David Schlissel, Director of Resource Planning Analysis
Dennis Wamsted, Energy Analyst
February 2022

Institute for Energy Economics and Financial Analysis
IEEFA.org

NuScale's Small Modular Reactor

Risks of Rising Costs, Likely Delays, and Increasing Competition Cast Doubt on Long-Running Development Effort

Executive Summary

Too late, too expensive, too risky and too uncertain. That, in a nutshell, describes NuScale's planned small modular reactor (SMR) project, which has been in development since 2000[1] and will not begin commercial operations before 2029, if ever.

As originally sketched out, the SMR was designed to include 12 independent power modules, using common control, cooling and other equipment in a bid to lower costs. But that sketch clearly was only done in pencil, as it has changed repeatedly during the development process, with uncertain implications for the units' cost, performance and reliability.

For example, the NuScale power modules were initially based on a design capable of generating 35 megawatts (MW), which grew first to 40MW and then to 45MW. When the company submitted its design application to the Nuclear Regulatory Commission in 2016, the modules' size was listed at 50MW. Subsequent revisions have pushed the output to 60MW, before settling at the current 77MW. Similarly, the 12-unit grouping has recently been amended, with the company now saying it will develop a 6-module plant with 462MW of power. NuScale projects that the first module, once forecast for 2016, will come online in 2029 with all six modules online by 2030.

While these basic parameters have changed, the company has insisted its costs are firm, and that the project will be economic.

Based on the track record so far and past trends in nuclear power development, this is highly unlikely. The power from the project will almost certainly cost more than NuScale estimates, making its already tenuous economic claims even less credible.

Worse, at least for NuScale, the electricity system is changing rapidly. Significant amounts of new wind, solar and energy storage have been added to the grid in the past decade, and massive amounts of additional renewable capacity and storage will come online by 2030. This new capacity is going to put significant downward pressure on prices, undercutting the need for expensive round-the-clock power. In addition, new techniques for operating these renewable and storage resources, coupled with energy efficiency, load management and broad efforts to better

[1] NuScale. Frequently Asked Questions; Corporate Commitment.

integrate the western grid, seriously undermine NuScale's claims that its untested reactor technology will be needed for reliability reasons.

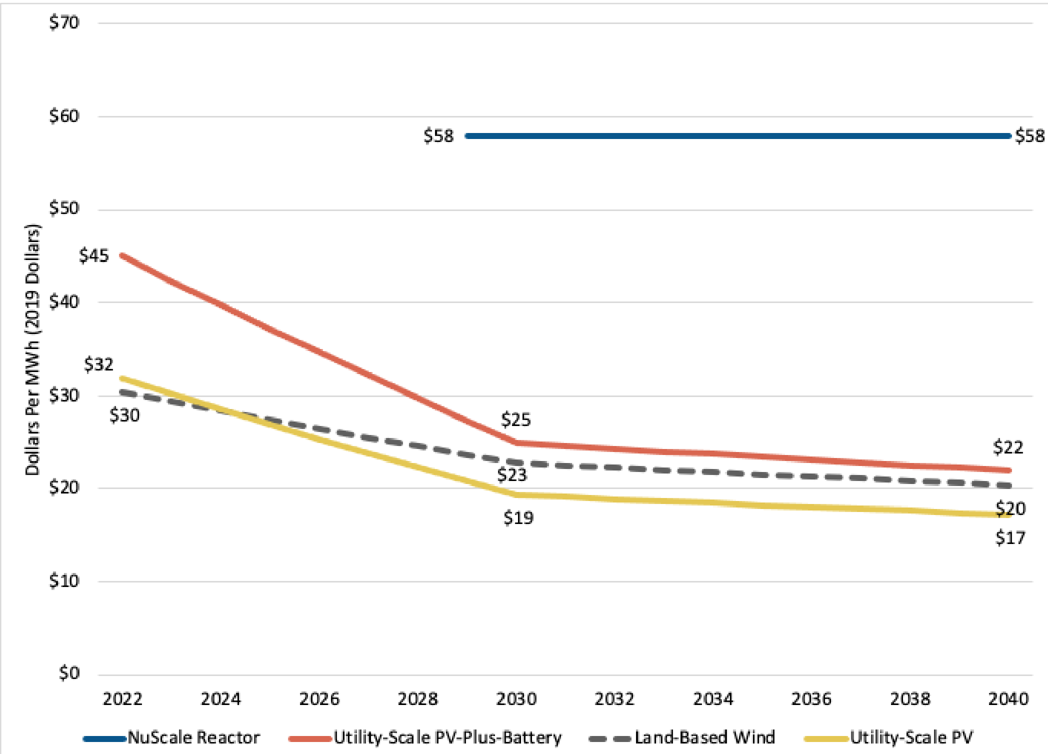
This first-of-a-kind reactor poses serious financial risks for members of the Utah Associated Municipal Power System (UAMPS), currently the lead buyer, and other municipalities and utilities that sign up for a share of the project's power. NuScale is marketing the project with unlikely predictions regarding its final power costs, the amount of time it will take to construct and its performance after entering commercial services:

- There is significant likelihood that the project will take far longer to build than currently estimated;
- There is significant likelihood that its final cost of power will be much higher than the current $58 per megawatt-hour claim;
- There is significant likelihood that the reactor will not operate with a 95% capacity factor when it enters commercial service.

As currently structured, those project risks will be borne by the buying entities (participants), not NuScale or Fluor, its lead investor. In other words, potential participants need to understand that they would be responsible for footing the bill for construction delays and cost overruns, as well as being bound by the terms of an expensive, decades-long power purchase contract.

These compelling risks, coupled with the availability of cheaper and readily available renewable and storage resources, further weaken the rationale for the NuScale SMR.

Figure: NuScale's Estimated Target Price of Power from Its Proposed Reactor Is Much Higher Than the Projected Cost of Power From Renewable Alternatives



Sources: UAMPS Presentation to Los Alamos County, page 4. July 21, 2021; National Renewable Energy Laboratory, 2021 Annual Technology Baseline: Utility-Scale PV-Plus-Battery.

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Introduction

Oregon-based NuScale has been working since 2000 to commercialize a smaller scale version of the conventional pressurized water reactors that account for two-thirds of the existing fleet of operating nuclear power units in the U.S. It is one of several companies in the U.S. looking to market variations of existing reactor technologies as potential solutions for future power needs in a carbon-constrained environment. In this analysis, IEEFA has chosen to focus on the small nuclear reactor (SMR) that NuScale is building for the Utah Associated Municipal Power Systems (UAMPS) since its development efforts are currently the most advanced—even though the company's first unit is now expected not to begin generating power until 2029. Still, while focused on NuScale, the technology and implementation concerns and the financial questions we raise in the following pages also apply to the other competitors looking to enter the SMR market.[2]

The advent of new SMR projects represents the most serious recent push for new nuclear power in the U.S. after a spate of announced reactor plans in the 2000s foundered due to high costs and massive construction delays. NuScale and the other SMR entrants contend that this time will be different. In its marketing, for example, NuScale touts its SMR option as "one that is smarter, cleaner, safer and cost competitive."[3]

These promises have been made and broken repeatedly throughout the history of the nuclear power industry.

In the following pages, we dive into the serious commercialization and operational risks that are likely to boost the final cost of electricity from NuScale's proposed SMR.

In addition, we highlight the major contract-related risks faced by members of UAMPS, the current lead backer of the NuScale development effort, and other participating municipalities and utilities. As currently structured, if the project proceeds to construction, the economic risks rest almost entirely with the power buyers rather than NuScale and Fluor, its largest investor.

Finally, we detail the major changes sweeping across the U.S. electricity grid, particularly in the Western Interconnection where the NuScale project is to be built. The vast buildout of new renewables and battery storage that will occur by 2030—the intended date for the NuScale project to enter full commercial operation—is going to restructure the western grid. Power prices will remain constrained, challenging the economics of the NuScale plant; new operational tools will enable renewables and storage to provide an expanded suite of grid reliability services, undercutting NuScale's claims that nuclear is needed for grid firming; and broader integration of the entire Western Interconnection is going to provide utilities across

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[2] SMRs are defined by the International Atomic Energy Agency as plants that produce up to 300 megawatts of electricity per module.
[3] NuScale. Technology Overview; How the NuScale Module Works.

the region with increased access to less expensive supplies of power, including excess solar from California and the Desert Southwest.

Risk 1: NuScale's SMR Is a First-of-a-Kind Design That Has Not Been Built, Operated or Tested at Commercial Scale

The NuScale small modular reactor project is a first-of-a-kind design (FOAK), untested and unproven at commercial scale.

Despite these uncertainties, NuScale claims the construction cost of its reactor will be below $3,000 per kilowatt (kW), an extremely low cost that no new reactor has achieved for decades; that it will be built in 42 to 54 months, far less time than any new reactor has achieved for decades; and that once built, it will run at a 95% capacity factor[4] over its entire operating lifetime, which would be better than any of the 93 reactors currently operating in the U.S. have done. But these claims about the project's future cost and performance are pure speculation as there is no actual construction or operating track record with the NuScale SMR design, or long-term full-scale test results, to support them. Thus, there is no reason to believe proponents' claims about how much it will cost to build and operate, how long it will take to build, and how well it will operate over its proposed service life.

In fact, the optimism in NuScale's marketing is misleading because they can't really say what the new SMR's features will do because none have been built and operated.

> *With our scalable design, the first module* ***immediately generates*** *power and revenue while additional modules are being planned or installed. NuScale* ***has*** *a shorter nuclear construction period of less than 36 months from the first safety concrete through mechanical completion. NuScale plants* ***have*** *a high capacity factor and* ***consistent*** *operation costs,* ***reducing*** *the volatility of electricity production costs as compared to energy sources that rely on the weather or have volatile fuel prices.*[5] [emphasis added]

New nuclear and non-nuclear projects with first-of-a-kind designs typically experience unanticipated schedule delays, cost increases, and problems during both construction and the initial periods of operations, if not longer. These problems lead to lower-than-projected operating performance and higher-than-forecast operating costs. There is no reason to expect that the NuScale SMR will be any different.

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[4] A power plant's capacity factor measures how much energy (in megawatt hours) it produces in a month or a year compared to how much it would have generated if it had operated at full power for every hour in the month or year. The higher the capacity factor, the better.
[5] NuScale. NuScale SMR Technology: An Ideal Solution for Repurposing U.S. Coal Plant Infrastructure and Revitalizing Communities, page 4. 2021.

Risk 2: The Construction Cost of the New SMR Will Be Significantly Higher Than NuScale Claims

The company's cost estimates for its small modular reactor have been remarkably low for a new, as-yet-unbuilt technology.

In 2016, the company's chief commercial officer, Mike McGough, said NuScale's SMR could be built for $5,078/kilowatt (in 2014 dollars).[6] By the end of 2020, with the expected first operational plant still 10 years in the future, NuScale had lowered its projected "overnight" construction cost estimate to $2,850/kW.[7] An overnight cost estimate does not include escalation or financing costs.

There are a number of compelling reasons to doubt NuScale's latest, and lowest, construction cost estimate.

First, NuScale and UAMPS have a vested interest in promoting a low-cost estimate in order to encourage new participants to sign up for shares of the project.

Second, NuScale's current construction cost estimate has been defined as a Class 4 Project Cost Estimate (PCE) pursuant to guidelines issued by the Association for the Advancement of Cost Engineering (AACE). According to the AACE's February 2006, Recommended Practice No. 18R-97, Cost Estimate Classification System, Class 4 estimates "are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval."[8]

According to AACE, the range for Class 4 estimates can understate actual costs by as much as 50%. In other words, it is not an estimate that should be used in calculating future power costs or contract requirements—but that is exactly what NuScale and UAMPS are doing. Utilities considering signing onto the development effort need to understand just how uncertain the current cost estimate are, since they will be the ones paying for any cost overruns.

It is also important to note that AACE says "unusual circumstances" could render the estimates even less accurate.[9] Considering the technological complexity of the proposed NuScale reactor project and the fact that it involves first-of-a-kind technology, it is reasonable to expect that the actual construction cost could easily be far more than 50% higher than NuScale's current estimate.

A recent submission to the U.S. Nuclear Regulatory Commission (NRC) from NuScale on behalf of the Carbon Free Power Project (CFPP, the official name of the company's SMR for UAMPS) highlights the uncertainty surrounding how much it actually will cost to build the new SMR. In their submission, NuScale responds to a

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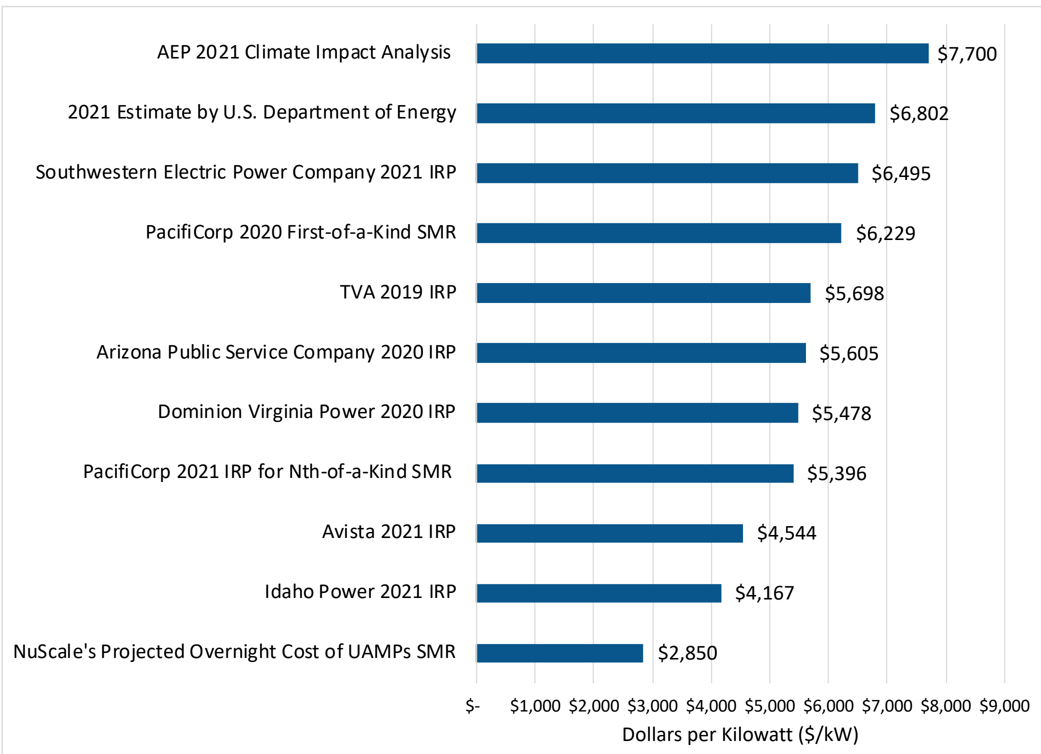
[6] NuScale. NuScale Power Announces an Additional 25 Percent in Nuclear Power Module Output. November 10, 2020.
[7] NuScale. 2020 In Review.
[8] AACE International. Recommended Practice No. 18R-97, page 4. February 2005.
[9] *Ibid*.

question about the current status of the development of the facility design by specifying that the "Facility design is considered to be preliminary."[10] NuScale also informed the commission that the final facility design documentation would be readied when required in support of the SMR's Combined Operating License Application, which will not be filed until January 2024.[11]

In contrast to NuScale's low construction cost estimates, entities without vested interests in the technology's commercialization expect the development costs to be much higher than NuScale's current $2,850/kW estimate, raising fundamental questions about the credibility of NuScale's promotional figures. Some of these estimates are shown in Figure 1 below.

Figure 1: SMR Overnight Cost Estimates



Sources: World Nuclear News and Utility Integrated Resource Plans and Climate Impact Analyses.

There are two SMR overnight construction cost estimates by PacifiCorp in Figure 1. The first, from a presentation in September 2020, was for a First-of-a-Kind NuScale SMR, which is effectively the UAMPS SMR. The second, from PacifiCorp's 2021 IRP, was for an Nth-of-a-Kind reactor. The term Nth-of-a-Kind refers to the fact that the reactor would not be built for years until an unspecified number of other NuScale reactors had already been completed. The expectation is that the cost of building and operating NuScale reactors would decline over time because of an assumed

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[10] NuScale. Attachment to Carbon Free Power Project submission to the U.S. Nuclear Regulatory Commission in Docket No. 99902052, page 3. January 28, 2022.
[11] *Ibid.*

learning curve and economies-of-scale. While this is widely assumed in the nuclear industry, it has only rarely been achieved.

In addition, NuScale's current $2,850/kW overnight cost estimate was predicated on a project with 12 reactor modules. Given that NuScale/UAMPS have officially downsized the project to just six modules, it is reasonable to expect that the construction cost per kilowatt will rise as a result given that the cost of the project's common equipment now will be split six ways instead of 12.

In fact, NuScale and UAMPS have acknowledged that the estimated costs of building and operating the SMR will not decrease proportionally because the number of modules has been reduced from 12 to six modules.[12] For example, UAMPS suggested that the following talking points be used when discussing the downsizing of the project to just six modules:

- The nuclear island, i.e., reactor, control and radwaste building size and cost is not reduced by 25% for a reduction in plant size from 8 to 6 modules.
- Shared systems and equipment (e.g., reactor building crane, reactor vessel assembly/disassembly) remain the same regardless of the number of modules.
- Certain non-EPC (engineering, procurement, and construction) costs, referred to as "Owner's Costs," do not reduce proportionally when the number of modules is reduced. For example, the cost to develop the NRC Combined License Application (COLA) and subsequent NRC review of the COLA and issuance of a Combined License is generally the same regardless of plant size.[13]

Thus, the per kW cost of the proposed reactor project after the downsizing from 12 to six modules is certainly higher than the $2,850 per kW cost publicly claimed by NuScale. No new estimates of the plant's construction cost have been released by NuScale or UAMPS since announcing the scaling back to six modules instead of the original 12. Instead, we have only seen the talking points discussed above that discuss the impact of decreasing the SMR from eight modules to six. Therefore, it is unclear whether NuScale's currently estimated overnight construction cost is for the six-module project although we suspect it will likely be higher than $3,000 per kW but still far below SMR construction cost estimates by other parties.

Finally, the history of the nuclear industry strongly suggests that the actual construction cost of the NuScale SMR will be much higher than the current Class 4 estimate. For example, a DOE study of 75 reactors whose construction began in the years 1966-1977 found that the average overnight cost of construction for these

[12] UAMPS. Official Notice of the Revised Budget and Plan of Finance for a Six NuScale Power Module Facility Configuration, pages 7-8. June 24, 2021.
[13] *Ibid*.

reactors was 207% higher than the estimated cost.[14] In other words, on average, the cost of construction tripled while the plants were being built.

The costs of new first-of-a-kind reactors recently under construction also have increased dramatically while being built.[15]

- The projected construction cost of the Vogtle 3 and 4 Project in Georgia (which has a new AP1000 design) has grown 140% from an original $9.1 billion, not including financing costs, to over $19 billion – and this does not include another $1 billion that the staff of the Georgia Public Service Commission projects will have to be spent to finish the two new reactors.[16] As the project still has at least one year of construction and testing remaining before both units are in commercial operation, its final construction cost can be expected to grow even higher. Costs have grown so high that the staff of the Georgia Public Service Commission now expects the full cost of electricity from the new Vogtle reactors will average $150 per MWh.[17]

- The original estimated cost of the now-cancelled Summer 2 and 3 project in South Carolina was $5,075/kW (without financing costs). The estimated cost at the time of cancellation in July 2017 had increased by 57% to $7,960/kW. The project was cancelled because the two owners decided it was too expensive to complete even though they had already spent $9 billion.[18]

- The estimated construction cost of the Hinkley Point C European Pressurized Reactor (EPR) project., currently in its fourth year of construction in the United Kingdom, has increased by 22% to 27% (from 18.1 billion UK pounds, without financing costs, in 2018, to £22 to £23 billion in early 2021).[19] As the project still has five years until its planned in-service date, the construction cost is expected to increase further.

- The original estimated cost of Flamanville EPR in France was EUR3.3 billion. By July 2020, the project's estimated cost had jumped to EUR12.4 billion, a whopping 276% increase, and a French Court of Audit has estimated that the cost could exceed EUR19 billion, which would represent an even higher 475% increase. The unit is not yet in commercial operation.[20]

- By 2012, the cost of building the Okiluoto 3 EPR in Finland had increased to at least triple its original EUR3.2 billion estimate. And that construction cost

[14] U.S. Department of Energy, Energy Information Administration. An Analysis of Nuclear Power Plant Construction Costs, Technical Report DOE/EIA-0485. January 1, 1986.
[15] Unfortunately, no costs are available for the first-of-a-kind nuclear plants being built in China.
[16] IEEFA. Southern Company's Troubled Vogtle Nuclear Project. January 2022.
[17] Georgia Public Service Commission. Direct Testimony of Tom Newsome, Philip Hayet, and Lane Kollen, Docket No. 29849. December 1, 2021.
[18] New York Times. U.S. Nuclear Comeback Stalls as Two Reactors are Abandoned. July 31, 2017.
[19] EDF. Hinckley Point C project update (1). January 27, 2021.
[20] Enerdata. Flamanville-3 nuclear project's cost may rise by EUR6.7bn. July 13, 2020.

almost certainly has increased significantly as the project is not yet in commercial operations.

In addition to higher construction costs, these projects also have experienced higher financing costs as their construction schedules have been extended dramatically, as will be discussed below.

Risk 3: The SMR Will Take Substantially Longer to Build Than NuScale Claims

The projected in-service date for NuScale's SMR has already slipped by 15 years—and construction hasn't even begun.

- In January 2008, NuScale told the NRC that an SMR could be producing electricity by 2015-2016.
- In 2010, NuScale said it intended "to submit a design certification application to the NRC early in 2012" and expected "to have its first reactor online in 2018." However, NuScale did not submit its design for NRC review until December 2016.
- In 2018 NuScale announced its plans to commence site preparation in 2021, with "nuclear construction commencing in 2023" as well as its forecast that the first Power Module™ would achieve commercial operation in 2026 and the remaining modules in 2027."
- In July 2020, UAMPS announced that "initial generation" from the first module was delayed until mid-2029, with completion of the remaining eleven modules a year later, in June 2030.

NuScale says that its SMR will have a shorter nuclear construction schedule, less than 36 months between the first placement of safety concrete and mechanical completion.[21]

However, there are several factors which undercut NuScale's claims about being able to achieve such an accelerated construction cost schedule.

First, NuScale makes it appear like the reactor modules would be manufactured at a single location and each finished module would then be transported to the plant site for installation. But this is clearly not the case, as NuScale's answer to a question posed at a July 2020 UAMPS CFPP Town Hall makes clear:

> ***Question****: What is the status of the fabrication plant?*
>
> ***Answer****: The NuScale Power Modules (NPM) design is manufacturer-agnostic because NuScale controls the design and, as a result, can utilize any qualified pressure vessel manufacturer to "build to print" the module. During NuScale*

[21] NuScale, *Op. cit.*, page 5.

> *supply chain development activities, NuScale engaged with approximately 40 qualified and experienced pressure vessel fabricators worldwide and at that time determined that NuScale will utilize existing factories to fabricate the NPM in lieu of building its own factory. The major module subcomponents will be manufactured at multiple manufacturer locations and shipped to a single location for assembly prior to installing into the facility. NuScale is currently contracted with both BWX Technologies and Doosan Heavy Industries and Construction to assist NuScale with its final design for manufacturing. NuScale maintains communications with several other vessel manufacturers for the potential to add future capacity as needed.*[22]

In other words, there will not be a single NuScale factory where the modules for the UAMPS SMR are manufactured and assembled, and there may never be one for subsequent SMR projects. Thus, the fabrication and construction process will be more complicated than NuScale makes it seem.

The recent experience of the Vogtle 3 and 4 units is especially relevant here because, like NuScale, Vogtle was touted as a project that would benefit from modular construction in terms of both shorter construction time and lower costs. In fact, Westinghouse's promotional materials for the AP1000 said the units could be built in just three years because the components would be factory-built and shipped to the site for assembly similar to what NuScale plans for the SMR.

> *The AP1000 has been designed to make use of modern, modular construction techniques… Modularization allows construction tasks that were traditionally performed in sequence to be completed in parallel. Factory-built modules can be installed at the site in a planned construction schedule of three years – from first concrete load to fuel load…*[23]

Those plans did not pan out at Vogtle, and the project is now more than six years behind schedule and vastly over-budget.[24]

Second, NuScale says that its nuclear construction schedule, as measured between first safety concrete through mechanical completion, will be less than 36 months.[25] However, it is silent about when fuel will be loaded and how long it will take to conduct the necessary pre-operational and start-up testing after mechanical completion of the project. Pre-operational and start-up testing can be expected to take six to twelve months, or longer.

Finally, recent nuclear industry experience underscores how unlikely NuScale's claim that it will achieve a nuclear construction schedule of less than 36 months actually is. In fact, as shown in Figure 2, plants with new reactor designs have taken more than twice as long to build as the owners projected at the start of nuclear

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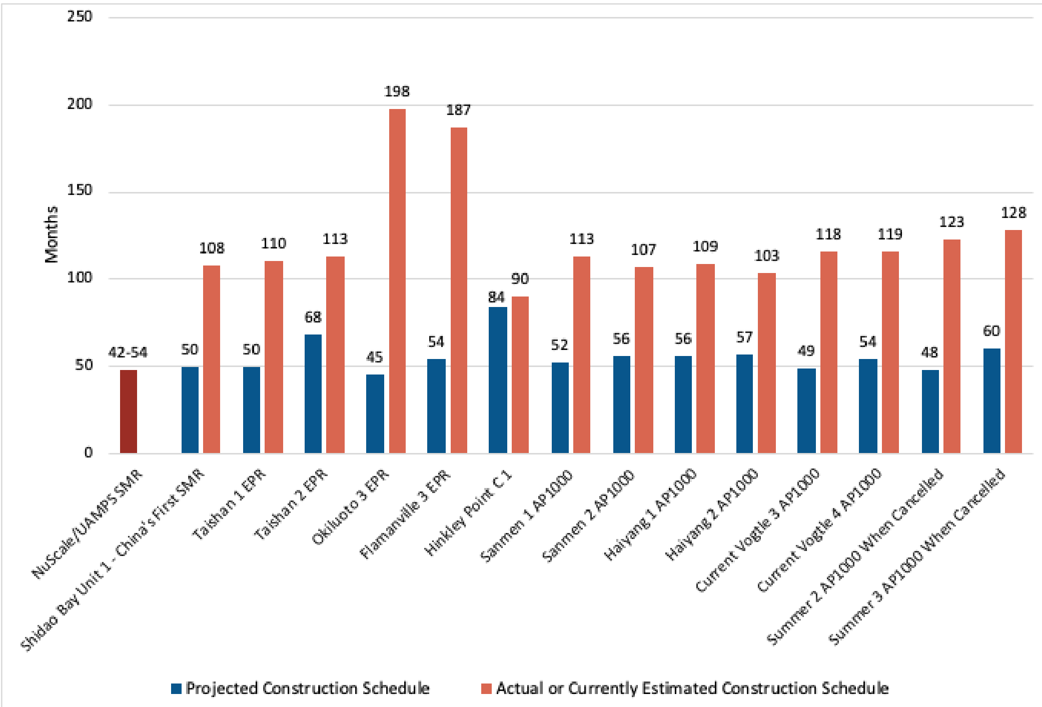
[22] Los Alamos County Department of Public Utilities. NuScale Responses to UAMPS CFPP Town Hall Questions about NuScale SMR Technology. August 6, 2020.
[23] Westinghouse. AP1000 – Ready to Meet Tomorrow's Power Generation Requirements Today, page 15. 2013.
[24] IEEFA, *Op. cit.*
[25] NuScale, *Op. cit.*, page 5.

construction, resulting in delays of four years or longer before the start of commercial operations.

Figure 2: Recent Nuclear Construction Schedules for Nuclear Plants With New Designs[26]



Sources: World Nuclear News and the IAEA Power Reactor Information System (PRIS).

In other words, the reality of recent nuclear projects suggests that NuScale's SMR construction schedule will be considerably longer than the company and UAMPS claim. And Figure 2 only shows the project delays encountered during each plant's nuclear construction phase. Any delays experienced before construction, for example, during the licensing process, are not included. Delays experienced during NuScale's NRC licensing process will push the SMR's in-service date even further into the future.

The construction delays recently experienced by new nuclear reactor projects follow hard on the heels of the industry's earlier problems when, beginning in the mid-1960s, construction of new nuclear power plants began to take significantly longer than initially planned.

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[26] As noted earlier, NuScale projects a nuclear construction schedule of less than 36 months through mechanical completion. We have added an additional six months to this estimate to reflect six months for fuel-load and pre-operational and start-up testing. The result is a low 42-month schedule thru commercial operation for module one of the SMR. Similarly, we have included a 54-month schedule for the remaining five modules because NuScale has said that they would follow one year after the first module goes into service.

For example, the data from the 1986 Department of Energy study discussed earlier shows that 75 new reactors that had started construction in the years 1966 to 1977 had taken an average of 116 months to build or nearly double the 60 months that, on average, had been predicted prior to the start of construction.[27] This study was conservative in that it didn't include a number of units that had experienced substantial schedule delays including South Texas 1 and 2, Comanche Peak 1 and 2, and Vogtle 1 and 2.[28]

Despite this evidence, NuScale is not admitting to potential customers and the public that its project may experience major delays due to one or more of the following factors: the need for significant design changes; to correct serious construction problems; or simply project mismanagement. Issues like this have plagued essentially all reactors built in the U.S. since the mid-1960s. There is no reason to expect that NuScale will be able to avoid them.

Risk 4: NuScale Faces an Impossible Task: Achieving High Capacity Factors and Flexibility

The cost calculations presented by NuScale assume that the new reactor will operate at a high capacity factor over its lifetime. "NuScale estimates that the plant's capacity factor will exceed 95% – making it one of the most reliable electric generation systems available."[29] A high capacity factor (which is simply the ratio of the amount of power a facility generates in a given period, say a year, to the amount of power it could generate if it operated at 100% power for the entire period) spreads the high initial capital cost and fixed operating costs and annual capex (capital expenditures) over the largest amount of production possible, bringing the per unit cost (the all-important $/MWh figure) down as low as possible; in NuScale's newly revised upward estimate, to $58/MWh. Conversely, the lower the capacity factor, the fewer MWh over which the plant's fixed costs can be spread and the higher the $/MWh cost.

NuScale's goal of achieving a 95% capacity factor over the SMR's entire lifetime has never been achieved by any nuclear unit in the U.S.

- The median capacity factor of the 93 reactors still in operation in the U.S. is 83% - a good operating performance but not close to what NuScale claims it will achieve even though there is no actual track record of any reactor design similar to that of the proposed SMR. None of these 93 reactors has achieved the 95% lifetime capacity factor goal that NuScale says its SMR will achieve. Only five of these reactors have lifetime capacity factors above 90%.

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[27] U.S. Department of Energy, *Op. cit.*

[28] According to International Atomic Energy Agency (IAEA) data, construction of South Texas Unit 1 took 152 months, construction of South Texas Unit 2 took 162 months, construction of Vogtle Unit 1 took 130 months and construction of Vogtle Unit 2 took 153 months. IAEA Power Reactor Information System.

[29] NuScale. NuScale Benefits; Diverse Applications.

- The median capacity factor of the 22 commercial-scale reactors in the U.S. that have been retired was 73%. None of these reactors achieved a lifetime capacity factor above 84%.

Typically, what happens with new reactors, especially those with first-of-a-kind designs, is that problems are encountered during start-up testing and initial operations that lead to planned or forced outages or deratings. For example, none of the 93 reactors still operating in the U.S. achieved a 95% capacity factor during their first 10 years of operation; only three had average capacity factors during this initial period operation above 85%, and the median capacity factor of all 93 reactors during these years was just 67% - far below the 95% capacity factor that NuScale suggests it will achieve right from the start with its new SMR. Sometimes, but not always, problems encountered during early years of operation are resolved, lessons are learned and plant performance improves over time. But that is not guaranteed to occur, especially with new and untested plant designs.

Further undermining NuScale's claim that it will achieve a 95% capacity factor with its new SMR design, the company also trumpets the ability of its new reactor to ramp up and down quickly (what is known as load following). The company says this makes it a perfect complement for variable renewable generation. "NuScale's SMR technology includes unique capabilities, allowing it to vary its output as necessary to support system demand as capacity varies from intermittent generation."[30]

The company has touted this flexible operating mode in numerous presentations; including the following graphic NuScale uses to depict the technology's load following ability.

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[30] NuScale, *Op. cit.*

Figure 3: NuScale Illustrative Hourly Load-Following Generation

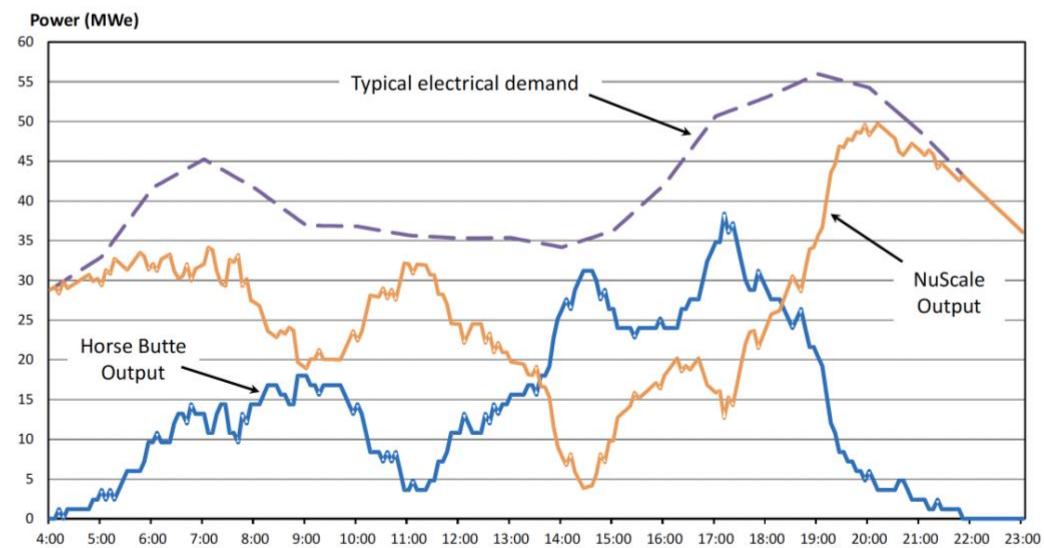


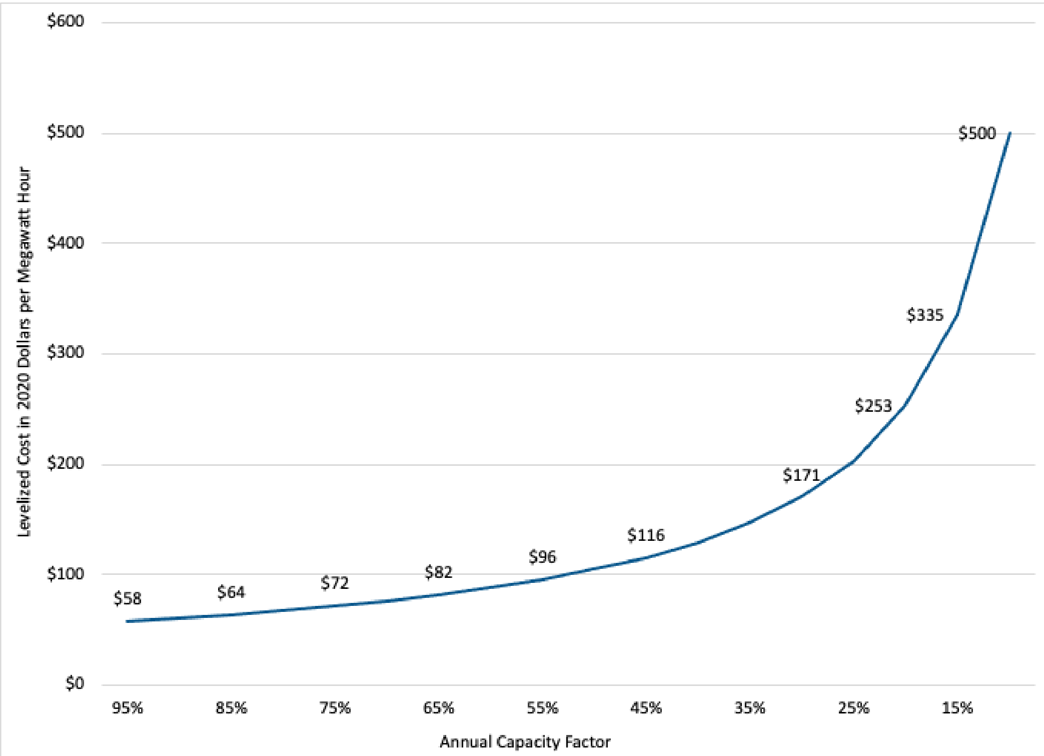
Fig. 5. Example of NuScale module load-following to compensate for generation from the Horse Butte wind farm and daily demand variation.

Source: D.T. Ingersoll, et al. Can Nuclear Power and Renewables be Friends? Proceedings of the International Congress on Advances in Nuclear Power Plants. May 2015.

The orange line in Figure 3 represents NuScale's load-following generation. The problem for NuScale is while its SMR technically may be able to both operate at a high capacity factor and load follow; it decidedly cannot do both at the same time. In the example above, total generation for the day comes to about 677 MWh, with the plant never topping 50 MW in any hour and falling below 10 MW for a couple of hours. For the day, this amounts to an hourly average of just over 28 MW. Based on the 60MW modules NuScale was projecting previously, this would be a 47% capacity factor for the day; using the 77MW figure now promoted by the company for each module, the daily capacity factor would fall to 36.6%.

Figure 4, below, is an illustration of how the target price of power from the NuScale SMR would increase if its annual capacity were assumed to be lower than the 95% projected by NuScale and UAMPS. For example, the target price of power from the SMR would jump to $72 per MWh if its capacity factor were 75% or to $141 per MWh if its annual capacity factor were assumed to be only 36.6% due to load following. This is because the fixed costs of operating and maintaining the plant, as well as annual capital costs, would be spread over fewer units of output (that is, megawatt-hours) as the capacity factor fell.

Figure 4: Estimated Price of Power From the NuScale SMR vs. the Plant's Capacity Factor



Source: IEEFA analysis using cost data presented in Attachment C to the November 2020 Development Cost Reimbursement Agreement between UAMPS and NuScale.

UAMPS claims that investing in the NuScale project would provide economic cost stability for participants.[31] However, that is improbable. Instead, as shown in Figure 4, the price of power from the SMR is more likely to be volatile, perhaps very volatile, as its capacity factor rises and falls depending on what problems the plant experiences and how much it is cycled in order to load follow renewable resources.

NuScale and UAMPS repeatedly claim that the NuScale reactor will be able to operate flexibly and, therefore, would be "capable of following variable resources like wind and solar." However, there is no actual operating experience or even testing at full-scale to support this claim.

Moreover, a paper written by personnel from NuScale, UAMPS, and Energy Northwest identified several potentially serious issues associated with the frequent cycling of the reactor.[32] Most importantly, the paper noted that "Routine thermal

[31] UAMPS. Presentation to the PUET Committee, page 13. October 20, 2021.
[32] D.T. Ingersoll, et. al. Can Nuclear Power and Renewables be Friends? Proceedings of the International Congress on Advances in Nuclear Power Plants. May 2015.

and operational cycling **will likely** cause components to degrade faster and may result in increased maintenance and lower module availability." [33] [emphasis added]

The paper also noted that:

> *... load following with a nuclear plant has several operational and economic impacts. Reactor operations are least impacted when changes in electrical output are accomplished by closing or opening the [turbine] bypass valve to redirect main steam flow from the turbine to the condenser. This can be done much more quickly than adjusting reactor power and allows for increased maneuverability of the plant's output. The drawback of this operation is that an excessive amount of energy is wasted in the form of turbine bypass flow and extended periods of high bypass flow to the condenser will tend to increase wear on the equipment, thus resulting in increased maintenance and equipment replacement.*[34]

This is an additional reason why it would be very unlikely, or even impossible, for the SMR to achieve the annual 95% capacity factor projected by NuScale and UAMPS, which will mean a higher price of power for project participants.

The paper concluded that "Ultimately, it will be economics, policy mandates and regulatory requirements that will drive the decision regarding the extent of load-following by the plant in an integrated nuclear-renewables environment."[35] Thus, nuclear and renewables ultimately may prove not to be such close friends after all.

Risk 5: The SMR Will Be Much More Expensive to Operate Than NuScale Claims

In addition to the costs of building a new reactor and the question of how well it will operate, other costs also affect how economic or risky a project will be. These include fuel costs, non-fuel operating and maintenance expenses, and certain other non-operating expenses, such as decommissioning costs and property taxes. These are generally lumped together and called production or generating costs.

Exhibit C of the November 2020 Development Cost Reimbursement Agreement between UAMPs and NuScale lists the fuel costs, other operating and maintenance expenses, and the capital costs that are used in the periodic modeling for the project's Economic Competitiveness Test (ECT).[36] When the fuel and non-fuel operating expenses listed in Exhibit C are added together and divided by the expected generation at a 95% capacity factor, it becomes clear that very low generating costs are underlying NuScale and UAMPs' $58/MWh target price and are used in UAMPs ECT modeling.

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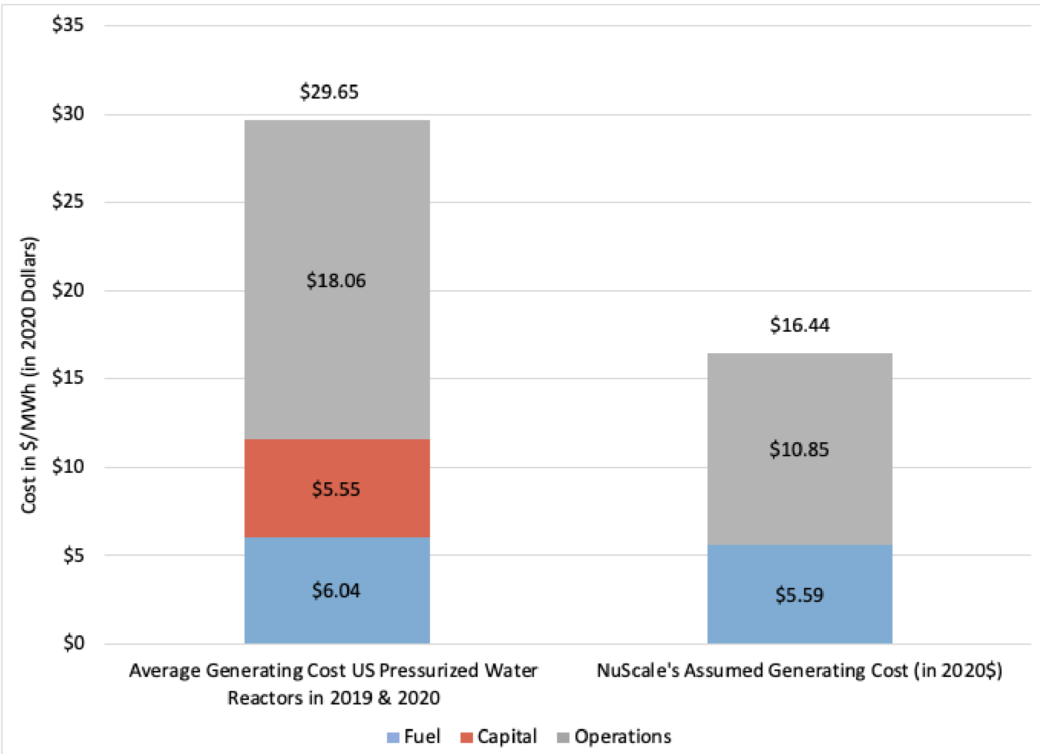
[33] *Ibid.*
[34] *Ibid.*
[35] *Ibid.*
[36] NuScale and UAMPS. Development Cost Reimbursement Agreement, page 29. November 2020.

Figure 5, below, compares the generating cost assumed by NuScale and UAMPS in the ECT with the average generating costs at U.S. nuclear power plants in 2017-2019. NuScale and UAMPS are assuming that the cost of generating electricity at the untested and unproven first-of-a-kind SMR will be 55% lower than the actual U.S. nuclear generating cost in 2019. This is simply not credible.

Figure 5: NuScale Estimate vs. Recent Generating Costs for U.S. Pressurized Water Reactors



Sources: Nuclear Costs in Context, NEI, October 2020 and 2019 and data in Attachment C to the November 2020 Development Cost Reimbursement Agreement between UAMPS and NuScale.

There are several other factors that need to be considered beyond emphasizing that the NuScale SMR will be a first-of-a-kind reactor.

First, NuScale and UAMPS ignore the annual capital costs (capex) that all other U.S. nuclear plants have had to spend for major maintenance and equipment repairs/replacements. These capex costs are not related to the plant's original construction cost. Instead, this annual capex represents investments that nuclear plant owners must make to address new or revised regulatory requirements or for major plant repairs or equipment replacements or improvements after it has begun commercial operations.[37]

Second, the Nuclear Energy Institute has explained that the data used to prepare Figure 5 actually does not represent the full costs of operating nuclear plants "as it

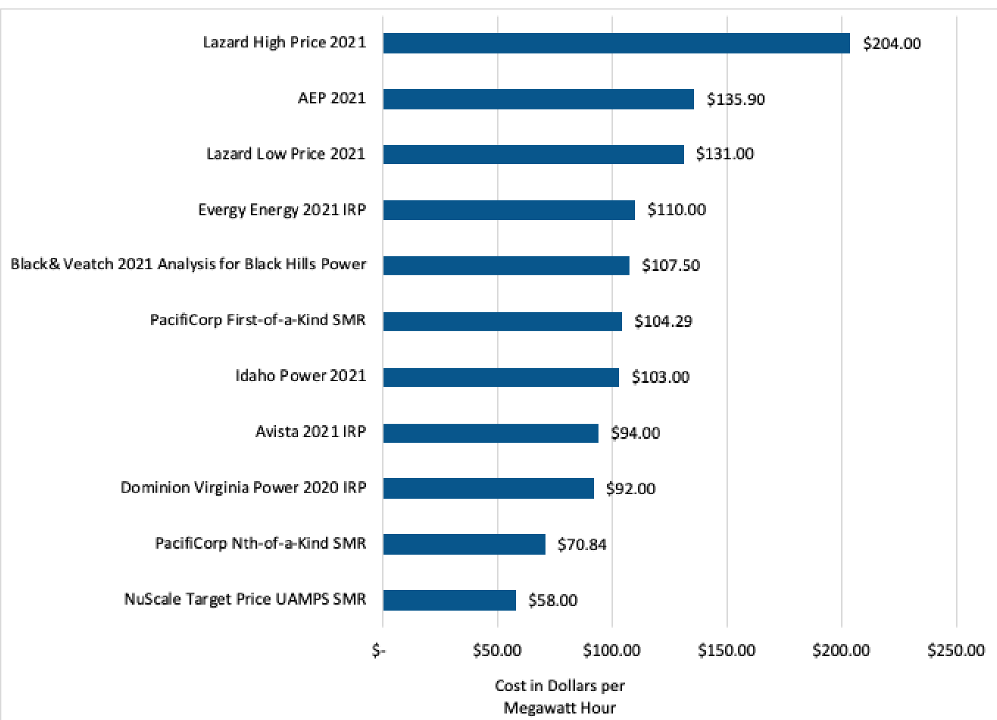
[37] Nuclear Energy Institute. Nuclear Costs in Context, page 4. October 2021.

does not include market and operational risk management (including but not limited to revenue uncertainty, equipment malfunctions and regulatory changes), property taxes, spent fuel storage costs, or returns on investment that would be key factors in decisions about whether to continue operating a particular station."[38] Thus, the average U.S. nuclear generating costs for the years 2019-2020 shown in Figure 5 are most probably understated, and the gap between those actual costs and NuScale's assumptions is even greater than Figure 5 would suggest.

Risk 6: UAMPS' Carbon Free Power Project Power Sales Contract Is a Blank Check That Will Cost Participants Far More Than $58/MWh

In its promotional literature, NuScale touts a target price of $58 per megawatt-hour (MWh) for energy from its SMR design. This, it says, makes the technology a viable competitor for future generation needs. Here again, however, the company's estimate is an outlier, with other, less entangled entities projecting much higher energy costs from future SMR developments.

Figure 6: Estimated Levelized Cost of Power From Small Modular Reactors



Source: Utility Integrated Resource Plans and Lazard's Levelized Cost of Energy Analysis – Version 15.0. October 2021.

[38] *Ibid.*, page 2.

To begin with, NuScale's $58/MWh price shown in Figure 6 is a non-starter, since it is calculated in 2020 dollars. By 2029, the soonest the first module is projected to be in service, that price, escalated at 2% per year, will have climbed to $69/MWh. More importantly, neither the $58 nor the $69 price is a guaranteed or actual price. Instead, it is just the currently estimated target price developed by NuScale and UAMPS through a modeling exercise about which very few details and no calculations have been released.

While NuScale and UAMPS tout this low target price, project participants risk having to pay much more than that. The Carbon Free Power Project Power Sales Contract signed by participating communities or utilities binds them to pay "**all of the costs and expenses associated with the Project**" regardless of whether the "**Project, or any portion thereof is acquired, completed, operable, operating, suspended or terminated, and notwithstanding the damage or destruction of the Project, the suspension, interruption, interference, reduction or curtailment of the Project Output, termination of any of the Project Agreements**, **loss or interruption of transmission from the Point of Delivery or termination of any Transmission Agreements, for any reason whatsoever, in whole or in part**."[39] [emphasis added]

In other words, participants' electricity costs will be based on the project's **actual costs** and not on the current promotional target price touted by NuScale and UAMPS. And participants will have to keep paying for the project no matter how expensive its electricity becomes or, indeed whether it produces any power at all.

Most importantly, this will not be a short-term commitment. Instead, participants will be bound to pay for the project in full unless they withdraw or the project is terminated during the licensing period (that is, prior to the start of construction). Specifically, the contracts state that participants are committed until the last of the following occurs:

> *(i) the date on which all of the Project Agreements have terminated or expired in accordance with their respective terms and all obligations of UAMPS thereunder have been fully paid, satisfied or discharged; (ii) the date on which all Bonds have been paid in full as to principal, premium and interest, or sufficient funds shall have been irrevocably set aside for the full defeasance therefore and all other obligations of UAMPS under the Financing Documents have been paid or satisfied; and (iii) the date on which the Initial Facilities and any Additional Facilities shall be permanently removed from service and Decommissioned and all Decommissioning Costs shall have been paid or fully funded.*[40]

Consequently, even if the project's actual electricity price is much higher than $58/MWh, as we expect it will be, and/or the SMR is not producing anywhere near as much power as NuScale and UAMPS currently claim it will (or indeed is not producing any power) participants will be contractually bound to pay off the bonds

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[39] UAMPS. Carbon Free Power Project Power Sales Contract. Sections 804(a) and 805(c), pages 48-49. April 1, 2018.
[40] *Ibid*, Section 202, page 18.

issued to finance construction. That is likely to be 40 years or longer given the typical duration of power plant construction bonds. As Section 805(c) indicates, participants will have to continue to pay even if the project produces no power or the plant is destroyed.

But withdrawing from the project after construction begins may be difficult, if not impossible, as it will require parties that want out to find a replacement and, if that replacement is not already participating in the project, to obtain approval from the Project Management Committee.[41] This could be a major problem because interest in the project has declined significantly recently, with energy subscriptions falling from 213 MW in October 2020 to the current 101 MWs.[42] Clearly, it is getting harder to find parties willing to bear the large risks associated with the project.

UAMPS states that the risk to participants is greatest in the earlier stages of the project.[43] This is untrue because the most significant risks for participants are cost increases and schedule delays during the construction and pre-operational testing phase of the project. Poorer than expected project operating performance and higher than projected operating costs also pose major risks for participants. Each of these risks could have dramatic impacts on the prices participants pay for the SMR because, as noted above, Section 805(a) of the power sales contract requires participants to pay all of the **actual costs and expenses** associated with the project and not merely the estimated target prices advertised by NuScale and UAMPS. And participants would have to pay these **actual costs and expenses** associated with the SMR for decades.

Risk 7: The Economic Competitive Test Offers No Meaningful Protection for Communities Buying Power From the NuScale SMR

UAMPS presents the Economic Competitive Test (ECT) as financial protection for the communities that sign the Power Sales Contract. However, upon close review, it is clear that the ECT is meant to offer UAMPS and NuScale much greater protection than it does any party that signs on to buy power from the NuScale reactor.

First, the ECT is not defined anywhere in the Power Sales Contract, not even in Section 101, *Definitions*. There also is no definition or listing of the criteria by which it is to be determined whether the project has passed or failed the ECT.

However, Article 3 of the Development Cost Reimbursement Agreement between UAMPS and NuScale does indicate that a failure of the ECT means that the calculated levelized cost of energy (LCOE) for the project from the ECT run is higher than the then current project target price, which is currently $58 per MWh.[44] If that happens,

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[41] *Op.cit.* Sections 303 and 304.
[42] UAMPS. Presentation to the PUET Committee, page 17. October 20, 2021.
[43] UAMPS. Presentation to Los Alamos County, page 6. July 21, 2021.
[44] UAMPS and NuScale. Development Cost Reimbursement Agreement, pages 4-7. November 2020.

UAMPS has the right to terminate or suspend the development cost reimbursement agreement with NuScale – *but it does not have to exercise that right*. In fact, it is unclear whether UAMPS, which clearly is heavily invested in the project, actually would terminate the agreement or instead, simply come up with a new target price.

Second, the ECT is being performed by NuScale and Fluor, two parties that clearly have a strong incentive to continue the project without any involvement or oversight by participants or independent parties. Allowing NuScale and Fluor to conduct the ECT without independent oversight is a clear conflict of interest.

Third, Section 504 (ii) of the Power Sales Contract states that "By a Super-Majority Vote, the Project Management Committee may determine to suspend or terminate the Project at any time <u>during the Licensing Period</u> upon its determination:

> *(ii) that the economic competitiveness test provided for in the Development Agreement has failed on any run date or that any price target contained in the Budget and Plan of Finance is not reasonably expected to be achieved."*[45]

However, the contract is silent regarding what will happen if the project fails an ECT after the conclusion of the licensing period, or even if any ECT is conducted after that time. In fact, there appears to be no requirement that the economics of continuing the project be re-evaluated after the end of licensing period for any reason, including significant construction schedule delays or cost increases.

Fourth, UAMPS has indicated that the ECT only compares the levelized cost of the reactor project with the cost of power from a natural gas generator even though the costs of solar, wind and battery storage capacity have declined dramatically over the past decade and are expected to continue to decline in the years ahead. Thus, there certainly might be lower cost alternatives to the reactor project than a natural gas-fired generator.

Fifth, the Power Sales Contract does not provide any guarantee that participants and their ratepayers will pay only the designated target price, which was previously $55 per MWh and now is $58 per MWh. Instead, participants will have to pay the project's actual costs and expenses.[46] Nor does the Development Cost Reimbursement of the Power Sales Contract describe the methodology by which the dollar per MWh estimated target prices have been determined.

Sixth, the contract does not afford participants the opportunity to initiate litigation against NuScale or Fluor for mismanagement of the design and/or operation of the reactor if UAMPS declines to initiate such litigation.

Finally, Section 403 of the power sales contract states that the Project Management Committee shall "… review the results of each run of the economic competitiveness test performed pursuant to the Development Agreement and the projected levelized cost of energy from the Initial Facilities, and review and approve all directions, actions and notices to be given or made by UAMPS under the Development

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[45] UAMPS. Carbon Free Power Project Power Sales Contract, pages 29-30. April 1, 2018.
[46] *Ibid.*, page 48.

Agreement."[47] However, it is not required that the results of each ECT run and information about how the projected levelized costs were developed be given to the officials or the ratepayers of participating communities.

Instead of this opaque review conducted by parties self-interested in the continuation of the NuScale SMR project, any economic assessment should:

- Be conducted by an independent third party that would not benefit whether or not the project is continued;
- Be fully transparent regarding its methodology, assumptions, calculations and results;
- Include a wide range of zero-carbon alternatives including wind, solar, storage and load management resources;
- Reflect resource offers received through a competitive power procurement process.

Renewable Resources and Battery Storage Will Provide Reliable Electricity at Lower Cost Than NuScale's SMR

The growth in renewable solar and wind resources over the next decade and beyond will reduce the region's CO_2 emissions and eliminate any need for the NuScale reactor.

Renewable and battery storage resources have several advantages over the NuScale SMR.

1. They can be built faster, thereby being available to the grid in significantly less time than the eight years that NuScale claims for the first module of its reactor.
2. They have a proven track record of declining costs over the long term.

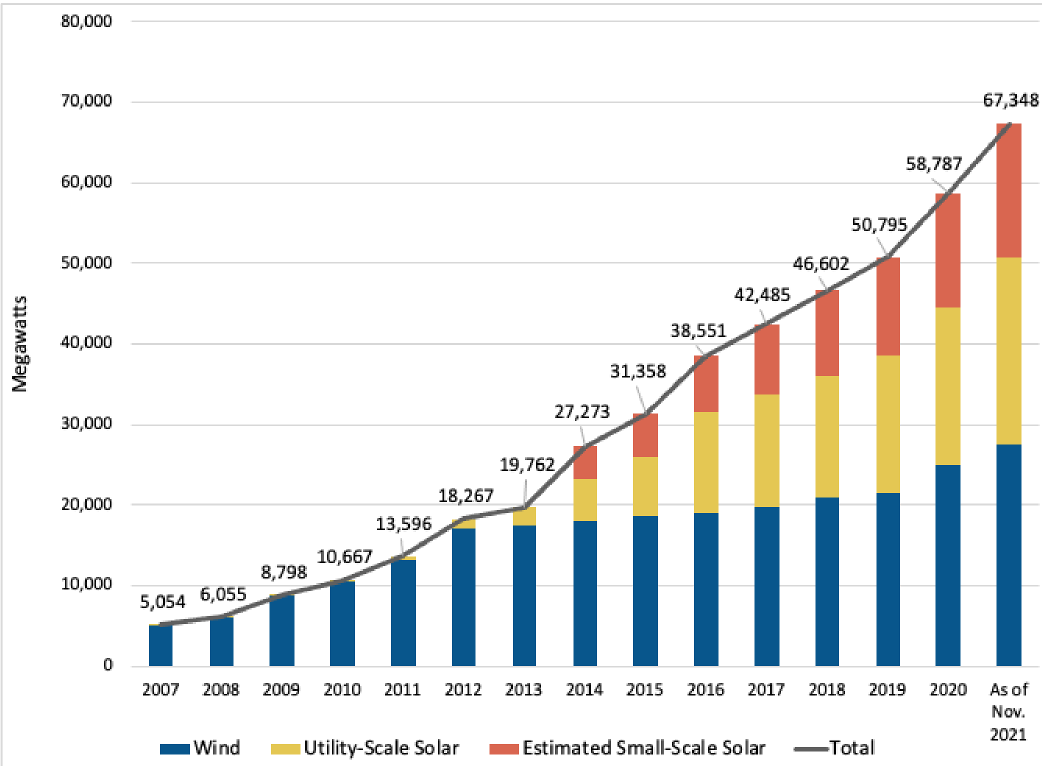
Little is certain about the actual cost, commercial operation date or reliability of NuScale's SMR. But it is certain that by the time it is completed, there will be significantly more utility-scale wind, solar and battery storage capacity installed across the western U.S. This, in turn, will put downward pressure on power prices and ratchet up the commercial competition for NuScale.

[47] *Ibid.*, pages 25-26.

A. The Western Grid Will Be Very Different in Coming Years

The amount of utility-scale solar and wind on the Western grid increased more than nine-fold between 2007 and 2020 and this increase is likely to be dwarfed by the growth in these resources over the next decade or so.

Figure 7: Growth in Installed Solar and Wind Capacity in U.S. Western States, 2007-November 2021



Sources: Utility-Scale Solar 2021, Tracking the Sun 2021 and Land Base Wind Market Report from the Berkeley Lab and Form EIA-861M detailed data.

A lot of the growth in installed solar capacity shown in Figure 7 has been through the California Independent System Operator (CAISO) as the state of California worked to meet the legislative mandate that 33% of electricity sales in 2020 and 60% of sales in 2030 be from renewable resources.[48]

However, other states also have been moving to replace fossil-fired generation with renewable resources. For example, Colorado has adopted a GHG Pollution Reduction Roadmap that provides a pathway to reduce the state's greenhouse gas emissions (GHG) 50%, by 2030, including achieving an 80% reduction in electricity sector GHG emissions.[49]

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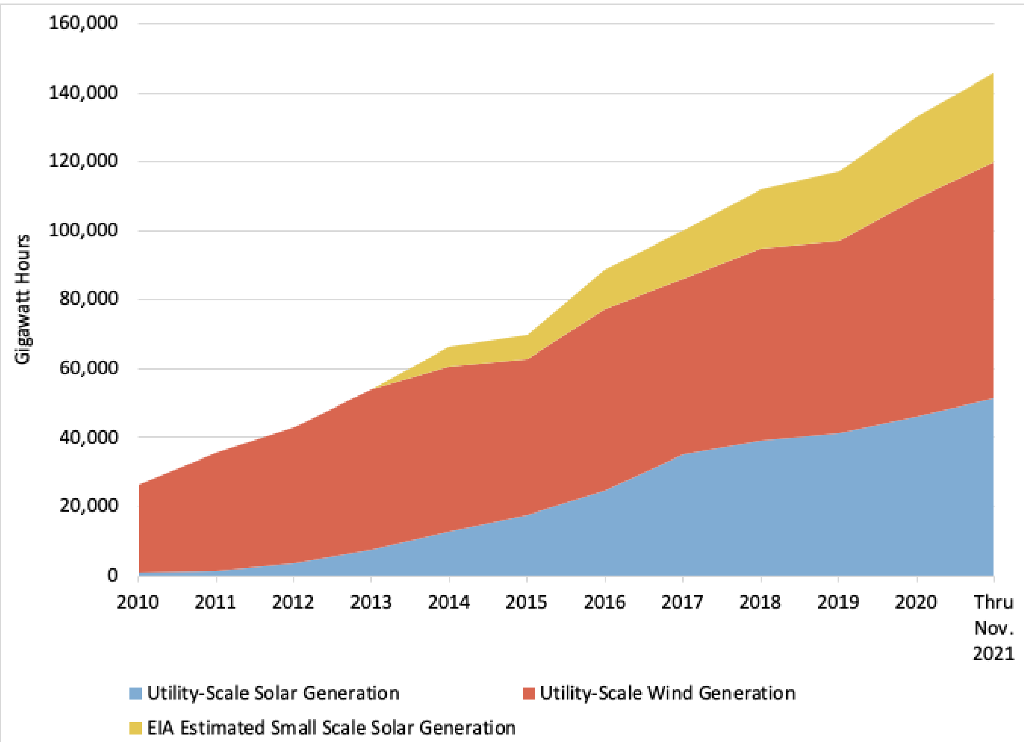
[48] California Legislative Information. SB-100 California Renewables Portfolio Standard Program: Emissions of Greenhouse Gases. September 10, 2018.
[49] Colorado Energy Office. Colorado GHG Pollution Reduction Roadmap. January 14, 2021.

UAMPS has been part of this move towards cleaner energy as it signed a contract with the NTUA Generation-Utah, LLC, a subsidiary of the Navajo Tribal Utility Authority (NTUA) in 2019 for 66 MW of solar to begin in June 2022. The starting price was $23.15/MWh with a 2% annual escalator.[50]

The annual generation from solar and wind resources in the West has also grown more than six-fold in the past decade as the following graphic illustrates.

Figure 8: Growth in Annual Wind and Solar Generation in Western U.S. States, 2007-November 2021



Source: EIA Electric Power Monthly.

Complementing this, CAISO already added 2,100 MW of battery storage capacity by early December of 2021 and, according to Platt's Analytics plans to add another 2,000 MW before next summer.[51]

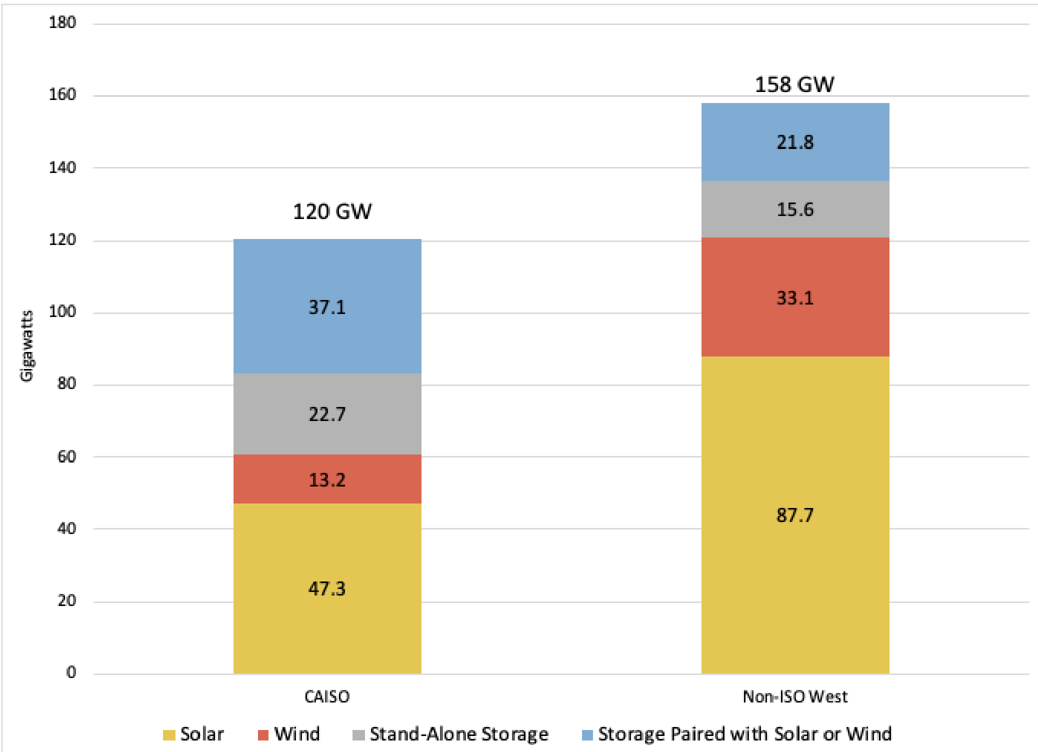
But this dramatic growth is only the beginning of a wave of new solar, wind and battery storage capacity expected to be built in the region over the next decade.

Reviews by Lawrence Berkeley Lab found that as of the end of 2020 there was nearly 280,000 MW of proposed solar, wind and battery storage capacity in the

[50] UAMPS. UAMPS members add solar energy to resource mix. July 2019.
[51] Platts. Western US power markets face tough winter, work to build summer supply. December 30, 2021.

active utility and regional interconnection queues in the western U.S., although it recognized that not all this capacity in the queue would be built. [52]

Figure 9: Solar, Wind and Battery Storage in Western Interconnection Queues at End of 2020



Sources: Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2020; Utility-Scale Solar 2021 Edition, Land Based Wind Market Report, all from Berkeley Lab in 2021.

Perhaps most significantly, 89% of the proposed solar capacity and 37% of the proposed wind capacity in CAISO and 67% of the proposed solar capacity and 13% of the proposed wind capacity in the non-ISO West at the end of 2020 was paired with battery storage.[53] Also, the capacity shown in Figure 9 only counts utility-scale projects. Small-scale solar and storage projects, which also are expected to grow rapidly, are not included.

Moreover, the amount of solar and storage in western interconnection queues has swelled over the past year, according to a recent report by S&P Global titled "Western US at forefront of surging solar-plus-storage market."[54] For example, in CAISO the amount of solar paired with storage on the interconnection queue had

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[52] Berkeley Lab. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2020, page 19. May 2021.
[53] Berkeley Lab. *Op. cit.*
[54] S&P Global, January 27, 2022.

increased to more than 71,550 MW, as of January 5, 2022, and the amount of storage with solar had increased to 63,947 MW.[55]

Not all of the capacity in interconnection queues will get built eventually but even if only a significant portion does, it would more than double the amount of renewable capacity and battery storage that has been added over the past decade.

As more renewable capacity comes online in the West, there is also a major push under way to better integrate the regional electricity market. This is being driven particularly by the Energy Imbalance Market (EIM), "a real-time wholesale energy trading market that enables participants anywhere in the West to buy and sell energy when needed."[56] One of its goals is to find and deliver the lowest cost energy to consumers.[57] And, by optimizing resources from a larger and more diverse pool, it is able to better facilitate the integration of renewable energy that otherwise may be curtailed at certain times of the day. The EIM also has enhanced reliability by increasing operational visibility across electricity grids and improving the ability to manage transmission line congestion across the region's high-voltage transmission system.

The Western Energy Imbalance Market provides for grid reliability in several key ways.

First, the extended footprint of EIM – which will include parts of 10 U.S. states and a portion of the Canadian province of British Columbia by 2023 – provides access to a broad pool of resources across balancing areas and allows for wide geographic diversity in the siting of solar and wind farms. This, in turn, significantly reduces the risk that an adverse weather or other grid event, or even the passage of clouds on an otherwise sunny day, will reduce or eliminate generation from a substantial portion of solar or wind resources. In this way, the variability from many solar and/or wind resources can be smoothed out.

Second, the EIM redispatches the system every five minutes. Five-minute dispatch is currently the norm in independent system operators (ISOs) throughout the country. It helps manage the variability of solar and wind generation. Faster dispatch also enables more efficient balancing of the grid as load and generation levels can be more closely matched as it can be based on the most updated weather, demand and variable renewable energy forecasts. Five-minute dispatch thus helps system operators to better forecast real-time operations.

There are currently 15 members in the EIM, including CAISO; PacifiCorp, Puget Sound Electric, and Portland General Electric in the Northwest; and APS and NV Energy in the Southwest. Another seven utilities, including the Bonneville Power Authority, Avista, Tacoma Power and the WAPA Desert Southwest Region are

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[55] Berkeley Lab. *Op. cit.*
[56] CAISO. Western Imbalance Market. Western EIM How it Works.
[57] CAISO. Western EIM benefits reach $801.07 million since its launch in 2014. News Release, October 30, 2019.

scheduled to join by 2023, meaning that participants representing well over 80 percent of the load in the Western Interconnection will be active in the EIM.[58]

Last November, CAISO launched a stakeholder design process to expand the Western EIM into a day-ahead time frame where the overwhelming majority of energy transactions occur. According to CAISO, expanding into a day-ahead market "would bring greater economic and environmental benefits to electricity consumers and make it easier for energy providers across the Western United States to work together to share diverse resources for enhanced reliability."[59]

At the same time, groups of utilities are exploring other ideas for improving regional integration. One of these is the Northwest Power Pool (NWPP), a voluntary association of utilities in the Pacific Northwest, which last August hired the Southwest Power Pool to design a resource adequacy program for the association. The Southwest Power Pool operates the regional market and grid in the middle of the United States. Members of NWPP include Avista, BC Hydro, the Bonneville Power Administration, Idaho Power, NorthWestern Energy, PacifiCorp and Puget Sound Energy.[60]

More recently, another group of electric utilities has announced plans to evaluate regional market solutions. Members of the informal Western Markets Exploratory Group (WMEG) have said that they are exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing state regulations.[61] The group hopes to identify market solutions that can help achieve carbon reduction goals while supporting reliable, affordable service for customers.

Even if these efforts don't eventually lead to the creation of a fully integrated Western market and grid, they will increase access of utilities in the Northwest to low-cost solar energy from California and the Desert Southwest and improve overall grid reliability.

[58] The Western Interconnection power grid serves over 80 million people in 14 western states.
[59] CAISO. California ISO formally kicks off Extended Day-Ahead Market design stakeholder process. November 10, 2021.
[60] Utility Dive. Pacific Northwest looks to avoid California-style blackouts through more regional coordination. August 24, 2020.
[61] Business Wire. Several Western Power Providers Announce Plans to Explore Market Options. October 5, 2021.

B. Renewable Resources, Battery Storage, Demand-Side Resources, Supported by the Region's Hydro Capacity, Will Provide a Secure and Reliable Electricity Grid Without the NuScale SMR

The Grid of the Future Will Not Need Capacity Like NuScale's SMR to Complement or Load Follow Variable Renewable Resources

The U.S. electricity grid was originally dependent almost completely on large, central-generating stations powered by coal and oil. Starting in the 1960s, new nuclear units also were added. These units were called "baseload" because they ran as much as possible to help meet the 24-hour system base demand and in this way spread their high fixed costs over as many units of output (that it, megawatt hours) as possible.

However, a series of developments in the last decades of the 20th century and first decades of this century have turned this paradigm around. First, the cost of building new nuclear plants skyrocketed in the 1970s and 1980s. During these years, the rate of demand growth for electricity fell, sometimes even becoming negative. The spread of competitive power procurement to more than half of U.S. power markets required proposed nuclear power to be economically competitive with other forms of generation, a challenge that it has never met. As a result, only one new nuclear plant has been completed in the U.S. since the mid-1990s.

Subsequently, the prices of building new coal plants also rose dramatically. At the same time, public concern over the environmental and health impacts, including but not limited to climate change, of relying on oil and coal led to the retirement of an increasing number of power plants and the cancellation of proposals for more than another 150. Then natural gas prices collapsed in 2008 and 2009, making building and running gas-fired generators less expensive even than running many coal and nuclear plants. Finally, the dramatic cost declines in solar, wind and storage prices, and substantial improvements in operating performance have meant that the grid no longer needs to depend on a limited number of large power plants. Instead, the new paradigm involves fast-growing numbers of flexible and dispatchable solar and wind farms located at geographically diverse sites, often with grid-scale storage batteries, and increasing numbers of distributed energy resources (rooftop solar). This new grid, without large conventional fossil and nuclear "baseload" plants is the one against which the NuScale SMR proposal should be evaluated.

Solar and Wind Generation, Storage and Load Management Can Provide Essential Grid Reliability Services

Although it is true that solar and wind are variable generating sources – that is, the sun doesn't shine at night and the wind doesn't blow all the time – several factors enhance the capacity of the grid to reliably integrate growing amounts of these renewable resources.

First, the development of advanced inverter power controls has enabled stand-alone[62] wind and solar resources to respond almost instantaneously to threats to grid stability posed by imbalance between supply and demand that arise, for example, when a large generator goes offline or when a portion of a solar farm stops producing electricity due to the passage of a cloudbank. In fact, the technical ability of standalone wind and solar resources to provide essential reliability services has been extensively demonstrated through studies, tests and operating experience.[63]

CAISO and the National Renewable Energy Laboratory (NREL) have conducted tests to determine the capacity of wind and solar resources to provide essential grid reliability services because widespread concerns were being voiced as higher levels of renewable resources were being integrated into the grid.[64] These tests showed that commercial sized wind and solar PV resources could provide essential grid reliability resources such as voltage support, ramping, frequency response and load following. [65] The testing also showed that the performance of these resources was comparable to, or better than, conventional resources."[66]

Second, steep declines in battery costs and an increased need for grid flexibility have led to a dramatic increase in storage because fast-acting grid-scale battery storage can provide a number of services including, but not limited to, firming the variability in solar and wind generation and providing essential grid reliability support. A 2020 global survey by the IEEE Power & Energy Society found that "Energy storage is one of the most important strategic technologies for power system operators around the world and is also the first priority of technical standards and regulatory support needs."[67]

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[62] Stand-alone means that the solar or wind facility is not partnered with on-site battery storage.
[63] Berkeley Lab. Variable Renewable Energy Participation in Ancillary Services Markets: Economic Evaluation and Key Issues, slide 6. October 2021; Wind Energy Science. Ancillary services from wind turbines. 2020; and NREL. Variable Renewable Generation Can Provide Balancing Control to the Electric Power System. September 2013.
[64] CAISO. FAQ: Using Renewables to Operate a Low-Carbon Grid, California ISO, NREL, and First Solar. January 2017.
[65] CAISO. Using Renewables to Operate a Low-Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar Plant, 2017, pages 5 and 55; and CAISO, NREL, Avangrid Resources, and General Electric. Avangrid Renewables Tule Wind Farm: Demonstration of Capability to Provide Essential Grid Services. March 2020.
[66] CAISO, *Op. cit.*
[67] IEEE Power & Energy Society. Maintaining Electric Reliability with Changing Resource Mix; Testimony at FERC 2021 Reliability Technical Conference, page 6. September 2021.

For example, the battery can be charged when loads and prices are low and discharged during more expensive hours when loads are higher.[68] This can both act as a hedge against renewable variability and reduce the curtailment of emissions-free renewable energy generation.[69] Battery storage also can be used to ensure that there is adequate firm or peaking capacity during periods when variable solar or wind energy is unavailable.[70]

In addition, battery storage can be a suitable resource for short-term reliability services, such as Primary Frequency Response and Regulation, due to the ability of batteries to charge or discharge very quickly, faster than conventional resources.[71] As NREL has explained, "appropriately sized [battery storage] can also provide longer duration services, such as load-following and ramping services, to ensure that supply meets demand" and the power system remains operates reliably.[72]

NREL also has explained that "Deploying battery storage also can help defer or circumvent the need for new grid [transmission and distribution system upgrades] by meeting peak demand with energy stored from lower-demand periods, thereby reducing congestion and improving overall transmission and distribution asset utilization."[73]

Utility-scale battery storage can be deployed in the transmission network, the distribution network near load centers or co-located with variable renewable energy generators depending on the need and economics. For example, Rocky Mountain Power is seeking to develop distributed solar-plus-storage grid assets in Utah, first by participating with solar and battery developers in building a new 600-unit all-electric and energy efficient apartment complex. Each apartment will have its own solar panels and storage battery. Each battery will be controlled by the utility and all 600 batteries will work together to provide power to the grid, as needed.[74]

Rocky Mountain Power also is partnering with a battery manufacturer and a solar contractor to offer incentives for its 50,000 current solar customers in Utah to add a battery system to create a virtual power plant.[75] The power from the new batteries would increase the distributed power capacity that the utility can dispatch to the grid in the same way that solar-plus-storage assets dispatch their storage

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[68] NREL. Grid-Scale Battery Storage: Frequently Asked Questions and IEEE Power & Energy Society. Maintaining Electric Reliability with Changing Resource Mix; Testimony at FERC 2021 Reliability Technical Conference.
[69] *Ibid.*
[70] *Ibid.*
[71] *Ibid.*
[72] *Ibid.*
[73] NREL. *Op. cit.*
[74] UtilityDive. The future of energy storage is here: An inside look at Rocky Mountain Power's 600-battery DR project. September 30, 2019.
[75] UtilityDive. Rocky Mountain Power's distributed battery grid management system puts Utah 'years ahead' of California. October 14, 2021.

batteries.[76] The company also has filed a version of the incentive program in Idaho and is evaluating it for all six states in which parent company, PacifiCorp, operates.

The North American Electric Reliability Corporation (NERC)[77] and the Western Electricity Coordinating Council (WECC)[78] have recently completed an assessment of battery energy storage systems that concluded that as variable renewable energy generation, primarily from wind and solar resources continue to grow, storage can enhance grid reliability by offsetting resource variability and providing essential reliability services, such as voltage support and frequency response. [79] In fact, in March 2021 NERC's president and CEO testified before the Senate Energy and Natural Resources Committee that "Energy storage can and will be a game changer."[80]

Almost all the existing and proposed battery storage projects in the U.S. rely on lithium-ion chemistry, which is effective for 3-6 hours. However, the promise of game-changing longer-duration battery storage is starting to come to fruition as batteries using iron-flow technology – a technology that Bloomberg Green says "could eat lithium's lunch"[81] – are starting to be deployed at commercial scale as SB Energy Corp. has announced a deal to purchase two gigawatt hours of batteries from ESS, the U.S. manufacturer, over the next five years.[82] The new ESS batteries use iron, salt and water to provide an alternative to lithium ion batteries. Maximum storage time for the new batteries is 12 hours.[83] ESS specifies an operating life for the iron-flow batteries of over 20,000 cycles, equivalent to more than 20 years of expected use, or far longer than the 7-10-year lifecycle for conventional battery chemistries.[84] Other technologies for extending the number of hours battery storage can be effective also are being researched and developed.

Hydro resources in the West also have the flexibility to back up wind and solar resources. For example, the Bonneville Power Authority (BPA) is mandated to market the power from 31 federal hydroelectric projects with a total capacity of 22,442 MW, as well as a nuclear plant and several other facilities.[85] As BPA explains on its website, this renewable hydropower plays a significant role in maintaining a stable and reliable grid by balancing supply and demand and it allows for the

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[76] *Ibid.*
[77] NERC is a regulatory authority that has been designated as the Electric Reliability Organization for the United States with the mission of assuring the effective and efficient reduction of risks to reliability and security of the Bulk Power System.
[78] WECC is a non-profit corporation that exists to assure a reliable Bulk Electric System in the geographic area known as the Western Interconnection.
[79] NREL. *Op.cit.*
[80] NERC. Testimony of James B. Robb before the Committee on Energy and Natural Resources, United States Senate. March 11, 2021.
[81] Bloomberg Green. Iron Battery Breakthrough Could Eat Lithium's Lunch: Iron-flow technology from ESS is being deployed at scale in the U.S. September 30, 2021.
[82] Wood Mackenzie. ESS-SoftBank battery deal heralds a new Iron Age: The deployment of iron flow storage technology at scale represents an important energy transition milestone, October 8. 2021.
[83] *Ibid.*
[84] *Ibid.*
[85] Bonneville Power Administration. BPA Facts, 2020.

growth of other renewable resources. In fact, by adjusting the amount of water flowing through the dams, hydropower can be increased or decreased very quickly to meet changes in demand for power.[86]

In the grid of the future, battery storage and hydropower will be able to firm up the variable generation from renewable solar and wind resources while ensuring that the grid remains stable and reliable without the proposed NuScale reactor. Load management also can play a significant role in this transition while making the grid more reliable and resilient.

The first way that load management can do this is energy efficiency which reduces demands on the grid during all hours, including the periods of peak use.

A second option is demand flexibility which means taking advantage of the latent flexibility in how customers use electricity to shape and shift that use to better match grid needs (that is, to better balance supply and demand). As a recent Issue Brief from the Union of Concern Scientists explains, small adjustments in how and when customers use electricity allows greater use of low-cost, zero-carbon electricity whenever and wherever it is produced.[87] This is not a new concept as utilities have long had demand-response programs where customers have been paid to reduce their usage and, hence their demands on power from the grid, during periods of peak usage.

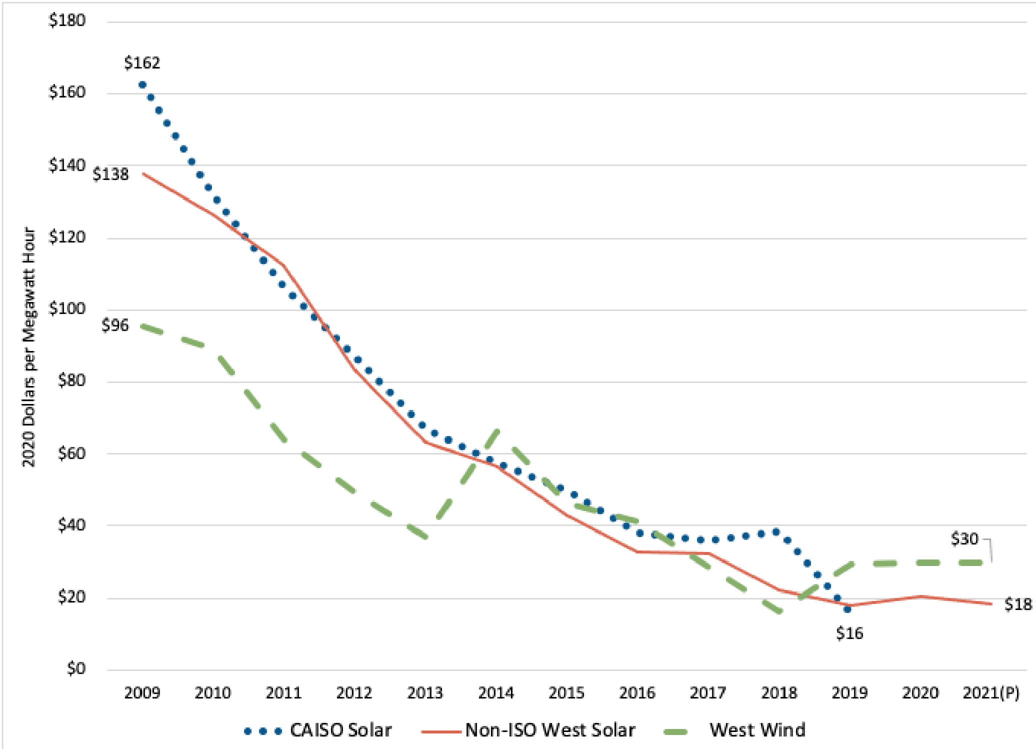
C. Unlike Nuclear Costs, Wind, Solar and Storage Prices All Have Declined in Recent Years, and Further Declines Can Be Expected in the Future

The booming interest in renewables and storage is due primarily to three factors: dramatic declines in installed costs; improved operating performance; and increased awareness of the need to take action now to address the threat posed by climate change.

For example, as shown in Figure 10, below, average solar PPA prices in CAISO and the Non-ISO West declined by 89% and 87%, respectively between 2009 and 2021. Average wind PPA prices declined by 69% during the same period.

[86] Bonneville Power Administration. Hydropower in the Northwest.
[87] Union of Concerned Scientists. The Flexible Demand Opportunity: How Smarter Electricity Use Can Support a Clean Energy Future, January 22, 2020.

Figure 10: Declining Solar and Wind PPA Prices in the West



Sources: Utility-Scale Solar 2021 Edition and Land Based Wind Market Report, both from Berkeley Lab, 2021.

Similarly, average battery storage costs fell by 72% between 2015 and 2019, according to a new analysis by the U.S. DOE's Energy Information Administration (EIA).[88]

Renewables prices are expected to continue their decade long declines over the long-term.[89] For example, NREL projects that battery storage capital costs will decline by 28-58% by 2030 and by 28-75% by 2050.[90]

Prices are expected to increase over the next year because of supply chain constraints, increased shipping costs and rising prices for key commodities, such as steel.[91] But the price bump expected through 2022 won't only affect renewable projects. The prices of other power plant projects, such as NuScale's reactor, also could increase. For example, NorthWestern Energy in Montana decided to withdraw an application to build a new gas-fired generator due to pandemic-related supply chain challenges and, instead, to proceed directly to construction to take advantage

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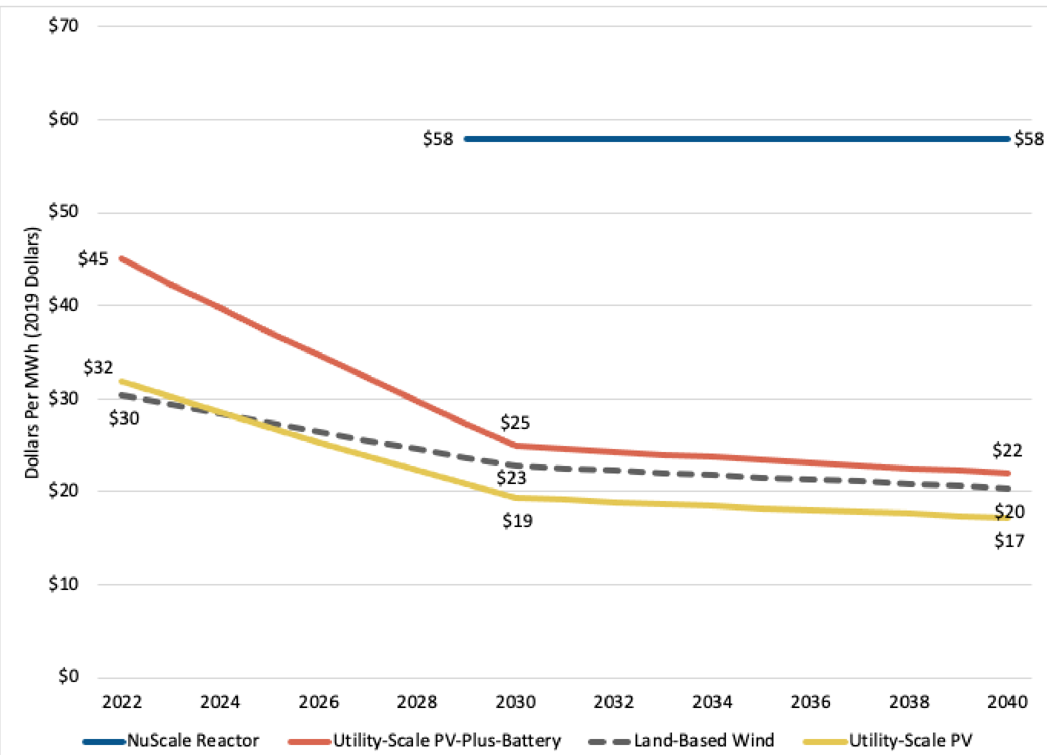
88 EIA. Battery Storage in the United States: An Update on Market Trends, August 2021.
89 NREL. Annual Technology Baseline, Electricity Update. 2021.
90 NREL. Cost Projections for Utility-Scale Battery Storage: 2021 Update. June 2021.
91 Lazard. Lazard Releases Annual Levelized Cost of Energy, Storage and Hydrogen Analyses, October 28, 2021; UtilityDive. Supply chain woes expected to raise 2022 costs for renewables, Lazard LCOE report finds, November 1, 2021; and UtilityDive. US solar price see first cross-segment rise since 2014, bucking downward trend, report finds. September 15, 2021.

of the favorable supply and price terms in its current contract for their proposed gas-fired project.[92]

Figure 11 on the following page compares NuScale and UAMPS's $58 per MWh target price for power from the proposed reactor with NREL's projected levelized costs of energy (LCOE) for land-based wind, utility-scale PV, and utility-scale PV-Plus-Battery. This chart shows that NuScale's target price for the power from the proposed reactor is much higher than the prices that potential participants can expect to pay for power from renewable alternatives.

Figure 11: NuScale's Target Price for Power from Its Proposed Reactor Is Much Higher Than the Projected Cost of Power From Renewable Alternatives[93]



Sources: UAMPS Presentation to Los Alamos County, July 21, 2021, p. 4; National Renewable Energy Laboratory, 2021 Annual Technology Baseline: Utility-Scale PV-Plus-Battery.

Indeed, it is reasonable to conclude that this chart actually understates by a significant amount the difference between NuScale's target price for power from the reactor and the cost of power from alternative renewable resources because, as explained above, it is very likely that the cost of building the reactor will be much

[92] Billings Gazette. NorthWestern changes Laurel power plant plans, September 21, 2021.
[93] Berkeley Lab. Levelized PPA prices generally track the LCOE of wind Utility-Scale Solar. See Utility-Scale Solar, 2021 Edition, slide 34. October 2021. and Utility-Scale Wind and Solar in the U.S., Comparative Trends in Deployment, Cost, Performance, Pricing, and Market Value, slide 2. December 8, 2020.

higher than NuScale and UAMPS now claim; it will take longer to build the reactor, meaning that escalation and financing costs will be greater; the reactor will not achieve a 95% capacity factor; and it will cost far more to operate and maintain the reactor than NuScale and UAMPS have assumed in their calculations. Power from the NuScale reactor would not even be the lower cost alternative if the future prices of land-based wind, utility-scale PV, and utility-scale PV-Plus-Battery are significantly higher than NREL has recently projected.

Conclusion

There are serious problems with the proposed NuScale SMR project.

The first set of problems revolve around the company's optimistic assumptions regarding its untested, first-of-a-kind reactor. NuScale claims it will be able to accomplish a performance trifecta that has never been accomplished:

- Completing construction at the new facility in 36 months or less;
- Keeping construction costs in check and thereby meeting a target power price of less than $60/MWh; and
- Operating the plant with a 95% capacity factor from day one.

As this report has demonstrated, these are unduly optimistic assumptions. Costs and construction times for all recent nuclear projects have vastly exceeded original estimates and there is no reason to assume the NuScale project will be any different. For example, costs at Vogtle, the project most like NuScale in terms of modular development, now are 140% higher than the original forecast and construction is years late with significant uncertainty about a final completion date.

The second set of problems with the NuScale proposal are contractual. As the power sale agreement is currently structured, anyone who signs on to buy power from NuScale's SMR will have to pay the actual costs and expenses of the project, not just the $58 per MWh estimated target price now being promoted by NuScale and UAMPS. And participants would have to continue to do so for decades, even if the price of the electricity from the SMR is much more expensive than NuScale and UAMPS now claim or even if participants don't receive any power from the project for a significant part of its forecast operating life. These are risks that far outweigh any potential project benefits.

The third set of problems with the NuScale project are ones of comparison. The NuScale SMR will not be online until 2029 at the earliest. In the interim, thousands of megawatts of new wind, solar and battery storage are going to be added to the electric grid, reducing carbon dioxide emissions immediately and undercutting the need for the reactor project. Additional experience integrating variable generation resources and a broad utility effort to better integrate the Western grid will also serve to eliminate the need for the NuScale reactor.

In sum, there are cheaper zero-carbon energy options available now. NuScale's SMR is not needed.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

About the Authors

David Schlissel

Director of Resource Planning Analysis David Schlissel is a long-time consultant, expert witness, and attorney on engineering and economic issues related to energy. He has testified in more than 100 court proceedings or cases before regulatory bodies.

Dennis Wamsted

Analyst/Editor Dennis Wamsted has covered energy and environmental policy and technology issues for 30 years. He is the former editor of The Energy Daily, a Washington, D.C.-based newsletter.