Advanced Nuclear Power Program

2024 Total Cost Projection of Next AP1000

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ABSTRACT

This report serves as an update to the previous report (in 2018 USD) on an independent assessment for the cost of the next AP1000 (1150 MWe Generation III+) compared to competing large and small modular reactor (SMR) technologies. Vogtle 3&4 have now been successfully in operation and overall have posted reliable operating record. The updated 2024 USD projection for the cost of next 2 AP1000s at Vogtle site is estimated to be between $8,300-$10,375/kW for overnight capital cost with construction schedule of 80-96 month from first nuclear concrete to commercial operation date. Lifetime Levelized Cost of Electricity (LCOE) of $78-$97/MWhre (2024 USD) is estimated, with help of federal loan guarantees (6% LCOE savings) and Investment Tax Credit (ITC) of 30% by Inflation Reduction Act. Notably, this cost aligns well with recent valuations of 24/7 carbon-free electricity for data centers and manufacturing facilities, and competitive with the cost of firming renewables, according to 2024 Lazard (>$150/MWhre in certain regions) and other grid studies. However, additional subsidy is required to not increase customer rates from current national average of price of about $65/MWhre (with large region, hourly and seasonal fluctuations), particularly during the financing period. However, with the 2024 USD estimated Nth-of-a-kind (NOAK) overnight cost and unsubsidized lifetime LCOE of $4,625/kW and $66/MWhre, respectively, AP1000 is uniquely positioned to provide substantial amount of baseload while deeply decarbonizing the electric grid at the current average price point. As such, a consortium of regional utilities is projected to be able to deploy about 20 GW of AP1000 by 2060 if both ITC and $15/MWhre production tax credit is extended till 2045. Nuclear deployment would also avoid over capacity build out for renewables and owners can leverage their low incremental added intermittent cost (e.g., utility PV at $30-$92/MWhre.- Lazard, 2024).

For a 300 MWe water-cooled Small Modular Reactor (SMR), NOAK LCOE increases by approximately 45% to $95/MWhre. Unlike renewables and battery storage that can be incrementally deployed, SMRs still involve lengthy construction process. As such, if owners are constrained in financing capital for AP1000 plants, deploying a similar capacity in parallel .i.e. fleet of SMRs, exacerbates the challenges associated with securing financing. Nevertheless, full decarbonization of U.S. electricity grid has been projected by many studies to increase cost of electricity generation to at least $100/MWhre, where NOAK SMR can play a pivotal role in providing seasonal production backing to intermittent renewables and short-term battery storage. Despite such potential and the fact that water-cooled reactors are the dominant technology for domestic and export markets, direct subsidies for water-cooled reactors have taken a back seat to non-water designs among U.S. policymakers. The certified technologies such as the AP1000 and APR1400 have already addressed their FOAK challenges and have higher potential to address near term growing carbon-free energy demands. As of 2024, there are no new power sources that can deliver 24/7 carbon-free electricity year around and maintain current generation costs, and therefore providing the projected subsidy to achieve NOAK offering is strongly recommended.

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Executive Summary

This report serves as an update to the previous report on an independent assessment for the cost of the next AP1000 (1150 MWe Generation III+) compared to competing large and small modular reactor (SMR) technologies. The baseline projection in the last report was performed in 2018 USD and was before the passage of the Inflation Reduction Act (IRA) and successful commercial operation of the two AP1000s (Vogtle 3&4) in the U.S. The previously noted independent cost projection of first-of-a-kind (FOAK) Vogtle 3&4 was $32 billion (2018 USD) and a 130-month construction schedule, seemingly very close to the estimated final realized cost: $35 billion in 2023 USD[1] and schedule: ~130 month. Meanwhile, China launched construction of 6 additional AP1000 reactors, recognizing the operation and maintenance benefits that were discussed in the previous report and now realizing gains in their construction schedule in-line with the predictions in the previous report. The previous projection for the overnight capital cost of the next AP1000 (without owner's cost) ranged from $4,300/kW to a high-end estimate of $6,800/kW in 2018 USD accounting for a post-COVID rise in cost of commodities and labor rates. The 2018 USD was reported as it both represented the mid-point of Vogtle 3&4 construction and assumed the post-COVID rise would be temporary. However, inflation has continued to persist while the demand for large-scale dispatchable carbon free energy has increased significantly, particularly in southeastern U.S. The impact of at least 30% investment tax credit (ITC) from IRA, which would obviously be preferred over the production tax credit provisions, will have a significant impact on the economics of AP1000 and nuclear energy against displacing other baseload carbon emitting generation. Therefore, a more refined and precise projection for the cost of the next AP1000 compared to the latest projections of other competing nuclear technologies is highly desirable.

By dissecting the cost overrun realized in the Vogtle project through a bottom up approach, the key features that contributed to cost and schedule overrun that will likely not be repeated is quantified within an uncertainty range. It is found that as much as a 45% decrease in overall engineering, procurement and construction (EPC) could be made, reducing the total overnight cost by 40%. This reduction is mainly driven by (in order of importance), lack of experienced personnel, a new regulatory certification process and an incomplete design, accounting for 65% of the improvement. Other leading factors include (in order of importance), supply chain delays, overall learning through finishing the existing 2 units for both the owner/operator and original EPC provider and avoiding bankruptcy by the original EPC. Substantial cost savings could have been realized if the next units were sequentially constructed at the same site, however, it is not expected NOAK cost and schedule numbers will be achieved with the next offering, which in reality represents the 2nd offering of AP1000 in the U.S. As such, including owner's cost, an overnight

[1] ~$35 Billion derived from Vogtle 3 & 4 Project January 2024 update total cost by GPC divided by 0.457 which is share of GPC of the total project. Financing cost and cost recovery by non-GPC owners are simply estimated to be same as GPC.

cost of \$8,300/kW for the next 2 units of AP1000 with construction schedule of 80 months is projected, with no additional contingency included. Going to 4 units, can reduce the cost to \$7,500/kW since much of the owner's cost can be shared and limited learning within units can be realized. These values are subject to an additional 25% of contingency, given the "mega-project" attributes of large nuclear construction and unpredictability in construction productivity (including work force recruitment) and potential supply chain delays. Additional owner's cost should be escalated relative to the projected cost and schedule if the additional AP1000s are to be built in other sites than Vogtle. The capital cost of subsequent units has potential to approach AP1000s NOAK should cost of \$4,750/kW (with assumed Owner's cost of \$1000/kW) in 2024 USD.

Table I implies if Vogtle 3&4 would have been built today as FOAK plants, then LCOE of \$257/MWhre would be realized. Accounting for an 80-year expected lifetime and 30% ITC and a low-interest loan guarantee that can be provided by Department of Energy's Loan Program Office (LPO), LCOE of \$147/MWhre is estimated. This provides the upper limit for LCOE for next AP1000 if it has the same poor construction experience as Vogtle did. Table I also shows that the unsubsidized LCOE during 30-year financing period and lifetime for the next 2 AP1000s is estimated to be in the range of \$128 to \$189/MWhre, and \$112 to \$163/MWhre, respectively, based on assumptions on contingency and greenfield site (upper bound). Such values are in same range or lower compared to the noted unsubsidized "firming cost" of solar PV and PV plus storage in CAISO (California) and PJM (East coast) markets of \$106 to \$162/MWhre [Lazard 2024], respectively, even though the firming cost still does not provide a 24/7 dispatchable carbon-free source of electricity similar to AP1000. When comparing NOAK AP1000 to more competitive markets such as ERCOT (Texas) and MISO (Midwest), NOAK AP1000 at \$66/MWhre is competitive with their firm LCOE for PV of \$78 to \$100/MWhre. Similarly, NOAK AP1000 unsubsidized lifetime LCOE is competitive with the projected cost of Combine Cycle Natural Gas with 97% Carbon Capture and Sequestration (CCNG+CCS) of \$82 to \$92/MWhre, even though such technology is still immature and its performance is more uncertain than AP1000. In addition, nuclear is eligible for higher subsidy under the IRA than CCS technology that is also used for firming Solar PV, since it does not emit any carbon and combined with its higher readiness level and reliable operation experience of AP1000 in U.S. and China (unlike CCNG+CCS poor operating experience in the U.S. thus far[2]), AP1000 provides an attractive alternative. Another important finding from Table I is that with **NOAK unsubsidized LCOE of \$73/MWhre during the 30-year financing period, AP1000 will provide similar generation cost as the current ~\$65/MWhre electricity generation cost[3], very close to AP1000 lifetime unsubsidized LCOE (\$66/MWhre). This means deep decarbonization can economically be done with AP1000**

[2] https://www.geoengineeringmonitor.org/2022/12/the-current-state-of-ccs-in-the-u-s-resume-after-100-years-of-co2-capture-and-25-years-of-extensive-federal-funding/

[3] https://www.eia.gov/todayinenergy/detail.php?id=55139

while alternatives will only raise the cost of electricity.

Table I. Summary of AP1000 cases: Comparison of AP1000 vs. other firm clean energy sources (e.g., solar + battery/transmission based on Lazard Assumptions and CCNG with 97% CCS based on ATB database; "other firm clean energy" does not mean 24/7 or 100% carbon free as defined in Lazard 2024, therefore comparison is conservative). All costs are 2024 USD; Unless noted, values are $/MWhre using ATB 2024 assumptions (50/50 Debt/Equity Financing); Baseline V3&4 realized represents Vogtle 3&4 estimated realized overnight cost (assumed PTC of $15/MWhre till 2034 under Ave W/ITC/PTC) while Baseline V3&4 if built today represents Vogtle 3&4 if built today in 2024 USD (assumed ITC under Ave W/TIC/PTC); All costs include owner's cost; 30/50: refers to 30 years for capital cost pay back and additional of 50 years operating with only O&M, fuel and refurbishment/relicensing cost; LPO loan savings applied to all AP1000 cases under W/ITC/PTC except NOAK case; *ITC/PTC is assumed to be expired.

Cases	**Capital, O&M and Fuel Cost Projections**				
	Baseline (V3&4 realized)	Baseline (V3&4 if built today)	Next 2 @ Vogtle	Next 2 @ Green Field	NOAK
Capital ($/kW)	$11,000	$15,000	$8,300 – $10,375	$9,300 – $11,625	$4,625
Capital	$158	$229	$105-$141	$123 -$161	$52
O&M	$19	$19	$14	$19	$12
Fuel	$9	$9	$9	$9	$9
Total	$186	$257	$128-164	$151-189	$73
Refurbishment	$6.25	$6.25	$6.25	$6.25	$6.25
Cases	**Lifetime Average**				
Average (30/50)	$169	$220	$112-142	$132-163	$66
Ave W/ITC/PTC	$154	$147	$78-97	$92-112	$66*
2024 PV + Storage Firm Unsubsidized Cost (Lazard)	$162-$160 (CAISO & PJM)	**2024 PV Firm Unsubsidized Cost (Lazard)**	$106-$153 (CAISO/PJM) $78-$100 (MISO/ERCOT)	**2024 CCNG with CCS (ATB – 2050 Projection)**	$82-$92 (80% capacity factor and 25% contingency for higher-end)

The major drawback of AP1000 in Table I is that it will increase consumer electricity prices before reaching NOAK performance unless additional subsidy is provided. However, there are two fundamental flaws in using this drawback to not build fleet of AP1000s by utilities:

1. Decarbonization cannot take place with maintaining the current electricity generation LCOE. As shown in Table I, other less firm sources of carbon free electricity actually cost higher than the next AP1000 lifetime LCOE and will significantly increase the national price average upon large penetrations. In fact, each added capacity of intermittent generation will make the additional capacity less valuable and increase the total generation cost as shown by several studies.
2. Renewable technology has benefited from sustained subsidy over the course of more than 20 years in the U.S. and has attained NOAK economics. As shown by Table I, AP1000 at its NOAK lifetime cost ($66/MWhre) can actually maintain the average electricity generation cost at the

current national average. Therefore, it is clear that to achieve both decarbonization at an affordable price, the government needs to provide the same subsidy that it provided for renewables prior to IRA until AP1000 reaches its NOAK and can stand on its own vs. other firm carbon-free sources even during its financing period. Unfortunately, IRA only provides similar subsidy on per MWhre bases, rather than providing subsidy on the commercial offering (e.g., X-OAK) of the technologies.

Finally, a similar analysis for a 300 MWe water-cooled SMR was performed. Several conclusions were made by comparing the SMR deployment with a 23 GWe AP1000 deployment over the period of 2024 (accounting for Vogtle 3&4) to 2060:

1. It is ill-advised to deploy 4-unit FOAK as FOAK risks will propagate across all four units
2. SMR realized a higher learning rate but its NOAK was still ~45% higher than NOAK AP1000
3. About factor of 2x higher O&M cost for the SMR raises its unsubsidized NOAK lifetime LCOE to $95/MWhre, which is still competitive with costs of alternative sources noted in Table I.
4. 7 GWe phased deployment of the SMR by 2060 provides significant reduction in financed capital and potential cost escalation risk to the utility, its shareholders and rate payers compared to AP1000.
5. 23 GWe SMR route by 2060 equates to 75 reactors. The construction schedule for each reactor is estimated to be shorter but on the same range as the AP1000. This would mean substantial parallel construction will be required to meet targeted capacity which would lead to requiring financing even higher total capital compared to AP1000 and put the owner at more risk.

Therefore, the retiring fossil generation and the recent growth in the electricity demand for main grid applications will likely be met by large reactors than SMRs, if sufficient support is provided. Meanwhile, NOAK SMRs still provide a competitive firm clean energy source relative to non-nuclear alternatives to support deep decarbonization.

It is finally noted that the subsidized Korean U.S. certified technology, APR1400, could be an alternative to the AP1000. While the "should" cost of AP1000 is lower than APR1400, the Korean government has incurred massive debt to finance its nuclear energy program and will likely continue to do so if it opens the door to the U.S. electricity market. The EP provider of AP1000, Westinghouse, is currently Canadian-owned, therefore the U.S. government is likely disincentivized to match the Korean government subsidy for AP1000. For the same reason, it will be difficult for the AP1000 to compete against Korean, French, Russian and Chinese technologies on the international market. Despite the impression given to U.S. policy makers, these countries continue to export water-cooled technology using low-enriched uranium and as such it is in the best interest to U.S. national security to also support water-cooled technologies such as AP1000 in the export market. Given 10 years of IRA is not enough for AP1000 or other nuclear technologies needing additional $25 billion per technology to reach their attractive NOAK potential, additional subsidy is needed from government on the same scale as it was provided to renewables to allow realization of NOAK cost**. This policy recommendation is critical for realizing an economic decarbonization plan in U.S.**

I. Background

Globally, out of 57 reactors under construction today (July 2024), 51 reactors are large 1000 MWe+ water-cooled type, 2 are small water cooled and 4 are liquid metal-cooled.[4] All the non-large water reactor projects (commonly referred to as "Advanced Reactors") are domestic government-led programs using host country technology as they are not being exported internationally. The 1000 MWe+ class of Generation III/III+ nuclear power plants available for new construction include the light water reactor (LWR) technologies such as AP1000 (1150 MWe), EPR (1650 MWe), APR-1400 (1450 MWe), VVER-1200 (1200 MWe), Hualong One (1000 MWe) and ABWR (1350 MWe). Recently, in response to clean energy demand in the providence of Ontario, a 1000 MWe heavy-water cooled reactor, Monark, is also being developed to join this Gen III/III+ group. All these reactors use Uranium enrichment ranging from natural (0.7%) to 5% enrichment which is commercially available**. Therefore, for global nuclear commercial enterprises, water-cooled technology and low-enriched uranium (LEU) fuel holds the center stage for nuclear energy growth.** In this list, only the AP1000 by Westinghouse, ABWR by Hitachi-GE and Monark by Atkinson are privately led, where large risk and loss cannot financially be absorbed. This severely hinders the wide commercial penetration of these technologies in international markets as it is *very challenging* to compete with heavily subsidized Russian, Chinese, French and Korean technologies.

In the U.S., there have been only three new reactors deployed in this century: Watts bar Unit 2, a 4-Loop Westinghouse Pressurized Water Reactor (PWR) which was finished in 2016 and Vogtle Unit 3 and 4 AP1000 which were connected to the grid in 2023 and 2024, respectively. All three reactor units experienced both cost overrun (>2x) and schedule delays (>3 years). Meanwhile, the U.S. government has been spending the majority of its direct funding for new nuclear energy on licensing SMRs and non-LEU fuel development for non-water cooled reactors. On one hand, one could argue the realized cost overrun and schedule delay would mean the government should push alternative technologies as more economic solutions. On the other hand, Giga-watt sized reactors have proven to be the preferred route on the global stage, since the SMR technologies considered were largely tried and abandoned in the past.[5] The current trajectory of U.S. government direct funding support continues to be on SMRs and non-LEU fuel. Meanwhile, all carbon-free source of energy is eligible to receive subsidy and loan guarantees from the U.S. government as part of the Inflation Reduction Act (IRA). Unless large water-cooled reactors can stand on their own compared to alternative means

[4] https://pris.iaea.org/PRIS/WorldStatistics/UnderConstructionReactorsByCountry.aspx
[5] https://world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/nuclear-power-reactors

of carbon-free energy (solar, wind, storage, carbon capture and sequestration (CCS)), given limited international penetration of North American technologies from the mentioned lack of strong government support and ownership, *the U.S. will not contribute significantly to world-wide new nuclear energy generation.*

Currently, the main large water-cooled reactor that is licensed and domestic to north American and being actively advertised to north American customers is the AP1000 technology by Westinghouse which is now a fully Canadian-owned entity. Therefore, understanding what is the next AP1000 cost is crucial for North American energy utilities and will answer the question of whether the U.S. will add new nuclear energy generation. In the previous report, the AP1000 cost was predicted in 2018 USD as it represented the mid-point of its construction at the Vogtle site in the U.S.[6] This report focuses on projecting the 2024 USD cost for a multiple-plant configuration. Independent analysis has been performed to first calculate the overnight cost of the Vogtle 3&4 plants in 2024 USD. Then, sources of cost reduction for the next AP1000 are projected. The success of AP1000 will depend on the economic performance of alternative carbon-free technologies, including SMRs. This report updates the previous comparison given the development of the last three years. It should be noted that KHNP has recently started advertising the APR1400 to U.S. customers. Unless the U.S. government provides additional subsidies for the AP1000, the contract price for APR1400 will be favored over AP1000, even though the should cost for the technology is higher simply based on significantly higher material use and number of components per MW produced.[3]

[6] https://web.mit.edu/kshirvan/www/research/ANP193%20TR%20CANES.pdf

II. Cost of Vogtle Unit 3 and 4 in 2024 USD

Readers should refer to the previous report for definitions and terminology used in this section.

Overnight Cost

The Vogtle Unit 3 and 4 project was executed between 2007 to 2024. The consumer price index (CPI) from 2007 Q1 to 2024 Q1 changed by 1.55x.[7] The CPI is a reasonable way to look at nuclear cost escalation as it matches closely with the average of escalation of essential craft labor including iron workers and electricians as utilized in the bottom-up cost escalation methodology of MIT's Nuclear Cost Estimation Tool (NCET).[8] The Georgia public commission release of the finances of their portion of Vogtle Unit 3 and 4 was used and linearly scaled to estimate the 100% value. It is estimated that \$2,500/kW was spent before the first nuclear concrete pour in 2013 and \$3,500/kW and \$5,000/kW was spent for each of the next 5 years of construction, respectively, for a total overnight cost of about \$11,000/kW (GPC Jan 2024). This is consistent with the prediction of the overnight cost in the previous report, giving some confidence in the projections for this report.[3] Inflating this cost based on CPI on a yearly basis, results in overnight cost of about **\$15,000/kW**. This serves as a baseline overnight cost to develop an estimation for the next AP1000 cost reductions. Additionally, according to Georgia Power (GP), the original EPC was 27% while the Owner's cost was 14% of the total overnight cost. Owner's cost typically includes site preparation and cooling (including utility access), additional transmission switchyard, site specific engineering and regulatory compliance.

Financing Cost

The Vogtle Unit 3 & 4 AP1000 financing is quite complex given the combination of loan guarantees, rate payer reimbursement and a longer than 10 years of project period. According to GP, the total project cost including financing cost was \$18,500/kW (an additional of \$3,500/kW) or 1.23 multiplier on the overnight cost. For an independent estimate of a 2024 financing cost of AP1000, selected assumptions from 2024 Lazard report[9] and equations from NREL 2024 database are integrated[10]. Financing

[7] https://www.usinflationcalculator.com/inflation/consumer-price-index-and-annual-percent-changes-from-1913-to-2008/
[8] https://canes.mit.edu/capital-cost-evaluation-advanced-water-cooled-reactor-designs-consideration-uncertainty-and-risk
[9] https://www.lazard.com/media/gjyffoqd/lazards-lcoeplus-june-2024.pdf
[10] https://atb.nrel.gov/electricity/2024/equations_&_variables

multiplier of 1.48 during construction is calculated according by assuming 50% debt fraction, at rate of 6.5% with equity rate of return of 12.5% at constant inflation rate of 2.5%. This factor is higher than 1.23 multiplier reported by GPC by a factor of 1.2. When accounting for potential support from the Loan Program Office (LPO)[11], a factor of 1.06x of this multiplier is estimated to be from loan guarantees that would reduce the debt rate from 6.5% to 5.4%. The remaining is assumed to be due to ability of a regulated utility to recover its cost during construction by passing it to the ratepayers. However, for the remaining parts of the report, no cost recovery during the construction is assumed and the LPO loan guarantees and IRA tax benefits are applied for all projects till 2032 for the subsidized cost numbers. The Lazard 2024 report also provides a new build LCOE for nuclear power plant. Using the same input costs as Lazard (in particular, increasing tax rate from 27.5% to 40%) to the LCOE model, LCOE of $225/MWhre is obtained compared to the reported $222/MWhre for the nuclear upper bound. This means that the method used in this report seems to be consistent with Lazard, as such comparing unsubsidized AP1000s to other energy sources reported in Lazard could provide useful insights. Overall, for every $1000/kW, $13.6/MWhre is added in addition to interest during construction multiplier. The LPO reduces this to $12.8/MWhre and 30% ITC reduces it to $8.4/MWhre.

O&M and Fuel Cost

We can utilize the latest data by Nuclear Energy Institute for LWRs in regulated markets to calculate AP1000 O&M and fuel cost for Vogtle: $35.35/MWhre in 2023 USD.[12] In the previous report, it was noted that the AP1000 has potentially very attractive features to reduce O&M. These projected features have now been validated by the excellent operation of AP1000s, achieving the highest capacity factors in the Chinese fleet and motivating additional construction of multiple AP1000 (Currently 6 additional units are under construction in China).[13] This new empirical evidence gives additional confidence in the projections of this report. As such, the cost saving potential predicted in the previous report is applied to the latest fleet O&M and fuel cost resulting in ~$28/MWhre. This number on one hand, is conservative as it includes $6.25/MWhre cost of capital investment which is currently being made for existing fleets for license extensions which will not be applicable immediately for AP1000s during its first 20-40 years of operation. On the other hand, the fuel cost is underestimated for future reactors given the large sustained increase in Uranium prices and the typical 10 to 15 years needed to achieve

[11] https://www.energy.gov/lpo/articles/how-loan-programs-office-and-plant-vogtle-are-shaping-energy-transition-through
[12] https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context
[13] https://world-nuclear-news.org/Articles/China-approves-construction-of-four-new-reactors

equilibrium fuel cycle economics. As such, it is assumed that these effects are canceling (likely conservative) and $28/MWhre is utilized for baseline FOAK AP1000 in 2024 USD for O&M and fuel cost.

Levelized Cost of Electricity

Utilizing the referenced 2024 NREL equations and noted financing assumptions, LCOE of $229/MWhre for capital cost and total LCOE (plus O&M and fuel) of $257/MWhre if Vogtle 3 & 4 were to be built today in 2024 USD for 30 year financing is estimated. This should not be confused with the actual LCOE projected for the plants. If we use the GP capital cost numbers with the $28/MWhre O&M, LCOE of $186/MWhre for current Vogtle 3&4 is obtained (not accounting for loan guarantees and cost recovery). The $257/MWhre figure is only valid for 30-years during which the capital cost is paid back. For the next additional 50 years (potentially additional 70 years), the LCOE of FOAK AP1000 would only be the $28/MWhre. This would yield to an average LCOE of $220/MWhre over 80 years. The averaging is done by applying WACC to the net present value of the system over 80 years. The estimated realized lifetime LCOE (also given its eligibility for PTC for next 10 years) is at most $154/MWhre. According to Lazard 2024, when adding the cost of firming to renewables, the FOAK AP1000 cost "if built today" is significantly higher in all markets against its reported firm cost of renewable, in particular solar PV plus storage as seen in Table 1 that will be discussed in more detail in the next chapter. While the estimated realized lifetime LCOE is actually inline with certain market costs. As explained in the Lazard 2024 report, the firming cost by no means includes a 24/7 storage and dispatch capability for renewables which the AP1000 has shown thus far. A highly cited study in 2018, estimated cost of zero carbon electricity in the U.S. without nuclear to be between $100/MWhre to $300/MWhre, depending on the region (availability of renewables) and cost assumptions on electricity storage.[14] Therefore, while the GP customers will pay a premium on their electricity bill in the years to come, once the capital cost is paid for, their bills will actually be lower while moving in the right direction in terms of decarbonization targets. Also, GP customers would have paid a similar or higher premium if equivalent firm clean energy was deployed according to today's cost of renewables plus long term strroage is deployed over the next 80 years. Nevertheless, both the realized and todays cost of FOAK AP1000 is quite unattractive, particularly during its 30-year financing period.

[14] https://doi.org/10.1016/j.joule.2018.08.006

III. Cost of Next AP1000 in 2024 USD

There are several areas of cost reduction for the next AP1000 reactor offerings. Recently, Stewart and Shirvan[15] explored the impact of onsite inefficiencies, regulatory hurdles and supply chain delays probabilistically on cost overrun for different reactor architectures. The risk to cost overrun was quantified through impact on construction schedule. Distributions were assumed such that most of these inefficiencies are removed after FOAK construction. Then bottom-up learning models discussed in the previous report, can be applied to estimate the next plant offering cost and schedule. Starting with that analysis methodology, a generic model of AP1000 was modeled and schedule savings were estimated. It is important to note that in reality if delays are overlapping, solving one delay will not appreciably change the overall schedule. As such, the estimations below are only applicable if they are accumulated together and not individually.

Savings due from learning-by-doing are estimated to be $2,900/kW in 2024 USD:

1. Supply chain and procurement: In Vogtle Unit 3&4, original EPC is estimated to have experienced an additional procurement cost of $2,000/kW. $700/kW savings is estimated based on 12-month savings from both on-time delivery of module parts (both equipment and civil including steel-plate composite) and reduction in civil rework as experienced in the construction of shield building.[16]
2. Onsite Personal Lessons Learned from Lack of Experience: In Vogtle Unit 3&4, original EPC is estimated to have experienced an additional cost of $4,000/kW in construction services. $1,500/kW of this is estimated based on 30-month savings in the construction schedule for the next unit. This is based on the efficiencies observed from Unit 3 to Unit 4 in construction and commissioning as reported by GP. Over half of inefficiencies are expected to resolve from FOAK to 2nd-OAK if the same laborers would construct the next AP1000 using the available detailed plan for the construction sequence. Given the total project took over 10 years and the construction contractors would change, both the personnel and data on inefficiencies will not be fully resolved and as such the savings is adjusted accordingly.
3. Nuclear learning-rate: The bottom-up learning rate found under a consistent regulatory framework on standardized nuclear design was found to be between 8 to 15% for LWR and

[15] https://doi.org/10.1016/j.nucengdes.2023.112305
[16] https://www.wamstedonenergy.com/2016/time-for-a-reality-check-more-delays-are-coming-for-georgia-powers-new-vogtle-reactors

SMR nuclear plants based on previous studies by Stewart & Shirvan[17]. For the AP1000, given its architecture, the assumed level of modular construction similar to what was realized in Vogtle Unit 3&4, a value of about 10% is estimated. Therefore, a cost savings of $700/kW from a schedule savings of 13 month was estimated for the next 2-unit AP1000 offering.

Savings unique to Vogtle Unit 3&4 that would be realized for any future AP1000 offering are expected to be $3,800/kW:

1. Savings by having a complete design and work package: Several studies have pointed out that an incomplete design can lead to significant cost and schedule overruns.[18] Following the methodology by Stewart & Shirvan, it is assumed design change orders would not occur if the design is fully complete. Savings of about $1000/kW from a 19-month schedule delay is estimated. The design changes are broken up as 30% civil work and 70% equipment installation with electrical installation as the leading contributor to savings. It is not logical to assume no change orders will take place in the next 2-unit construction of AP1000 given the megaproject complexities. This will be addressed later with the addition of contingency.
2. Savings by completing for first time the 10CFR50.52 licensing framework: As noted in the previous study, 188 license amendment resulted in delay and productivity losses. A savings of $1,600/kW is based on 28-month savings by assuming most of the productivity losses were due to license amendments. There is strong empirical evidence that shows a correlation between productivity loss and increased regulatory oversight in the history of U.S. nuclear construction.[19]
3. Savings by not changing EPC lead due to bankruptcy: Based on the public information on the Vogtle site, there is about a 10-month schedule delay due to switching and re-planning. This results in savings of $500/kW.
4. Savings by building 2 units on the same site with an existing nuclear power plant: 30% savings on Owner's cost or $600/kW is expected by building the units on the same site (less training required) at a reduced schedule (less time spent on oversight).

Accumulation of savings is found to be $6,700/kW for the next 2 unit AP1000 leading to overnight cost $8,300/kW with $1500/kW of this value assumed to be Owner's cost. For a greenfield site, at least an additional $1000/kW of an owner's cost is estimated. The addition of 2 more units can reduce this cost to $7,500/kW due to sharing of owner's cost and some field work as well as additional learning

[17] https://doi.org/10.1016/j.rser.2021.111880
[18] https://www.oecd-nea.org/upload/docs/application/pdf/2020-07/7530-reducing-cost-nuclear-construction.pdf
[19] https://ifp.org/nuclear-power-plant-construction-costs/

on the construction site. For the 2-unit plant, at a $8,300/kW labor rate, a construction schedule (first nuclear concrete to commercial operation) of 80-month is estimated. As a point of reference, the FOAK AP1000 in China and the U.S. were built within 1 year of each other, while most task productivity were on the same order. The estimated schedule using NCET is about 2 years longer than the 2nd series of AP1000 being constructed in China on a 60-month construction schedule which has been on-time so far. For instance, the placement of the reactor pressure vessel was 2x faster than any prior AP1000 attempts (only 18 months after start of construction).[20] The impact of lower shift hours per day in the U.S. and China will also result in discrepancy among the two estimates. It is likely that the 3rd series of AP1000s will approach this schedule if a trained workforce and supply chain are directly utilized for the next part instead of the current gap in construction. For O&M (without capital cost of refurbishment), utilizing the previous report methodology, $14/MWhre is estimated for the next AP1000. For fuel cost, the fuel cost of 2012 is utilized given the current uranium price projections: $9/MWhre.

After 30 years of financing, capital cost of $6/MWhre is added for refurbishment, regulatory and other activities. Power uprate potential of 2% after 20 years and 5% after 40 years can also be assumed to be consistent with industry trends and AP1000 potential. It is likely that a larger power uprate could be attained if the NRC approves a more risk-informed loss-of-coolant accident than existing fleet is pursuing is adopted. Afterall, power uprate of existing fleet is the only way to add new nuclear to the grid and meet the ever-growing demand in this decade.[21] Without considering power uprate potential, over 80-year lifetime, accounting for the noted contingency, the LCOE of the next 2-unit AP1000 is estimated to be $112-142 and $78-$97/MWhre, without and with subsidy, respectively. This is an attractive LCOE when compared to alternative dispatchable carbon-free sources as noted in Table 1. The noted unsubsidized firming cost of solar PV and PV plus storage in CAISO (California) and PJM (East coast) markets are$106 to $162/MWhre, respectively, even though the firming cost still does not provide a 24/7 dispatchable source of electricity similar to AP1000. When comparing to more competitive markets such as ERCOT (Texas) and MISO (Midwest), the next AP1000s are higher compared to their unsubsidized firm LCOE for PV of $78 to $100/MWhre. Similarly, these unsubsidized lifetime LCOEs for the next AP1000s are estimated to be higher compared to unsubsidized cost of Combine Cycle Natural Gas with 97% Carbon Capture and Sequestration (CCNG+CCS) of $82 to $92/MWhre. However, such technology is still immature and cost comparison to NOAK AP1000 is more consistent. In addition, nuclear is eligible for higher

[20] https://world-nuclear-news.org/Articles/Haiyang-3-reactor-vessel-lifted-into-place
[21] https://osf.io/preprints/ykxh4

subsidies under the IRA than CCS technology since it does not emit any carbon and combined with its higher readiness level and excellent operation experience of AP1000 in U.S. and China (unlike CCNG+CCS plants in the U.S.), the AP1000 provides an attractive alternative. While the price of energy storage (e.g., batteries) continues to decline, each addition of intermittent solar and wind capacity will increase their firming price.[14] It is assumed that these two effects cancel each other out.

Another important finding from Table 1 is that with **NOAK LCOE of $73/MWhre during the 30 year financing period, AP1000 provides a competitive price point against alternatives** that do not have the potential to provide 24/7 reliable carbon-free electricity. This further incentivizes the public and private sector to push deployment of future AP1000s to realize its NOAK economics. Finally, there are currently discussions about implementing cost overrun insurance based on a 50/50 cost share split for nuclear projects. The value of this insurance for the next 2 units would equate to $13-$18 billion dollars if we assume added contingency as cost overrun. As shown, during the 30-year period, the PV firm cost lies between the bounds of the next 2 AP1000s. Therefore, additional cost overrun insurance or a cost share program offered by the federal government could be critical for the utilities when making technology decisions.

The major drawback of the AP1000 in Table 1 is its high LCOE during the 30-year financing period. The addition of a 25% contingency as well as a greenfield makes it unattractive relative to alternatives for that period and will raise customer rates even though in the long run there is a net benefit from decarbonization point of view and attaining the NOAK economics. The average electricity generation in the US based on different hubs in 2021 was around $65/MWhre (with large seasonal fluctuations).[22] The next 2 AP1000s would lose the company between $250 Million to $1,150 Million in net present value per year for its lifetime years ($20 to $92 Billion dollars of loss). As such, there are currently no over excitement to build AP1000s among the electric utilities in the U.S. However, there are two fundamental flaws in this path of no AP1000s:

1. Decarbonization cannot take place with maintaining generation LCOE at $65/MWhre. As shown in Table I, other less firm sources of carbon-free electricity actually cost higher than the next AP1000 lifetime LCOE and will significantly increase the national price average upon large penetration. In fact, each added capacity of intermittent generation will make the additional capacity less valuable and increase the total generation cost as shown by several studies.[14]

2. Renewable technology has benefited from sustained subsidy over the course of more than

[22] https://www.eia.gov/todayinenergy/detail.php?id=55139

20 years in the U.S. and has attained NOAK economics. As shown by Table 1, AP1000 at its NOAK cost ($66/MWhre) can actually maintain the average electricity generation cost at the current national average. Therefore, it is clear that to achieve decarbonization at an affordable price, the government needs to provide the same subsidy that it provided for renewables prior to IRA until the AP1000 reaches its NOAK and can stand on its own vs. other firm carbon-free sources even during its financing period.

The current dispatchable 24/7 clean energy is valued in many markets close to $100/MWhre given the challenge of achieving it with several fold over capacity in installment with renewables plus battery storage. A power purchase agreement at this price would make lifetime LCOE of next 2 AP1000s at existing nuclear power plant site with help of ITC and LPO an economic investment. At absence of this power purchase agreement or deployment at a greenfield site, it continues to be economically challenging to justify building of next 2 AP1000 without consideration of the big picture: attractive NOAK cost and higher cost of alternatives for the same valued carbon-free generation. As such, the government (both federal and state) must provide AP1000 technology with adequate subsidy to reach NOAK cost target. This subsidy is estimated to be composed by 30% ITC and added $15/MWhre production tax credit (PTC) till 2045 as inferred by Figure 2.

Table 1. Summary of AP1000 cases: Comparison of AP1000 vs. other firm clean energy sources (e.g., solar + battery/transmission based on Lazard Assumptions and CCNG with 97% CCS based on ATB database; "other firm clean energy" does not mean 24/7 or 100% carbon free as defined in Lazard 2024, therefore comparison is conservative). All costs are 2024 USD; Unless noted, values are $/MWhre using ATB 2024 assumptions (50/50 Debt/Equity Financing); Baseline V3&4 realized represents Vogtle 3&4 estimated realized overnight cost (assumed PTC of $15/MWhre till 2034 under Ave W/ITC/PTC) while Baseline V3&4 if built today represents Vogtle 3&4 if built today in 2024 USD (assumed ITC under Ave W/TIC/PTC); All costs include owner's cost; 30/50: refers to 30 years for capital cost pay back and additional of 50 years operating with only O&M, fuel and refurbishment/relicensing cost; LPO loan savings applied to all AP1000 cases under W/ITC/PTC except NOAK case; *ITC/PTC is assumed to be expired. CF: Capacity Factor

Cases	**Capital Cost Pay Back Period (30 Years)**				
	Baseline (V3&4 realized)	Baseline (V3&4 if built today)	Next 2 @ Vogtle	Next 2 @ Green Field	NOAK
Capital ($/kW)	$11,000	$15,000	$8,300 – $10,375	$9,300 – $11,625	$4,625
Schedule (m)	120	120	80-96	90-100	48
Capital	$158	$229	$105-$141	$123 -$161	$52
O&M	$19	$19	$14	$19	$12
Fuel	$9	$9	$9	$9	$9
Total	$186	$257	$128-164	$151-189	$73
W/ITC/PTC	$175	$169	$88-110	$104-127	$73*
Cases	**After Capital Cost Payback Period (>30 Years)**				
	Baseline (V3&4 realized)	Baseline (V3&4 if built today)	Next 2 @ Vogtle	Next 2 @ Green Field	NOAK
Capital ($/kW)	$0	$0	$0	$0	$0
Capital	$0	$0	$0	$0	$0
O&M	$19	$19	$14	$19	$12
Fuel	$9	$9	$9	$9	$9
Refurbishment	$6.25	$6.25	$6.25	$6.25	$6.25
Total	$34.25	$34.25	$29.25	$34.25	$27.25
Cases	**Lifetime Average**				
	Baseline (V3&4 realized)	Baseline (V3&4 if built today)	Next 2 @ Vogtle	Next 2 @ Green Field	NOAK
Average (30/50)	$169	$220	$112-142	$132-163	$66
Ave W/ITC/PTC	$154	$147	$78-97	$92-112	$66*
2024 PV + Storage Firm Cost (Lazard)	$162-$160 (CAISO & PJM)	**2024 PV Firm Cost (Lazard)**	$106-$153 (CAISO/PJM) $78-$100 (MISO/ERCOT)	**2024 CCNG with CCS (ATB)**	$82-$92 (80% CF/25% contingency for higher-end)

IV. Alternative Nuclear Technologies

The commercial viability of the AP1000 will also depend on the cost of alternative nuclear technologies as well as carbon-free technologies such as renewables and energy storage and their penetration level. In the previous report, the alternative nuclear technologies were shown to have higher cost projections when applying same methodology. This is an important point, as it concludes the AP1000 merits based on should cost. In the recent bid in Poland by WEC ($4,500/kW), the AP1000 is more expensive than the French EPR ($3,300/kW) and the Korean APR1400 ($3,200/kW).[23] Unlike EDF and KHNP, WEC is privately held, thus without government backing has no means to significantly underbid contracts compared to the other vendors. For instance, currently, KHNP has about $20 billion in debt[24] to yearly revenue of $8 billion dollars, while Westinghouse has $4 billion in debt to a similar yearly revenue of $8 billion dollars. EDF is both a utility and vendor fully-owned by the government and has been bailed out from bankruptcy more than once in the last 20 years. Therefore, for international markets, unless strong ties exist between the U.S. and the host country, Korean, French, Russian and Chinese technologies provide a lower capital cost option compared to the AP1000. For the U.S., given strict labor laws and tough export control rules, Westinghouse currently is the main advertiser of large reactors. However, as of this report's writing, KHNP has started more serious discussions with U.S. utilities given there is now a serious market for large reactors and the APR1400 is already certified by the NRC.

Given the near-term urgency of deploying nuclear reactors to meet the particular growth in the U.S. south east market due to a rise in manufacturing, data centers and migration, only reactors with advanced licensing interactions with the NRC can be considered in Table 2. Microreactors are excluded from this list as they are primarily being developed for niche applications and the list focuses on the main electric grid. Given the uncertainty in the fuel supply and recent economic projection of these reactors, BWRX 300 is selected as a representative SMR with near term promise from the list. **Other promising technologies such as Natrium and microreactors will be the focus of an upcoming report.**

BWRX300 is currently being actively designed for deployment by Ontario Power Generation (OPG) for commercial operation in 2029.[25] The license to construct is expected to be granted to OPG by the Canadian regulator in 2024. Assuming one year of commissioning, the BWRX300 is predicted

[23] https://www.powermag.com/potential-deal-brewing-for-second-polish-nuclear-plant-based-on-south-korean-technology/
[24] https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/3017403
[25] https://www.opg.com/news/darlington-new-nuclear-project-newsletter-winter-2022/

to have a construction schedule of 3 years by the project participants. An independent bottom-up study of an architecture similar to BWRX300 by MIT raises doubt in this prediction. The FOAK construction schedule from first nuclear concrete to beginning of plant commissioning activities was predicted to be over 5 years.[26] This is consistent with the construction schedule of a smaller FOAK 100 MWe PWR SMR (ACP-100 by CNNC) in China (est. 58 month).[27] CNNC has also estimated the cost of ACP-100 to be 2x their large reactors on per kw basis.[28] The existing CANDU refurbishments has also taken more than 5 years to complete (closer to 10 years).[29]

Table 2. List of small reactors with reasonable NRC interaction to achieve license this decade (Blue water cooled and orange non-water cooled).

Reactor Vendor	**Concept**	**Power Rating**	**Fuel/Maturity/Engagement**
NuScale Power	VOYGR	77 MWe module	LEU/High/Certified
GE-Hitachi	BWRX300	300 MWe	LEU/High/Medium
Holtec Int.	SMR300	300 MWe	LEU/Med/Low
Westinghouse	AP300	300 MWe	LEU/Med-High/Low
TerraPower	Natrium	420 MWe	HALEU/Med/Low-Med
X-Energy	Xe-100	80 MWe Module	HALEU/Med/Low
Kairos	Hermes	<100 MWe	HALEU/Low/Medium
Oklo	Aurora	<50 MWe	HALEU/Med/Low-Med

Top-Down approach: On cost, the final design diagram that is available shows a reactor building that is in similar diameter and height as the 1350 MWe ABWR. The cost estimate for ABWR in the south Texas project in 2010 of $3,700/kW for 2x ABWR is estimated to be $5,550/kW in 2024 dollars. Assuming the ABWRs would undergo similar cost escalation as Vogtle as supported by the 40% increase in estimate around 2010s, a factor of 2x would have realized $11,000/kW. This would provide a lower limit for 2 BWRX-300s. Utilizing a power scaling exponent of 0.5 which is between nuclear island typical scaling of 0.6 and turbine island scaling of 0.4, a 2x multiplier is applied. This is reasonable

[26] https://doi.org/10.1016/j.nucengdes.2023.112305
[27] https://world-nuclear-news.org/Articles/Core-module-completed-for-Chinese-SMR#:~:text=First%20concrete%20for%20the%20ACP100,completed%20in%20March%20this%20year.
[28] https://nucleus.iaea.org/sites/INPRO/df17/IV.1.-DanrongSong-ACP100.pdf
[29] https://www.ans.org/news/article-5203/darlington3-refurbishment-completed-ahead-of-schedule/

given the 4.5 times higher power rating for ABWR with a reactor building similar size as the BWRX300. Assuming fully modularized civil and equipment construction that would realize a 15% learning rate for 9x BWR can reduce the 9^{th} BWRx300 by 1.5x. This would mean on average, 9x BWR would come at a cost of 2x ABWR cost / 1.5x/2 = $17,600/kW in 2024 for FOAK. Since only 8x BWRX300 are needed to match 2x AP1000 cost, then same value is used for fleet of 8x BWR for consistency with later comparisons.

Bottom-Up Approach: the bottom-up approach depends on the specific architecture and assumption following the NCET methodology.[15] Escalating previous work FOAK estimate to 2024, the latest BWRX300 architecture from OPG's construction license application and the best estimate 80-month FOAK construction schedule, $14,000/kW is estimated as FOAK overnight cost without any owner's cost. For comparison, the previous architectures as reported publicly by GEH are modeled showing the evolution of design complexity and cost. Almost all paper reactor designs typically undergo similar evolution in cost escalation including the early AP1000 cost estimates provided by Westinghouse. In the bottom-up approach, only learning for each set of 2 plants is applied as it is assumed learning among the 2 units is minimal as schedule and labor work is done in parallel. Therefore, there are only two opportunities for learning rate (learning by doubling) but the FOAK pitfalls are assumed to impact the 8^{th} unit, since the preparation for construction of the 8^{th} unit is started in parallel to the first unit in order for the total project schedule to match the schedule of 2x AP1000. However, a more economical approach that minimizes cost overrun is the construction of the 1^{st} BWRX300 followed by 8 consecutive installations (similarly in Darlington, after completion of the first reactor, the plan is to add 3 additional reactors). The cost estimate is provided for each path way:

SMR Scenario 1: build 8 parallel BWRX300s: cumulative learning of 1.3x is applied for the 8^{th} unit, resulting in a cost of $12,200/kW without Owner's cost for a fleet of 8x BWRX300. Applying a similar methodology as in the previous report on Owner's cost, the FOAK overnight cost of $16,700/kW is realized.

SMR Scenario 2: Complete 1 BWRX300 followed by additional 8 BWRX300 in parallel: cumulative learning of 1.3x is applied again for the 8^{th} unit from the 2^{nd} unit, but the 1^{st} unit starts with 1.8x learning by assuming the same FOAK to 2^{nd} of a kind learning from AP1000. This results in $7,600/kW for 9^{th} BWRX300 which is 1.6x lower than the $12,200/kW, however the total construction time is now 2 times the 2x AP1000. Adding Owner's cost, arrives at $9,500/kW for scenario 2.

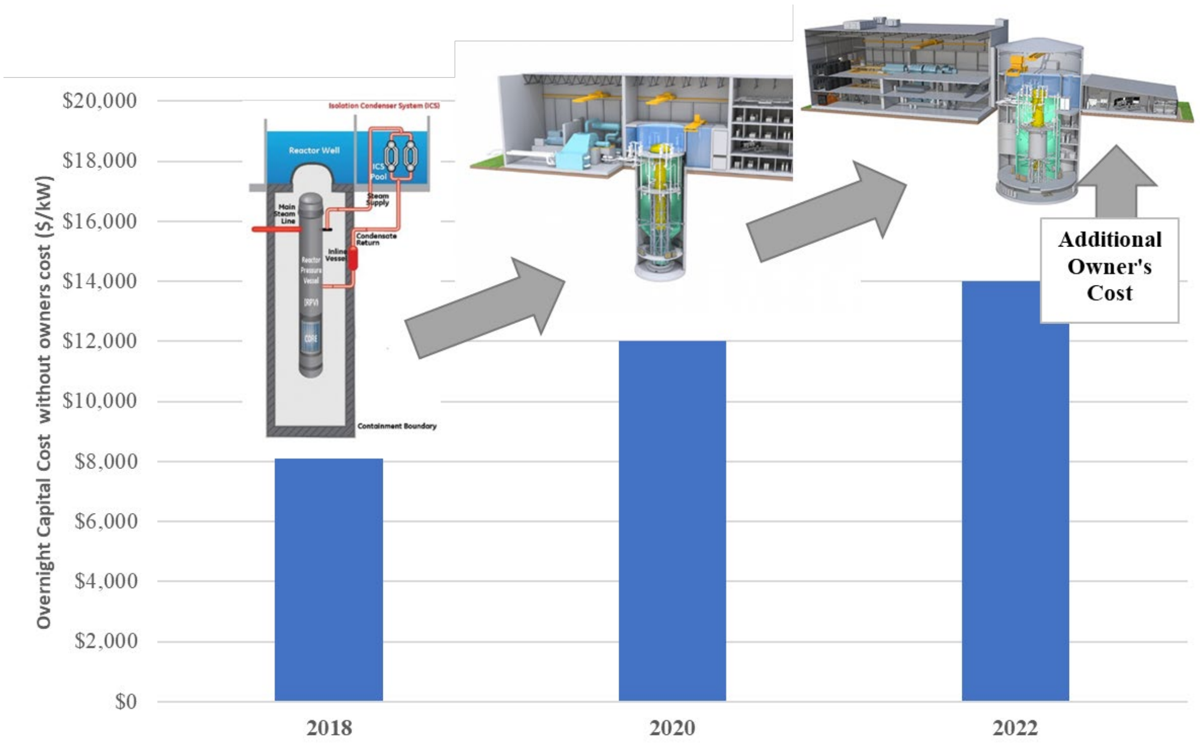


Figure 1. Overnight Capital cost of FOAK BWRX300 without Owner's cost (Source of Images from Left to right: Image 1, Image 2, Image 3)

Under scenario 1, the Top-down and Bottom-up approach, remarkably result in a similar range of \$16,600/kW to \$17,600/kW of overnight cost for a fleet of 8 BWRX300s constructed on a single site in 2024 dollars. The median number is taken at \$17,000/kW as baseline for scenario 1 analysis.

Based on the previous report, the O&M cost of \$28.2/MWhre for a 4-unit 300 MWe is estimated for 90% capacity factor. This number is further verified by the more recent sophisticated and validated bottom up O&M modeling done by Candido & Shirvan, 2023 (ANS). This is a reasonable number for 8x-BWRX300 as servicing 4 reactors is assumed to be the maximum a single worker can manage based on empirical data obtained from existing fleet practices worldwide. This is directly applicable for Scenario 1, but for Scenario 2, while the 2nd batch of BWRX300 are being constructed, the single unit plant will experience O&M of \$38.7/MWhre (at 90% capacity factor).

The same fuel cost as an AP1000 is assumed for the BWRX300 at \$9 MWhre as core leakage in the BWRX300 is only slightly higher than AP1000 and similar target discharge burnup is assumed.

An additional capital cost \$10/MWhre is assumed after a 30-year period for refurbishment and life extensions, scaled by the total bottom up estimate of the O&M cost.

Similar financing parameters as the AP1000 is assumed given the total project size is similar but with 85% capacity factor instead 93% to reflect the novelty of the design in the first 20 years, also in line with new Japanese BWRs. Capacity factor is then increased to 93% after 20 years. No power uprate is assumed given the limitation of natural circulation.

Scenario 1 LCOE:

The levelized cost of capital is estimated to be \$234/MWhre and \$145/MWhre without and with ITC/LPO is estimated for 8 BWRX300. The average lifetime LCOE over 80 years is calculated to be \$237/MWhre and \$167/MWhre which are 1.7 to 1.75x higher than the average of next AP1000 in Table 1. Therefore, given both the cost and absolute magnitude of investment (>\$40 billion), >150 month schedule, building 8x BWRX300 makes little economic sense compared to pair of AP1000s and this scenario is not considered further.

Scenario 2 LCOE:

The FOAK is projected to realize a lifetime LCOE of \$194/MWhre with ITC/LPO. The 2nd set of construction would fall beyond the IRA which expires in 2035. But the learning would push down the \$135-\$123/MWhre for 4 to 12 pack construction. This scenario will result in LCOE similar or 1.3x the next AP1000. This is a better value proposition but pushes the schedule of having equivalent nuclear energy on the grid from early 2030s to late 2030s. However, in this route only \$6 billion is initially required to be financed followed by average of \$19 billion for the additional 8 BWRX300s vs. about \$20 to \$30 billion initial cost needing for financing 2 AP1000s. Since Scenario 2 (similar to OPG's plan) gives much improved economics, it is used for direct comparison with the AP1000.

Comparing 23 GWe AP1000 vs. 7 GWe and 23 GWe of SMR deployment:

As shown in Figure 2, the AP1000 route still holds more merit than the SMR route, as long as the large \$20-\$30 billion amount of capital can be obtained from a group of utility owners. Figure 2(left), shows that on overnight basis, the SMR realizes higher \$/kW but achieves higher cost reduction due to its greater degree of modularity and smaller total onsite labor hours. However, this increase in reduction cannot overcome lack of economy-of-scale on overnight basis at NOAK. Figure 1 shows several interesting trends:

1. While ITC is helpful for AP1000, it does not leave a margin for contingency even on lifetime basis for the next 8 offerings which motivates additional subsidy to achieve NOAK economics and not raise electricity generation rates for customers

2. SMR FOAK will come online at the same time as the next 2 AP1000s. This means AP1000s would have had 4 commercial projects, after which its cost and schedule certainty are significantly higher than

SMRs. The cost advantage is mainly from the fact that it already realized in FOAK.

3. By 2060 20x AP1000s could be reasonably deployed by a consortium of utilities in a region resulting in at least 23 GWe of new nuclear energy without consideration of power uprates. At the same time, for the same timeline and similar number of reactors would result only 7.2 GWe for the SMR.

4. 7 GWe phased deployment of the SMR by 2060 provides significant reduction in financed capital and potential cost escalation risk to the utility, its shareholders and rate payers compared to AP1000. Also, there are other factors that an owner may go with SMR such as eligibility to subsidy (such as the case in U.S. and Canada's SMR focused programs) as well as lack of need for 1000 MWe.

5. The LCOE for the SMR case ends up 45% higher than AP1000, driven by higher O&M cost.

6. In order to demonstrate the impracticality of matching large reactor output with SMRs, Figure 2 shows the investment cost needed for SMRs and AP1000 for the same capacity. It is a fallacy to assume SMRs will reduce investment cost unless also assuming adding proportionally less nuclear to the grid, which may be the only way a sole utility could build new nuclear.

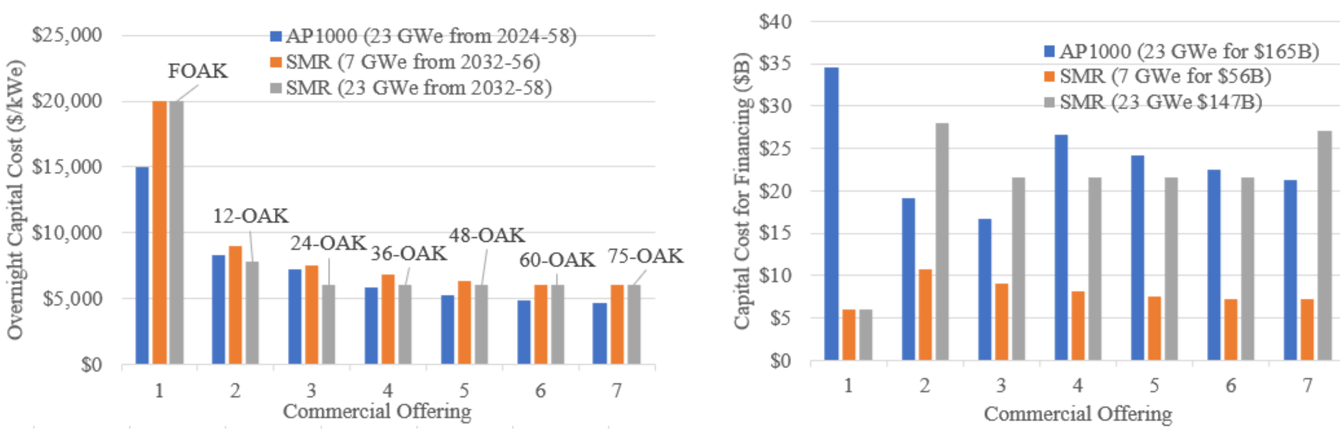
The major drawback of the AP1000 or the SMR is their high LCOE during the 30-year financing period. As such, there are currently no firm announcements to build new nuclear power plants as such high LCOE for less than half of the plant life is viewed negatively by a majority of electric utilities in the U.S. and their public commissions. However, there are two fundamental flaws with this position that electric utilities and their shareholders need to comprehend:

1. Decarbonization cannot take place in near term while maintaining existing electricity generation LCOE. As shown in Table 1, even with the limited firming cost added to other electricity generation sources (PV, CCNG), their cost is significantly higher than the current price of electricity generation in almost all U.S. markets. In addition, specifically for renewable energy sources, each added capacity of intermittent generation will make the additional capacity less valuable and increase the total generation cost as shown by several studies.[30]

2. Renewable technology has benefited from sustained subsidy over the course of more than 20 years in the U.S. and has attained NOAK economics (see Table 2). The IRA provides similar subsidies to FOAK nuclear and NOAK renewables and the expectation that FOAK SMR will have as excellent an operating track record as existing large reactors is unrealistic. As shown by Table 1, AP1000 at its NOAK cost ($66/MWhre) can actually maintain the average electricity generation cost at the current national average. Therefore, it is clear that to achieve decarbonization at an affordable price, the government needs to provide the same subsidy that it provided for renewables prior to IRA until AP1000 reaches its NOAK and can stand on its own vs. other firm carbon-free sources even during its financing period. In the case of the 300 MWe SMR, the subsidy can allow

[30] https://doi.org/10.1016/j.joule.2018.08.006

the SMR to reach NOAK LCOE that would be competitive with other firm carbon-free generation in certain markets. The high penetration of SMR will not only raise the average cost of electricity, but also does not result in a reduction in total investment, the labor force needed for construction and operation compared to the AP1000. In the end, NOAK large and small reactors will be built on similar schedules which is on the order to 4-5 years not 6-month that many renewable and battery storage projects are experiencing. As such the lower capital cost of SMRs can only be taken advantage of at lower capacity additions, which will both delay the carbon transition and not fully realize the opportunity to replace the massive generation of coal and CCNG that will retire in the next few decades while meeting the growing demand of data center and chip manufacturing.



AP1000 (23 GWe from 2024-58)			SMR (7 GWe from 2032-56)			SMR (23 GWe from 2032-56)		
Year (Finished)	Offering	Lifetime LCOE	Year (Finished)	Offering	Lifetime LCOE	Year (Finished)	Offering	Lifetime LCOE
2024	FOAK	$154	2032	FOAK	$194	2032	FOAK	$194
2031	Next 2	$127	2037	4-OAK	$136	2037	12-OAK	$123
2037	4-OAK	$96	2042	8-OAK	$113	2042	24-OAK	$95
2043	8-OAK	$83	2046	12-OAK	$104	2046	36-OAK	$95
2048	12-OAK	$74	2050	16-OAK	$109	2050	48-OAK	$95
2053	16-OAK	$68	2053	20-OAK	$95	2054	60-OAK	$95
2058	20-OAK	$66	2056	24-OAK	$95	2058	75-OAK	$95

Figure 2. Overnight Capital Cost (left) and total investment cost (right) comparison of AP1000 vs. two SMR scenario by Late 2050s. First SMR scenario has similar number of plants as AP1000 (Motivation behind SMR is to lower the total financing cost), second scenario provides the same capacity as AP1000; The commercial offerings are evenly distributed based on a construction schedule according to the Table (Bottom). Year (finished) refers to start of commercial operation. IRA subsidy expires by 2035, however it is assumed the LPO support is continued for the first plants who entered commercial operation after 2035 but discontinued there after (e.g., all numbers past 2040 are unsubsidized). FOAK AP1000 refers to Vogtle3&4, Next 2 are average of the values in Table 1.

In closing, deep decarbonization while maintaining current cost of generation can only be realized with NOAK nuclear. Large NOAK water-cooled nuclear has about 1.45x advantage in LCOE over small NOAK water-cooled nuclear. Though, small NOAK maybe preferred due to other factors such as lack of demand for 1000+ MWe and ineligibility of large water-cooled reactor to apply to certain subsidies (such the case in U.S. and Canada). **Based on the quantitative analysis in this report, U.S. government (federal or state) must provide \$25 billion through ITC/PTC over course of 20 years (\$1.25 Billion per year) for each nuclear technology to facilitate their ability to reach NOAK costs.**

V. Impact of AP1000 on U.S. National Security

In the U.S., there are several projects focused on the deployment of non-water-cooled reactors including the Xe-100 by X-Energy and Natrium by Terrapower for commercial application and Pele by BWXT for military application (U.S. Army) that utilize High-Assay Low-Enriched Uranium (HALEU), 5 to 20% enriched fuel. In a recent U.S. Congressional hearing on international financing for nuclear energy on Jan 17, 2024, members of the U.S. Congress, incorrectly influenced by NGOs and think tanks in attendance alluded that Russia and China are exporting non-large water-cooled reactor technology, which would motivate the U.S. government to act in support of non-water-cooled technologies to remain competitive with Russia and China. Consequently, the majority of the grants that the U.S. government is investing in for nuclear energy is going toward non-water cooled reactors: \$3.2 billion for Tier-1 Advanced Reactor Demonstration Program and \$800 million plus part of the recently passed \$2 billion on HALEU. Meanwhile 20% of US electricity and 100% of its nuclear energy generation is from large LWRs, while a similar picture is found internationally including in Russia and China, as noted in section I, as they only export water technology. One reason the U.S. has not provided grants for large water-cooled reactors is likely that it is treated as a legacy technology and not attractive for NGOs to advocate for and should be commercialized on its own merit. As the Vogtle project in U.S., the Flamanville project in France, and the Hinkley point project in the UK have shown, restarting nuclear construction under new modern regulation experiences FOAK pitfalls. The FOAK cost overrun for wind turbine, solar thermal, solar PV and more recently battery storage were all covered with subsidies as partially shown in Table 2. The fundamental difference is that each unit of nuclear involves billions of dollars in investment but same learning law still applies to a nuclear power plant (albeit at a different learning rate). Without such subsidies it is hard to ask any energy source to compete with other subsidized sources.

Table 2. Levelized expenditure subsidy for renewable energy.[31]

Levelized Subsidy ($/MWhre)	***2010***	***2013***	***2016***	***2019***
Solar	***880***	***670***	***100***	***70***
Wind	***57***	***34***	***13***	***15***

It should be noted that nuclear technologies like microreactors will have different needs and subject to a different support structure given their potential to be rapidly deployed under supportive regulatory environment. Therefore, the discussion in this report is not applicable to microreactors and this is focus of a future report based on ongoing work at MIT. Given the realities of funding appropriations, the following support is recommended that can help the U.S. regain its leadership in nuclear energy:

1. Low interest loan guarantees: Specific to nuclear as the construction schedule is multi-year.

2. Cost overrun insurance: Specific to nuclear as even SMRs are mega-projects and any schedule slippage can result in a loss of millions of dollars.

3. Providing both ITC and PTC from IRA till 10^{th}-AOK has been reached: Subsidy has shown to be fundamental for other sources of clean energy to realize penetration. Until the learning rate is not realized, it is hard to imagine a commercial product can be realized with the FOAK demonstration.

4. At the end, the process of exporting reactor technology is not a profitable business. Rather, the fuel and services that follow can provide long lasting relationship with the host country. Expanding U.S. control over the fuel cycle and maintaining healthy industry will support nuclear vendor business deals on this front in the international market.

With these programs, U.S.-born nuclear technology can then be exported effectively and can compete on the international level with our adversaries.

[31] https://www.forbes.com/sites/jamesconca/2017/05/30/why-do-federal-subsidies-make-renewable-energy-so-costly/?sh=2bc12aaf128c