind the assumptions that led to such low estimate. NuScale has estimated for their 12-plant initially 340 total staff and later revised their estimate to 270 staff. Recently, for the UAMPS demonstration project, NuScale reduced the number of reactor modules from 12 to 6 and estimates the total staff can be reduced from 270 to 193 staff accordingly[18]. MIT performed a detailed bottom-up study with over 200 staffing categories and estimated 319 total staff for the 12-unit NuScale plant which is close to their initial estimate. In summary, for advanced reactors, given their simplification in safety, they are expected to reach staffing levels between 200-400 staffs. This study for a greenfield reactor found reaching

[18] Based on email exchange with Christopher Colbert, Chief Financial Officer & Chief Strategy Officer for NuScale on June 28, 2021.

below 300 staff may not be feasible unless advanced digitalization or other similar technologies, such as what is supported by the ARPA-E GEMINA program, are adopted which is beyond the current and near-term capability and regulatory acceptance. As such, 300 total staffing which is the approximate median of the reported numbers is assumed as baseline total staffing for a modern nuclear power plant.

The number of staffing for the additional unit is another cost component that requires addressing before the O&M cost estimation of SMRs can be made. The NGNP supplier and INL estimated that the additional unit will only require 15% and 19% of the first unit staff size, respectively (25 and 71 staffs). This is much lower than industry estimates for LWRs, where additional unit will require 60% of the first unit.[14] A value of 40% of the first unit (between NGNP and LWR estimates) is used to calculate the SMR O&M cost of multi-unit sites. For simplicity, the average staffing salary (instead of specific cost per category in Table 1) of the existing fleet is used to calculate the levelized O&M cost. This gives ±7% accuracy compared to the bottom-up approach across range of 150-1000 MWe power range for the Gen II LWR, where data is available. Table VI represents these costs as function of power level and number of units including recreating AP1000 O&M cost with the more simplified methodology.

Table VI. O&M Cost Estimate in $/MWhre for SMRs compared to AP1000 based on average staff salary of existing fleet.

Plant Size (MWe)	**150**	**300**	**600**	**1000**	**AP1000**
1 unit	77.3	38.7	19.3	11.6	13.1
2 units	63.4	31.7	15.8	9.5	10.3
4 units	56.4	28.2	14.1	8.5	8.8

Table VI implies that 2-unit and 4-unit AP1000 can achieve =<$10/MW/hre. This is further supported by the top Q1 O&M cost of existing fleet at $16.8/MWhr.[13] Given the significant simplifications in AP1000 plant, 20% reduction over the 50-year-old GENII technology in O&M is well within reach. For SMRs, the situation is much grimmer as they sacrifice substantial economy of scale. On a per unit basis, the US LWR and HTGR SMR range from 77-300 MWe. At this range, the O&M will be greater than existing fleet even with significant reduced staff (300 vs. 600). For the support and services category, there is not one or few SSCs that dominate the cost as such it is hard to conceive further reduction is possible unless new operational paradigms and technologies are considered. Another important finding from performing this exercise is the sensitivity of the total staffing to the fraction of total O&M cost that is made up of fixed cost. For a 300 staff plant, fixed cost makes up 40% of the cost while for a 200 staff plant it is 50% of the cost. Fixed cost is dominated by support and services and regulatory/operational fees. The fixed regulatory/operational cost are already greater than $10/MWhre for 150 MWe plant. Similarly, the support and services costs accounts for 23% of O&M cost. For a plant like NuScale, where 6-12 separate turbomachinery are designed, while it is conceivable to at best share the fixed regulatory fees among each unit, the support and services cost will be incurred per unit, rather than per plant.

For fuel cost, in case of SMRs, the cost is dependent on specific design. Most SMRs feature core power densities of <70% of large water reactors. So, their fuel cost is in range of $6.15-$9/MWhre. For non-LWRs, the fuel cost can be substantially higher. For instance, for HTGR and SFRs the fuel LCOE is closer to $15/MWhre[8] with large uncertainty given the world-wide lack of existing supply chain for high-assay low enriched fuel for commercial applications.

In summary, on an LCOE basis, the near term proposed SMRs feature substantially higher cost than large water reactors for greenfield deployment driven first by significantly higher O&M cost, followed by noticeably higher overnight cost. In the particular case of an existing nuclear plant site and high financing costs, single unit LWR SMRs that are designed with at least a core power density that is close to their large reactor counterpart[19] could provide investment incentives (e.g., BWRX300 300 MWe SMR in Canada). Otherwise, for SMRs that are housed under one reactor building (e.g., NuScale), which requires the reactor building construction to be completed before the reactor module placement, the benefits of reduced construction risk are lost. Additionally, if governments want to lead large decarbonization efforts, it makes sense to invest in a fleet (>8 orders) of large LWRs for the most economic and impactful option.

[19] Halimi A., Shirvan K., "Impact of core power density on economics of a small integral PWR," Nuclear Engineering and Design, Volume 385, 15 December 2021, 111488 [Link]