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Small Modular Reactors, Carbon Capture: The Wrong Resources for Colorado's Energy Transition

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Key Findings

Proposals for unproven and expensive SMR and gas with carbon capture technologies put PSCo's ratepayers at risk of significant future rate increases.

The already high costs of SMRs, coupled with uncertain construction lead times and potential additional costs make the technology a huge risk for Colorado and its ratepayers.

Carbon capture is an unproven technology for gas-fired generation: its performance is uncertain and its costs are unknown.

Renewable energy parks with wind and solar resources, battery and long-term storage, and flexible loads, should be evaluated as alternatives to SMRs and gas with carbon capture.

Executive Summary

Colorado is transitioning away from coal as an electricity generation resource. How those resources are replaced is a key long-term discussion that has major implications for ratepayers of Public Service of Colorado (PSCo) and the state as a whole. The wrong choices will be costly and delay the transition.

This report focuses on two options, construction of new nuclear reactors or gas-fired turbines with carbon capture. These technologies have been pushed into the forefront by a statewide proceeding involving PSCo (technically called the Just Transition Solicitation, or JTS) that is focused on how to replace the output from Unit 3 at the coal-fired Comanche power plant in Pueblo, which is scheduled to shut down in 2030.[1]

In August, the Colorado Public Utilities Commission approved creation of the Carbon Free Future Development (CFFD) fund to allow PSCo, a subsidiary of Xcel Energy, to study replacement generation options that are not yet commercially available. The $100 million fund will be paid for by PSCo ratepayers.

The utility says the fund will help it "de-risk" the development of promising new technologies. IEEFA supports technology research but disagrees with PSCo's assessment of the fund's impact on risk. There will still be plenty of risk, both economic and technological—but it now will be borne by ratepayers, not shareholders.

An earlier report prepared by the Pueblo Innovative Energy Solutions Advisory Committee (PIESAC) also touted unproven nuclear and carbon capture options as the best means of replacing the output from Comanche 3, which will complete PSCo's transition away from coal-fired generation.[2] The committee's recommendations are also part of the testimony in the JTS process.[3]

Our analysis takes an in-depth look at small modular reactors (SMRs) and gas with carbon capture. We conclude that neither are viable options due to major technological and economic hurdles and that using ratepayer money through the CFFD to fund their development is ill-advised.

IEEFA believes the community and people of Pueblo deserve the support of PSCo's ratepayers and Colorado's taxpayers during the transition away from coal by siting new replacement resources in

[1] The 1,636-megawatt (MW) Comanche coal plant comprises three units: Unit 1, with a nameplate capacity of 383 MW, was built in 1973 and retired in 2022; Unit 2, at 396 MW, was built in 1976 and is scheduled to be retired this year; Unit 3, at 857 MW, came online in 2010, making it one of the newest coal units in the country. However, it has been plagued by operational issues and PSCo agreed to retire the plant by the end of 2030, more than 40 years early, as part of a settlement agreement approved by the Colorado Public Utilities Commission.
[2] PIESAC. Pueblo Innovative Energy Solutions Advisory Committee Report 3–4. 2024.
[3] The PIESAC report also proposed developing hydrogen-fired turbines as a source of electric generating capacity, but given the current state of the technology, lack of cohesive federal and statewide hydrogen policies, low energy density, and limited supporting infrastructure and supply chains, IEEFA does not consider hydrogen a viable option and thus did not critique that part of the PIESAC report. For further reading, the answer testimony of David Schlissel in the JTS proceeding (pp. 113-33) provides in-depth analysis on the hydrogen option and its many shortcomings.

the community.[4] But this does not mean ratepayers and taxpayers should be forced to pay for expensive, unproven alternative technologies that will neither be effective nor reliable tools for power generation or decarbonization.

Transitions are admittedly difficult, but the choice facing Colorado is clear. Continuing to build proven time- and cost-certain wind, solar and dispatchable battery storage resources will enable it to meet growing statewide electricity demand reliably and economically. Big bets, funded with ratepayer dollars, on the development of unproven technologies like SMRs and gas with carbon capture, which have high, uncertain price tags and lengthy development times, would likely push billions of dollars of unnecessary costs onto PSCo's customers without providing the reliable electricity needed to power the state's growing economy.

[4] The JTS process is complicated by the fact that PSCo does not provide electric service to the city of Pueblo even though the Comanche power plant is located there and many of the jobs at the plant are held by city and county residents.

Introduction

The body of our report presents an in-depth analysis of two main power replacement options named in the Carbon Free Future Development (CFFD) fund and endorsed by the Pueblo Innovative Energy Solutions Advisory Committee (PIESAC) as part of the ongoing regulatory process in Colorado to plan for the retirement of Unit 3 at the Comanche coal-fired power plant at the end of 2030. We believe those options—small modular reactors (SMRs) and gas with carbon capture—would significantly raise rates for the utility's customers and come with significant technological risks that could slow, or even stop, development efforts. Instead of these costly, risky options, we believe a continuation of ongoing efforts to build additional wind, solar and dispatchable battery storage, potentially combined with co-located clean energy industrial development, is the best, lowest-cost option for the state as a whole, and Pueblo in particular.

We address these options in turn in the remainder of the report.

Nuclear

SMRs: Too Risky, Too Expensive, Too Late

IEEFA has consistently criticized SMR developers and nuclear proponents for trying to wish away the industry's poor track record on reactor cost and construction timelines.[5,6,7] But there is no hiding the huge cost overruns and multi-year construction delays that have been the rule for all nuclear development, and that reality raises valid questions for the current crop of reactor proposals, including potentially in Pueblo.

For example, a 1986 Department of Energy (DOE) study compared the estimated versus actual overnight costs of 75 reactors that started construction between 1967 and 1977. This study found that the actual cost of building these reactors was, on average, triple the cost that had been estimated when construction began.[8] More to the point, the study understated the cost overruns for the reactors built in the United States during this period in two ways. First, it did not include escalation or financing costs. In addition, several of the most expensive reactors built during that period were not included. The same study found that on average, the time to build each of these reactors was 9.7 years, or almost five years longer than had been projected when construction was started.

Little has changed in the years since.

[5] IEEFA. Nuclear Hype Ignores High Cost, Long Timelines. Nov. 18, 2024.
[6] IEEFA. Small Modular Reactors: Still Too Expensive, Too Slow and Too Risky. May 29, 2024.
[7] IEEFA. NuScale's Small Modular Reactor. February 2022.
[8] Energy Information Administration. An Analysis of Nuclear Power Plant Construction Costs.1986.

Four new reactors have been started in the U.S. since 2000. Two, at the Summer Project in South Carolina, were cancelled in 2017 when the estimated cost of the project ballooned from an initial $11 billion to $25 billion. By the time the project was cancelled, the developers had spent $9 billion on the two reactors.

The other two new reactors are at the Vogtle Nuclear Project in Georgia. The estimated cost of these reactors was $14.1 billion at the time construction began in March of 2013 with estimated completion dates of 2016 and 2017. By the time both units were in commercial operation in April 2024, the project had experienced a cost overrun of about $22 billion and a schedule overrun of almost seven years.

Georgia ratepayers are bearing a significant portion of the cost of the Vogtle overruns. For example, ratepayers experienced a total 23.7% rate increase when the two reactors went into service in 2023 and 2024. This means that, on average, ratepayers are paying $18.72 per month, or more than $224 per year—just for the new Vogtle reactors.[9]

Nuclear developers and other supporters of SMRs generally avoid talking about the industry's actual experience with cost and schedule overruns and instead offer a series of presumptive and unproven claims about small modular reactors. These claims include:

- Building multiple copies of the same SMR design will lead to cost declines over time—what is generally called a "positive learning curve."
- Because they will be modular and mass produced in factories, SMRs will be much less expensive to build than existing large reactors and will take substantially less time to build.
- SMRs will be effective tools for addressing climate change and will be able to complement variable renewable resources on the grid.

Before discussing why these claims are wrong, it is important to emphasize that none of the SMR designs currently being marketed in the U.S. have been built and operated. They are, at this point, completely experimental. In fact, only a single design, the GE-Hitachi BWRX-300, has even started construction (at a site in Canada), and that only began in summer 2025. There are no existing factories where the modules for the proposed SMRs are being fabricated.

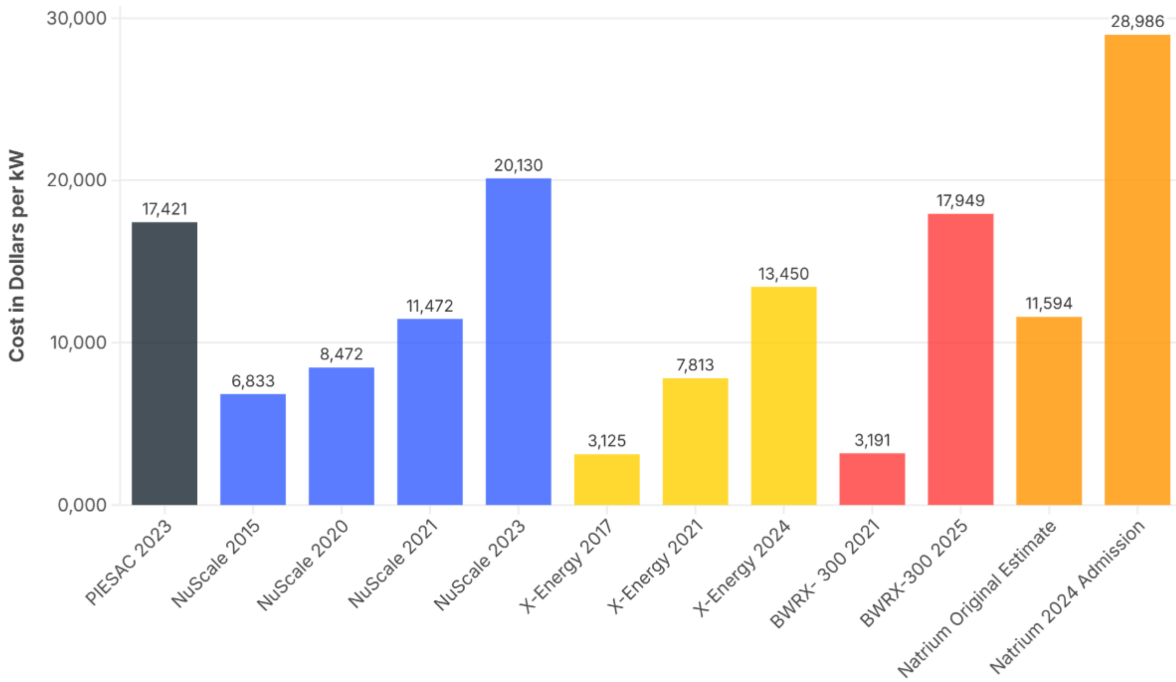
In addition, it is also inaccurate to label these new reactor designs as "small." Although SMRs are generally considered as less than ~350 MW in capacity, several of the reactor designs assume that multiple SMR modules will be installed as part of the same project. For example, NuScale, one of the leading SMR developers, is currently marketing a 77-MW reactor module. If six of these modules were built on the same site, the total project would be 462 MW. If 12 modules were built at the same

[9] Private e-mail correspondence with Patty Durand at Cool Planet Solutions.

site, the total project size would be 924 MW, larger than some operating reactors in the United States. The same would be true if four GE-Hitachi BWRX-300 units were built at the same site.

Finally, even though SMR developers have been zealous in shielding cost information from the public, some estimated cost data has made its way into the public realm as the figure below illustrates. It is clear that SMRs are going to be a costly power source.

Figure 1: Rising Costs of SMRs in the U.S.



Sources: IEEFA, X-Energy statements to Congress and state of Washington, Bill Gates public statements and TVA 2025 IRP

There are several points to emphasize about Figure 1. First, the estimated cost of the SMR NuScale planned to build for the Utah Associated Municipal Power Systems (UAMPS) increased by 138% between 2020 and 2023. The estimated cost of the GE-Hitachi BWRX-300 almost quintupled in just four years after it was initially selected by utilities in Canada in 2021. Similarly, the estimated cost for the X-Energy SMR rose by 72% in just three years.

In fact, concerns about the NuScale SMR's rising construction costs and power prices were precisely why the project was cancelled. The power contract for the project required parties, after a license was granted by the Nuclear Regulatory Commission (NRC), to pay all of the actual costs of the project, even if it was not finished, never provided power, or was damaged or destroyed.[10] Concerns over the project's dramatically rising cost of power and the risk of writing blank checks for

[10] IEEFA. NuScale's Small Modular Reactor. February 2022.

a project for which there was no definite cost factored into UAMPS' failure to secure enough parties to sign contracts for the SMR, and in early 2023, the project was cancelled.

NuScale cited rapidly rising construction commodity prices and high interest rates for the cancellation of its UAMPS project.[11] There is no reason to think that the same higher construction commodity prices—driven by supply chain competition—and high interest rates that led to the cancellation of the NuScale project won't also affect both the costs and the construction times for other SMR designs.

In addition to the dramatic cost increases shown in Figure 1, the leading SMRs currently being marketed in the U.S. also have experienced long delays. For example:

In 2008, NuScale originally told the NRC that an SMR could be producing electricity by 2015-2016. But this was repeatedly pushed back. When NuScale's first proposed SMR was cancelled in 2023, its projected commercial operation date had slipped to 2029 at the earliest.

The initial Xe-100 reactor was first planned to be online by 2027, but this too has been delayed with what is now being called "substantial completion" scheduled for September 2033—with no mention of when the reactor will be in commercial service.

The history of the U.S. nuclear industry clear shows that additional dramatic cost increases and construction delays can be expected after a project is licensed by the NRC and begins construction. In fact, cost increases and schedule delays can be expected at all phases of a reactor project.

Proponents also frequently claim that SMR construction costs and time will go down as more reactors with the same design are built. This is called a positive learning curve. However, this is just an assumption on the part of SMR proponents. There is no actual evidence to support the claim.

The U.S. nuclear industry has not had such a positive learning curve. Indeed, it has had a negative learning curve where the cost of building new reactors has gone up, not down. Even the French nuclear program, which relied on a high degree of standardization in the design of its 58 reactors built between 1974 and 1990, failed to achieve a positive learning curve. Instead, costs continued to increase over time despite the program's design standardization.[12] A peer-group reviewed analysis found that despite its high degree of standardization, the real costs of building reactors in France increased by approximately 5% per year between 1974 and 1984. Costs increased to 6% per year for reactors built between 1984 and 1990.[13]

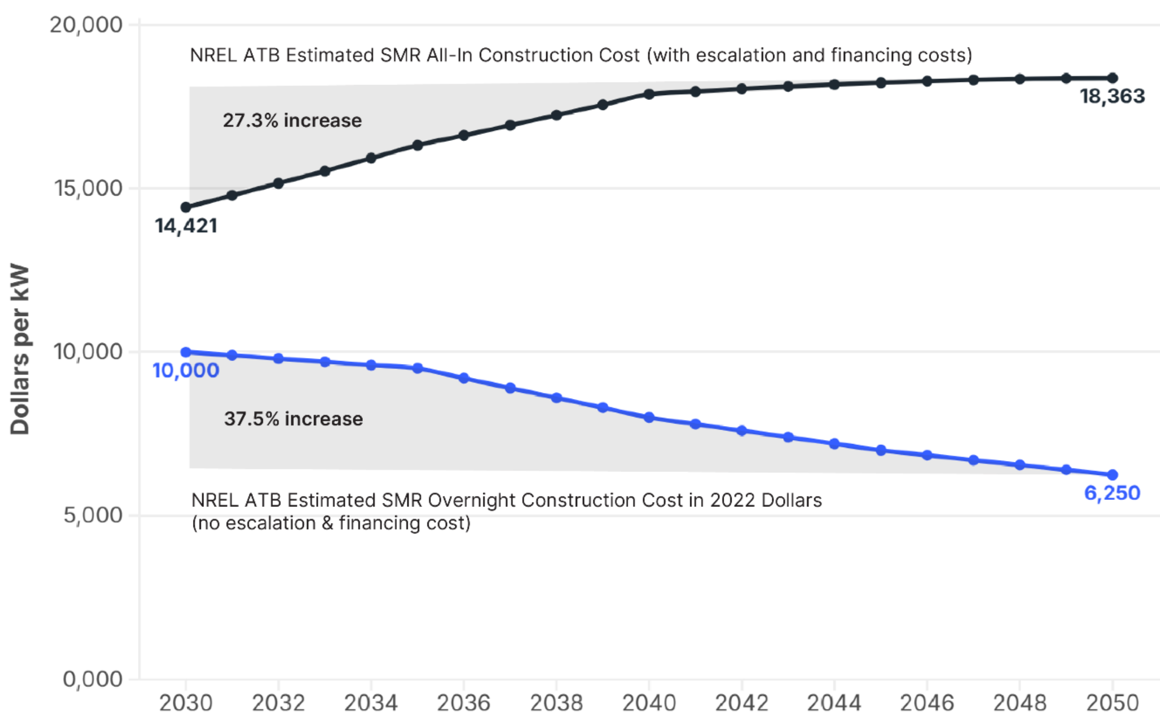
[11] IEEFA. Small Modular Reactors: Still Too Expensive, Too Slow and Too Risky. May 2024.
[12] Energy Policy. The costs of the French nuclear scale-up: A case of negative learning by doing. 2010.
[13] *Ibid.*

When evaluating claims by SMR proponents that building more reactors with the same design will lead to declining costs, it is essential that all costs be included in the calculations. If any critical costs are excluded, the results can be misleading in favor of the SMRs.

There are generally two different ways nuclear costs are evaluated—either by using only the assumed "overnight costs" of a project or its projected "all-in costs." The term overnight costs is the hypothetical total of what it would cost to build a reactor overnight. Therefore, an overnight cost estimate does not include any escalation or financing costs. The term all-in cost is the overnight cost plus escalation and financing costs. It is the estimate of what the reactor project is expected to actually cost to build and gives a better sense of how expensive the cost of power from the reactor will be for ratepayers.

The following example using data from the National Renewable Energy Laboratory's 2024 Annual Technology Baseline (ATB) website shows that even if it is assumed that the overnight cost of an SMR will decline over time, its all-in cost will increase when escalation and financing costs are included. As can be seen, it appears that the levelized cost of an SMR would decline by 37.5% between 2030 and 2050 if only overnight costs are considered. However, the total expense increases by more than 27% during that period when all costs are included.

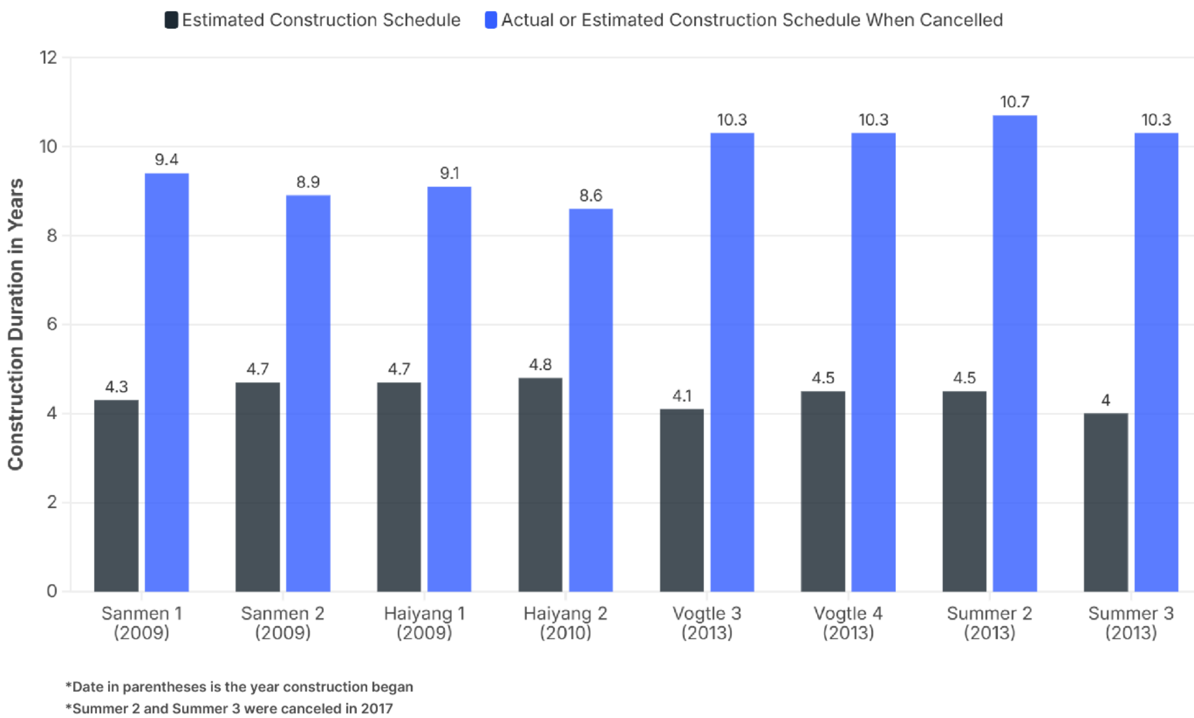
Figure 2: Focusing on Estimated Overnight Costs Instead of All-In Costs is Misleading



Source: 2024 NREL Annual Technology Baseline

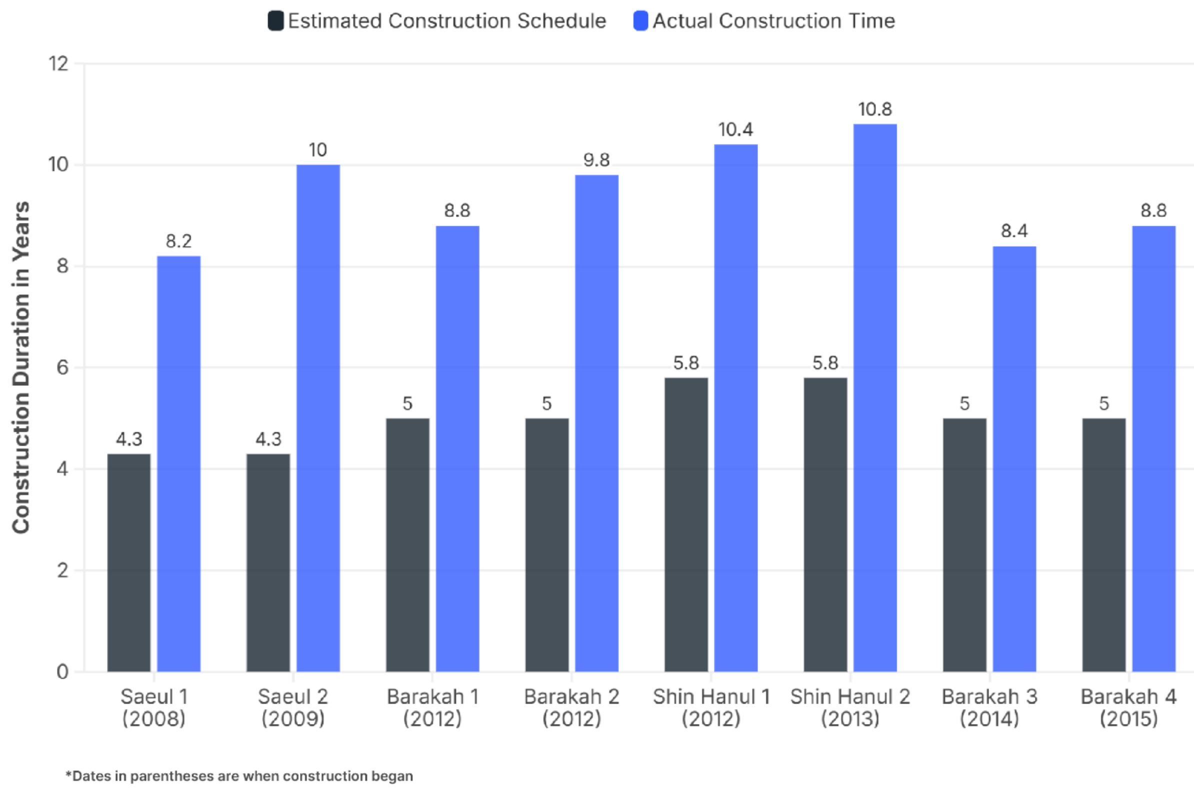
We also have analyzed whether there is any evidence that building numbers of new reactor designs leads to shorter construction times for the later units. As shown in Figures 3 and 4, the answer is "no," based on experience with Westinghouse's two new reactor designs, the AP1000 and the AP1400. The company's results show that there is no positive learning curve for construction time.

Figure 3: AP1000 Construction Times



Source: IAEA PRIS database

Figure 4: AP1400 Construction Times



Source: IAEA PRIS database

There are four key findings from this analysis:

1. Nuclear reactors have not demonstrated a positive learning curve. The time it took to build the most recent reactors in each data point from the figures above was longer than the construction time for the first ones. There was not even a learning curve for the four AP1400 reactors built at the Barakah site in Abu Dhabi with only a year between the start of construction for each reactor.

2. If there had been a positive learning curve, the two Vogtle AP1000 reactors should have been built is less time than the four Chinese reactors that preceded them.

3. All of these reactors were projected to take between four and six years to build, but all experienced significant schedule overruns.

4. All else being equal, a longer construction schedule will mean higher financing costs for a reactor project leading to higher total costs, which in turn will raise the price of power from the facility.

Moreover, any positive learning curve achieved in building SMRs will depend heavily on how many of each design are built. The Organisation for Economic Co-operation and Development (OECD) Nuclear Energy Agency currently estimates that there are 127 SMR designs being considered and marketed worldwide. This makes it highly uncertain how many of each design will be constructed.[14] Too few, and there may not be any cost savings over time, and there may also be no economic justification for modular construction in a factory.

Significantly, the SMRs currently operating in China cost four times more to build than was originally estimated and took 12 years to build, three to four times longer than planned. The cost of the two SMRs in Russia was five times more expensive than projected and took 13 years to build, more than four times longer than planned.[15]

Proponents also claim that because SMRs will be modular and mass produced in factories, they will be much less expensive to build than existing large reactors and will take substantially less time to build. However, there is no evidence to support this claim.

First, none of the companies currently marketing SMRs in the U.S. have factories in which the modules for the reactors will be built. We also haven't seen any evidence that these companies are signaling when or even if their SMR factories will be built and whether they will be built in the U.S. This is a significant risk for anyone proposing to own or buy power from an SMR.

In fact, the DOE has concluded that the U.S. lacks nuclear and megaproject delivery infrastructure:[16]

"Vogtle was the first start-to-finish nuclear construction in 35 years. The dearth of new projects has resulted in a lack of "muscle memory" and a reduction in the nuclear industrial base required to successfully execute nuclear construction projects. There are very few EPC [engineering, procurement, and construction] firms with experience in both nuclear and megaprojects. Much of the nuclear-trained workforce is aging and/or moving into other industries given the lack of new nuclear projects. There are no established developers to integrate and optimize roles and project participants have limited experience with appropriate contract structures." [17]

When Westinghouse was marketing the AP1000 reactor design that would ultimately be built at Vogtle and started at the Summer Project in South Carolina, it cited almost exactly the same claims as SMR proponents are making today: There would be significant benefits from the reactors' new design and from the use "of modern modular construction techniques."[18]

However, the projects ran into serious problems with both modular construction and the use of factory-built modules, which contributed to the $22 billion cost overrun and multi-year construction

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[14] NEA. Small Modular Reactor Dashboard. February 14, 2025.
[15] Answer Testimony of David A. Schlissel in Colorado PUC Proceeding No. 24A-0442E, p. 30-31.
[16] A megaproject is a large project generally expected to cost more than $1 billion.
[17] U.S. Department of Energy. Pathways to Commercial Liftoff: Advanced Nuclear. p. 71. 2024.
[18] Power Magazine. Plant Vogtle Leads the Next Nuclear Generation. November 1, 2009.

delays at Vogtle and the $14 billion increase in Summer's estimated construction cost.[19] In fact, it would be a severe understatement to say that modular construction and the use of factory-built modules did not work as well at either project as Westinghouse had claimed in its marketing materials.

These problems were summed up in a 2017 Reuters analysis completed after Westinghouse filed for bankruptcy protection:

"[T]he source of the biggest delays can be traced to the AP1000's innovative design and the challenges created by the untested approach to manufacturing and building reactors, according to more than a dozen interviews with former and current Westinghouse employees, nuclear experts and regulators.

"Unlike previous reactors, the AP1000 would be built from prefabricated parts; specialized workers at a factory would churn out sections of the reactor that would be shipped to the construction site for assembly. Westinghouse said in marketing materials this method would standardize nuclear plant construction." [20]

Despite the financial disasters at both Vogtle and Summer, the nuclear industry and its supporters are making the same claims about the benefits of modular construction using factory-built modules as Westinghouse and others made before those projects began.

There are additional risks from long SMR construction times beyond just higher project capital costs. The longer construction takes, the more difficult it becomes to change course if costs rise faster than expected, expected demand does not materialize, or the costs of alternatives continue to decline. This dynamic is what led to the cancellation of more than 100 proposed coal plants from 2005 to 2015. Expected demand did not develop, costs went up, and the cost of natural gas cratered because of fracking. Something similar could occur with SMRs if the currently projected demand growth from data centers and artificial intelligence does not materialize. It would be far more prudent to build new capacity that can be added without long lead times, like solar and dispatchable battery storage facilities, so utilities and ratepayers aren't trapped in projects that are increasingly expensive and/or not needed.

Economies of scale require mass production. Indeed, that is one of the upsides nuclear proponents promote, but there are also potential problems with such scaling up. Building many copies of the same SMR design opens the door to systemic flaws affecting multiple numbers of the same standardized SMR designs. This has been referred to as the "Boeing Problem" by Arjun Makhijani of the Institute for Energy and Environmental Research because of problems that affected the plane manufacturer's 787 Dreamliners and 737 Max jetliners. The same problem could arise with mass-produced reactors. An unexpected and unidentified design flaw discovered in a key component of a

[19] For example, see the Answer Testimony of David A. Schlissel in Colorado PUC Proceeding No. 24A-0442E at page 43, line 11, to page 47, line 15.
[20] Reuters. How two cutting edge U.S. nuclear projects bankrupted Westinghouse. May 2, 2017.

highly standardized SMR could lead to extended and expensive outages, repairs, and design changes.

This is not simply a hypothetical risk. Problems have cropped up during the operation of reactors around the world due to material choices and design decisions made before plants were even built. For example, according to the World Nuclear Association, operators have been forced to replace steam generators at more than 110 pressurized water reactors (PWRs)—more than half of which have been in the United States—since 1980.[21] Similarly, cracking in safety-related piping in boiling water reactors (BWRs) led to extensive and expensive piping replacements in 12 U.S. BWRs.[22] Detailed inspections of key piping systems and changes to the water chemistry used in the plants were made at essentially all BWRs in the United States. The efforts required to fix these systemic problems were both time-consuming and expensive.

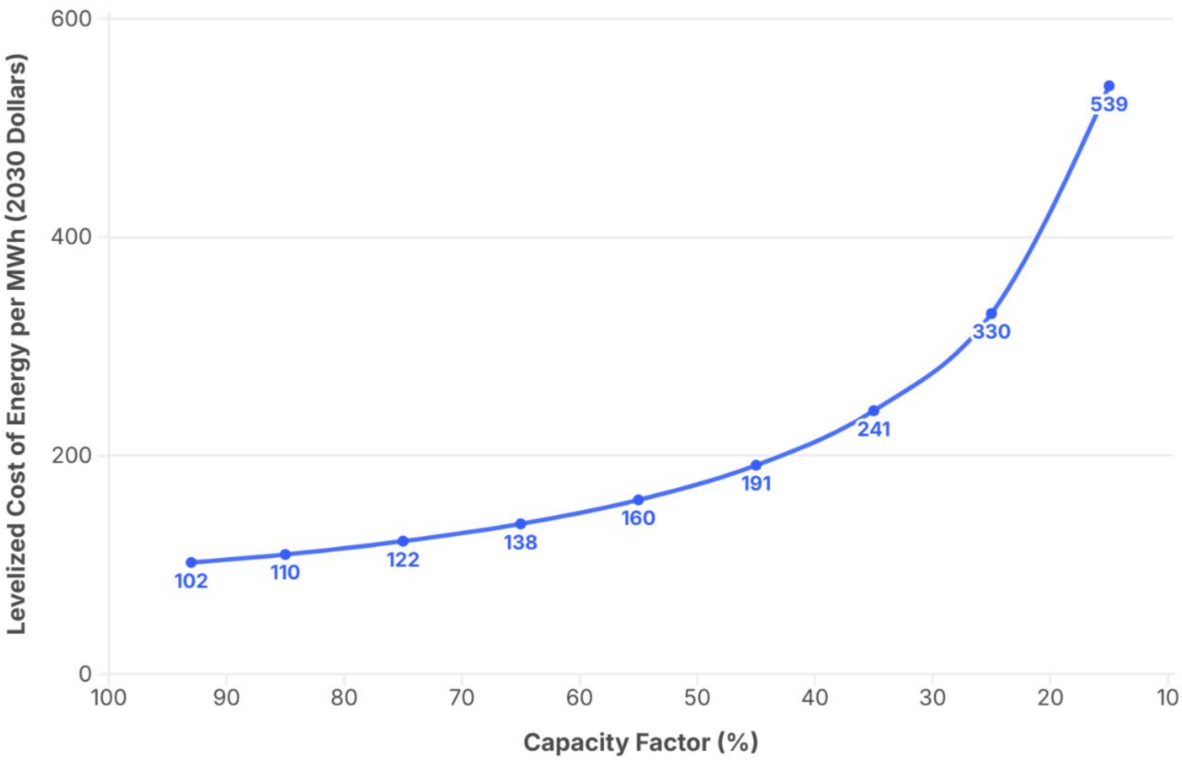
New SMRs design and assembly may not face the same issues, but the point remains: Any problem with an SMR design that is mass-produced might have serious cost and operational repercussions at other SMRs with the same or a similar standardized design.

These cost and construction concerns also play into another problem for SMRs: They will not be compatible with renewable energy resources. Their projected high cost will force operators to run them as much as possible, aiming for capacity factors above 90%. This will turn SMRs into competitors of renewable resources and potentially force fuel-cost-free wind and solar generators to curtail production.

To be a true complement for renewables, SMRs would need to cycle up and down in response to demand on the grid and the availability of wind and solar resources. While developers say their new reactors will be able to ramp, the reality is SMRs cannot both achieve high capacity factors and operate flexibly, in a load-following manner, by ramping up and down. Because most SMR costs will be fixed capital charges, reducing a unit's capacity factor via cycling or ramping will significantly raise its average cost of power and reduce the SMR's profitability.

21 World Nuclear Association. Nuclear Power Reactors. Last visited April 17, 2025.
22 U.S. Nuclear Regulatory Commission. Pipe Cracking in U.S. BWRs: A Regulatory History. 2000.

Figure 5: SMR Power Costs Climb As Capacity Factor Falls



Source: NREL 2024 Annual Technology Baseline

Using the spreadsheet developed by the National Renewable Energy Laboratory (NREL) available on its 2024 ATB website, we have compared the estimated levelized cost of energy (LCOE) from an SMR with the costs of power from wind, solar and solar+storage resources.

Due to the significant uncertainties about the costs and schedule for SMRs, as outlined above, we assumed a range of potential LCOEs. For both the high and the low end of this range, we assumed that a new SMR in a community like Pueblo with a former fossil fuel generating facility would be eligible for the full 50% investment tax credit (ITC) authorized by the Inflation Reduction Act.

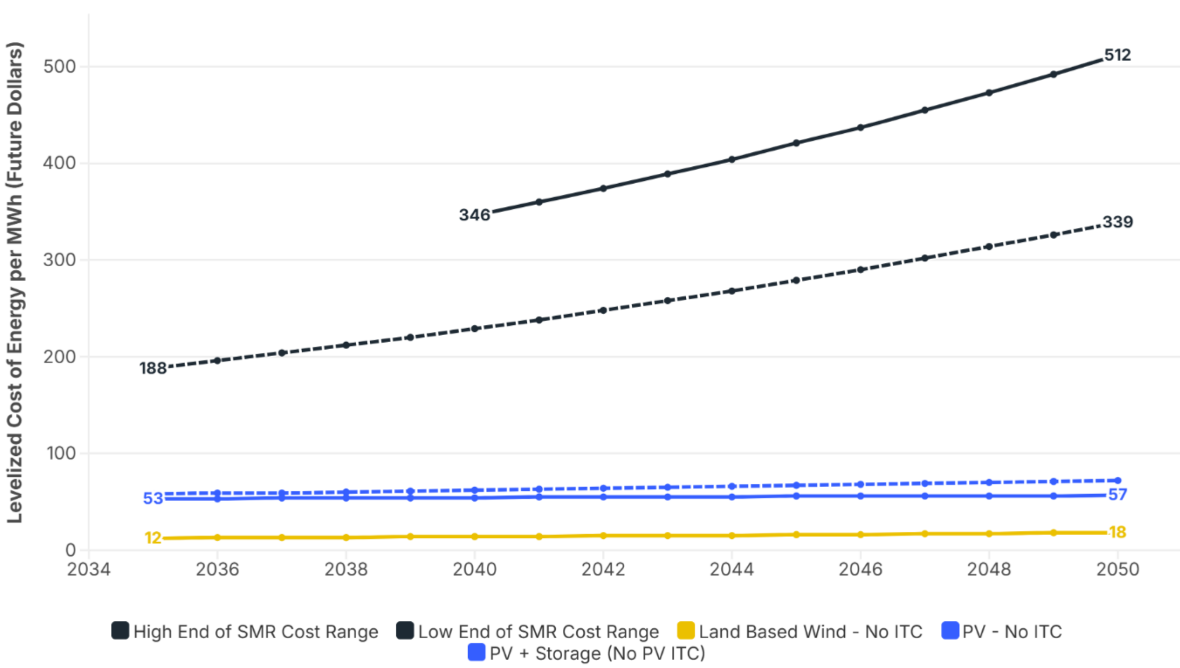
For the low end of the SMR cost range, we used the Tennessee Valley Authority's (TVA) recent estimate that the overnight cost of an SMR would be $17,949 per kilowatt (kW) in 2024 dollars. Because the NREL spreadsheet uses costs in year 2022 dollars, we adjusted TVA's estimated SMR cost down to $17,000 per kW in 2022 dollars. For the high end of the SMR cost range, we increased the estimated overnight cost by 50% to $25,500, although it is possible that this is too low.

We also used a 4% annual escalation rate based on the Handy-Whitman Index of Public Utility Costs for a nuclear production plant. A 4% annual escalation rate is consistent with the actual experience for nuclear plants for both the periods 2000-23 and 2010-23. It also reflects the significantly higher construction design, commodity and labor costs that we anticipate would be experienced if the large nuclear buildout currently being proposed happens.

Pursuant to legislation passed by Congress in July 2025, we assumed that there will be no ITC or production tax credits (PTC) for wind or solar that comes online after 2030, although new storage capacity would still be eligible for the ITC. We made this assumption even though we believe that the federal policies on tax credits wind and storage may well be reversed in coming years.

The results of our analysis are shown in Figure 6 below. As can be seen, even without the tax credits, electricity from renewable resources would be much less expensive than that from SMRs.

Figure 6: Comparative Costs of Power From an SMR and Renewable Resources



Source: Analysis of data and assumptions from NREL's 2024 technology baseline, TVA's 2025 IRP, DOE's September 2024 Pathway to Commercial Liftoff: Advanced Nuclear, and the Handy-Whitman Index of Public Utility Construction Costs

Taken together, the already high costs for SMRs, coupled with uncertain construction lead times and potential additional costs make the technology a huge risk for Colorado. Instead, state utility regulators should push for the continued buildout of existing quick-to-market and cost-effective renewables and dispatchable battery storage, plus new transmission as needed.

The many concerns about new nuclear reactors (both SMRs and large traditional units) are summed up nicely by Donald Grace, who has more than 50 years of experience in nuclear and fossil power plants and served as the Georgia Public Service Commission's Plant Vogtle construction monitor from 2017 to 2024. He concluded that:

"More than 15 years after the Plant Vogtle expansion project first was licensed, the enormous cost overruns, the prolonged construction timeline, and the significant burden on ratepayers in Georgia reveal that **nuclear reactor technologies cannot be relied on as a cost-effective solution to our growing energy needs, as the evidence points to more affordable, faster, and readily available near-term alternatives."** [23] [emphasis added]

Gas and Carbon Capture

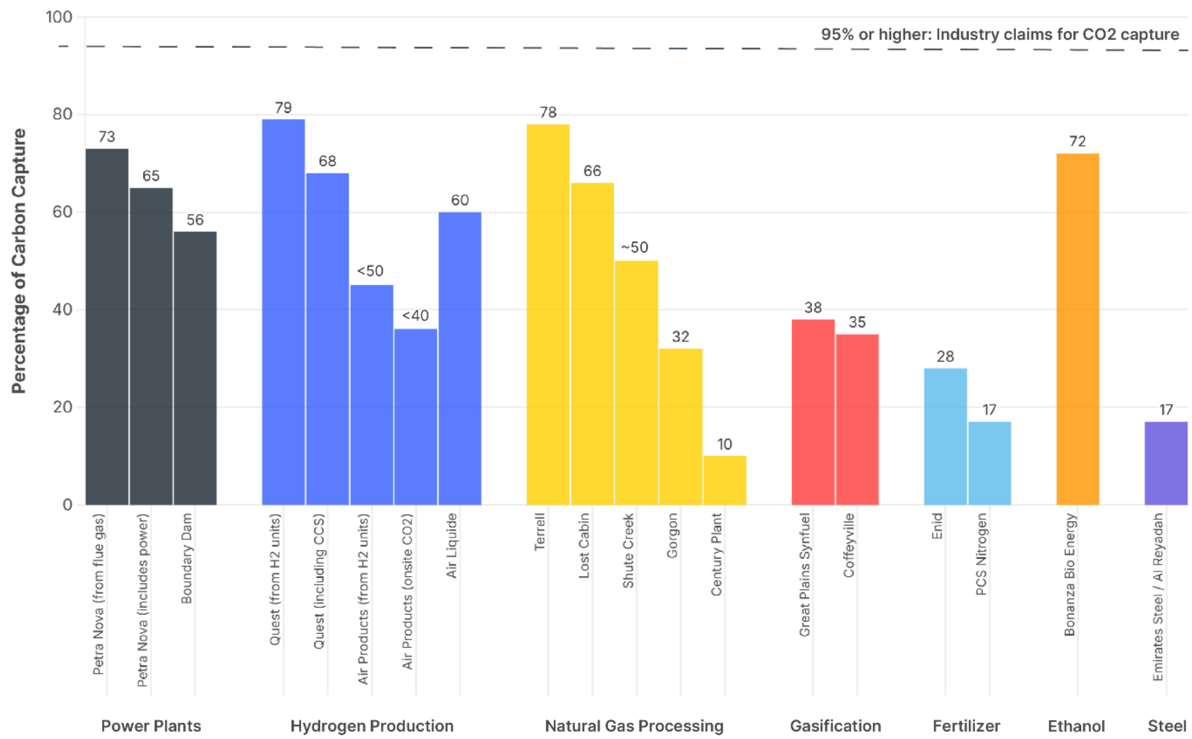
An Unproven and Expensive Combination

Carbon capture and storage (CCS) proponents tout the technology's ability to capture extremely high levels of carbon dioxide (CO_2), with claims regularly running to 95% of a plant's total emissions. The 2023 PIESAC report even claimed that a carbon capture facility could be built that would capture 100% of the CO_2 from a gas plant although it did acknowledge that such a facility could not be in service by 2031.[24] However, IEEFA research has shown conclusively that such claims do not mesh with the reality of existing projects and that carbon capture fails to perform even close to its advertised levels.

Although owners of existing carbon capture projects are reluctant to reveal their actual CO_2 capture rates or the underlying data, it is possible to calculate reasonable estimates for about half of the CCS projects operating in the world as of the end of 2023. The following figure shows that none of the projects for which there is available data have achieved CO_2 capture rates anywhere close to the >95% that the industry and supporters typically claim for proposed projects.

[23] Power Magazine. What Was Learned from Building New Nuclear Reactors? April 1, 2025.
[24] Colorado Public Utilities Commission. Proceeding No. 24A-0442E, Hearing Exhibit 101, Attachment JWI-4, p. 24.

Figure 7: Real World CCS Operating Performance



Sources: IEEFA, Shell Quest Project annual reports, Boundary Dam 3 status reports, U.S. EPA FLIGHT database, NRG; Emirates Steel, and DOE

Although there are pilot projects on several coal-fired power plants and at other industrial facilities, CO_2 capture has never been demonstrated on a commercial-scale gas-fired power plant, raising substantial uncertainty about its cost and efficacy. The one project where CO_2 was captured from an operating gas-fired plant only treated a slipstream totaling 7% of the facility's flue gases. Little operating information is available regarding the project, which was located in Massachusetts and ceased operations two decades ago. But, the Edison Electric Institute (EEI), the trade group representing the nation's investor-owned utilities, sharply criticized the Environmental Protection Agency's reliance on the plant—what it called "a dismantled project in Massachusetts"—in its finding that CCS has been adequately demonstrated for use on new gas-fired generation units.[25] EEI also noted that EPA's technical report on CCS had downplayed several relevant facts related to this project:

"This project did not capture 90 percent of the flue gas. In addition, the CO_2 did not have to be transported via a pipeline and it did not need to be stored underground. In short, EPA relies on a facility that operated a relatively small (e.g., less than 10 percent of facility output) slipstream project

[25] EEI. Comments on EPA's Proposed Clean Air Section 111 Rules for Power Plants, Docket No. EPA-HQ-OAR-2023-0072. August 9, 2023.

to capture CO_2 for use at an adjacent facility, and which was entirely dismantled 18 years before the current proposal as its principal example for demonstration within the industry. This is not sufficient to conclude that 90 percent capture at natural gas-based units is adequately demonstrated." [26]

On top of these significant questions regarding its effectiveness, gas-fired CCS is certain to be expensive given the significantly lower concentration of CO_2 in the fuel gas compared to coal-fired generation units. This point was driven home by Justin Tomljanovic, Xcel's senior vice president of utility finance and corporate development, in his testimony on the Pueblo Just Transition case:

"… The concentration of CO_2 in the [flue gases from an industrial or power facility] determines the cost, method, and technology that is used. Lower concentrations of CO_2 result in higher costs which makes direct air capture the most expensive. Carbon capture for power plants was developed specifically for coal-fired plants which have relatively high CO_2 concentrations, and the technology dates back almost fifty years. **Carbon capture for natural gas fired power plants has not been widely deployed because the concentrations of CO_2 can be one fourth that of coal plants which increases cost challenges.**[27] [emphasis added]

Admittedly, some small-scale CO_2 tests have shown promise for use on gas-fired power plants. The Technology Centre Mongstad in Norway, for example, has the capability to capture roughly 300 metric tons of CO_2 a day (less than 200,000 metric tons per year) from an adjoining refinery and gas-fired power plant.[28] However, this pales in comparison to emissions from commercial-size gas-fired power plants. For example, the 485 MW Hannibal combined cycle plant, a project in Ohio that is about the same size as the planned 500 MW of replacement capacity considered in the PIESAC report, emitted more than 1.4 million tons of CO_2 in both 2023 and 2024.

Scaling up to successfully capture CO_2 emissions at those significantly higher levels will be challenging, and using small-scale tests as conclusive evidence that it can be done is disingenuous at best. It is also a lesson that industry and CCS supporters should have learned from past failures.

Southern Company's Kemper Integrated Gasification Combined Cycle (IGCC) project is a prime example of a technology that appeared ready for commercial development when tested at small scale but failed to operate reliably when applied at commercial scale.

As initially proposed, Kemper was going to use a new technology (Transport Integrated Gasification or TRIG™) to gasify low-quality lignite coal in Mississippi, with the goal of capturing 65% of the CO_2 before the gasified coal was burned at the plant.[29] According to Southern Company, TRIG™ had been successfully tested at the U.S. National Carbon Capture Center in Alabama. However, when the technology was installed at the commercial-scale Kemper plant, significant and unsolvable problems

[26] Ibid.
[27] Justin M. Tomljanovic, Hearing Exhibit 103 in Colorado PUC Proceeding No. 24A-0442E, p. 36, lines 4-13.
[28] Press Release, Mitsubishi Heavy Industries, Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New "KS-21TM" Solvent for Carbon Capture (Oct. 19, 2021), https://www.mhi.com/news/211019.html.
[29] Southern Company, 2017 Carbon Disclosure Report. 2017.

were revealed that prevented the coal gasification process from operating reliably. As a result, the plan to burn gasified coal was scrapped, but not before the company spent $7.5 billion[30] on the project, turning the 734 MW Kemper facility (since renamed Plant Ratcliffe) into what is now almost certainly the world's most expensive natural gas-burning combined cycle power plant. It does not use gasified coal, and none of the CO_2 it emits is captured.

This painful and expensive experience explains Southern Company's warning that new capture technologies must be demonstrated at commercial scale before being deemed capable of capturing 90% or more of a gas-burning plant's CO_2:

"CO_2 capture on a small scale has been happening for many years in the petroleum, ethanol, and industrial chemical industries. While deployed in these industrial sectors for commercial uses, the technology has not been deployed to date at commercial scale as an environmental control technology, where reliability and consistent performance are paramount requirements to ensure compliance with regulatory standards and permit conditions." [31]

Similar concerns were raised by American Electric Power (AEP), a multi-state utility that has investigated CCS on coal-fired units and operates a significant amount of gas-fired generation capacity. In its comments on EPA's proposed CO_2 capture requirement for new gas capacity, the utility said:[32]

- "CCS remains many years from being proven to be a technically feasible, adequately demonstrated, and commercially viable solution for reducing CO_2 emissions."
- "All aspects of CCS (capture, transport, and geologic storage) must overcome significant technical, financial, regulatory, legal, and practical barriers before the technology can be considered as the [best system of emissions reduction]."
- "The wide disparity in the cost estimates of current efforts to develop CCS is indicative that CCS has not been adequately demonstrated. [C]urrent estimates of CCS costs continue to evolve and must factor in all aspects of the technology: capture, transport, storage, including long-term monitoring and liabilities of storage."
- "Significant consideration must be given to issues related to CO_2 pipeline development which pose several schedule, cost, and regulatory uncertainties that can impact the feasibility of any CCS project."

One of the capture technologies now being proposed for new gas-fired plants may prove capable of capturing more than 90% of the CO_2 that would otherwise be emitted. But that success cannot be taken for granted based solely on the results of small-scale testing results. And even if the

[30] Utility Dive. Cost Settlement for Failed $7.5B Kemper 'Clean Coal' Project Heads to Finish Line. Jan. 24, 2018.
[31] Southern Company. Comments on EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-Fired Power Plants, Docket No. EPA-HQ-OAR-2022-0723. December 21, 2022, p. 7.
[32] AEP. Comments on EPA's Non-Rulemaking Docket on Reducing Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Stationary Combustion Turbines, Docket No. EPA-HQ-OAR-2024-0135. May 28, 2024, p. 4.

technology does prove viable, there are other hurdles that must be resolved, including geographical constraints, access to water, permitting for storage facilities, parasitic load, and cost, before CCS can be widely commercialized.

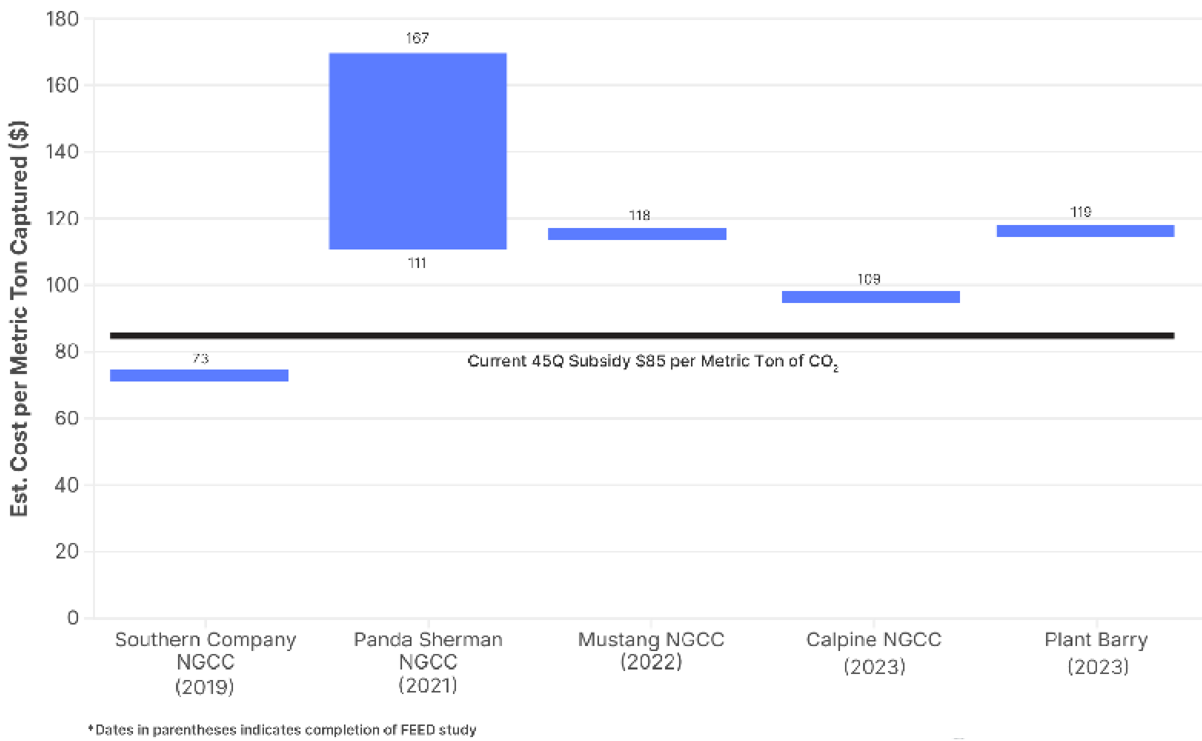
Of these, cost is the key concern.

Adding CCS will raise the cost of power in several ways. First, there is the recovery of the additional investment in the CCS facility and its annual operating and maintenance (O&M) costs. Second, the plant's heat rate and its internal auxiliary loads will both be higher. For example, a 2023 DOE study showed that a gas plant's heat rate would rise by about 12% and its auxiliary loads would grow by about 35 MW to 45 MW due to a portion of the output being consumed to run the carbon capture equipment.[33] As a result, the plant would end up burning more gas and having less electricity to sell. The combination would adversely affect the cost of the power from a plant and its financial viability, even if it were collecting federal 45Q subsidies equal in value to its cost of capturing CO_2.[34]

That likelihood is remote. Federal financial support for CO_2 capture has increased significantly, with the current level now at $85 per metric ton, whether it is sequestered or used for enhanced oil recovery (EOR). But even as that support has risen, estimated capture costs have been climbing as well. Recent front-end engineering design (FEED) studies funded by DOE indicate that the cost of adding CCS to existing power plants and industrial facilities would be significantly higher than the existing 45Q credit.[35]

[33] National Energy Technology Laboratory. Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. 2022.
[34] Under current federal law, parties that capture CO_2 from power or industrial facilities receive an $85 tax credit for each metric ton of CO_2 they capture. These are commonly called 45Q credits or subsidies because they are in Section 45Q of the tax law.
[35] See: U.S. Department of Energy. Carbon Capture Demonstration Projects Program Front-End Engineering Design (FEED) Studies Selections for Award Negotiations. Last visited April 17, 2025.

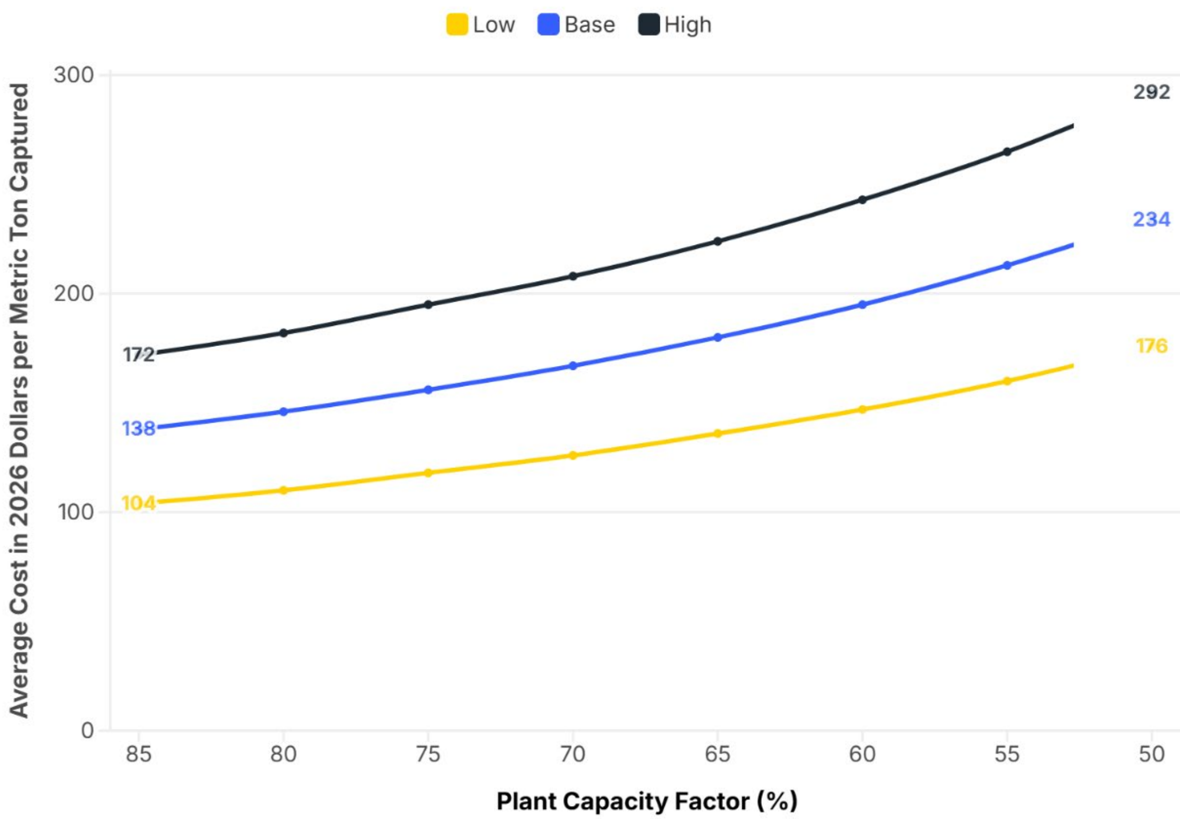
Figure 8: FEED Study Cost Estimates for Gas-Fired CCS Retrofits



Source: IEEFA analysis of DOE-funded CCS front end engineering design studies

These FEED study estimates also assume the carbon capture units will operate at a high level, generally between 85% and 95% of capacity. If they do not, costs would rise significantly, as shown in the following graphic.

Figure 9: Impact on Capture Cost of Lower Unit Performance



Source: FEED study for a CCS retrofit at a gas-fired combined cycle power plant

Estimated CCS capture costs also are going up due to the same factors that have led to the increases in estimated SMR costs discussed previously. CCS capture costs have increased due to competition for design and construction resources—including labor and commodities like concrete, steel, and copper—that are needed to build power plants and other large construction projects. In particular, there has been a significant increase in gas turbine prices in the past few years.

Data tracked by IEEFA shows that these costs have climbed by at least 50% in the past couple of years, with no indication of any slowdown and increasing delays in projected completion dates. A proposal from LG&E-KU in Kentucky is indicative of these cost pressures. The utility is now building a 660-MW combined cycle gas turbine (CCGT) that is due to come online in 2027; its total cost is currently estimated at $913 million. Earlier this year, the utility submitted a plan to Kentucky regulators to build two additional CCGT units, both 645MW in size; the projected cost for those facilities, due to come online in 2030 and 2031, is $1.38 billion and $1.41 billion.

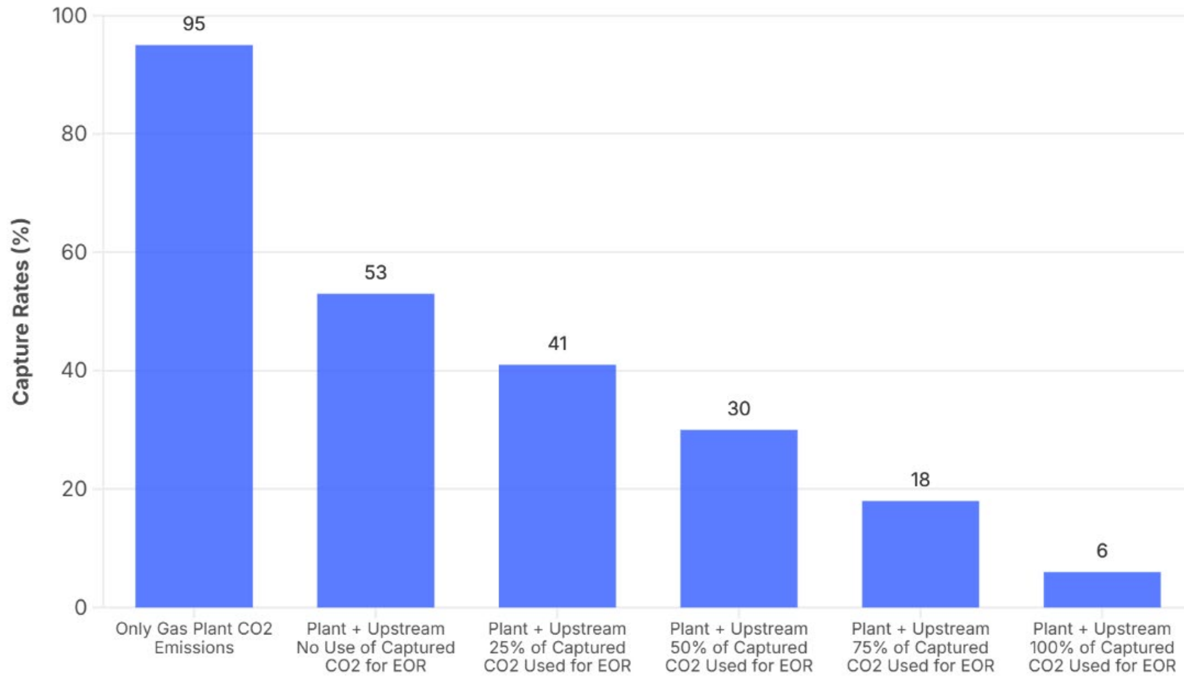
The PIESAC report assumed the entire project, a 500 MW CCGT coupled with CCS, would cost $1.345 billion. That estimate is woefully out of date, with no certainty that even the power generation equipment could be purchased for that price in the current market. Even assuming that is possible, the cost of the equipment and components for CCS would easily bring the total cost of building a gas plant with carbon capture in Pueblo to more than $2 billion and likely even higher since CCS component pricing has risen.

For example, the estimated cost of Project Tundra, which would add CO_2 capture equipment to the Milton R. Young coal plant in North Dakota, almost doubled in just three years—from roughly $1 billion in 2020 to about $1.94 billion in 2023.[36] Part of the estimated cost increase appears to be the result of design changes, but a doubling in the project's projected price tag before construction has even started should, and does, cause concern.

And even assuming these barriers are overcome, there would still be significant greenhouse gas emissions associated with gas-fired power generation, undercutting the rationale for CCS in the first place. These emissions would come from: (1) upstream methane leakage between the production well and the power plant; (2) leakage of the captured CO_2 between the plant and the site where it will be used or stored underground; and (3) any emissions from the use of captured CO_2, especially if it used for EOR. With these emissions, the project's effective lifecycle CO_2 equivalent (CO_2e) capture rate would be substantially lower than that for the power plant alone. The impact of analyzing the full lifecycle emissions from gas-fired power plants, even with high capture rates at the generation site, is shown in the graphic below. These lifecycle emissions were calculated by IEEFA using an assumed upstream leakage rate of 2.5 percent and an estimate that using CO_2 for EOR only yields a net reduction of 0.11 tons in the lifecycle CO_2 emissions from the plant.[37]

[36] Energy & Policy Institute. Department of Energy analysis says coal carbon capture project would emit more greenhouse gases than it stores. September 14, 2023.
[37] Further information on these calculations can be found in the Answer Testimony of David A. Schlissel. Colorado PUC Proceeding No. 24A-0442E, pp. 83-94.

Figure 10: Lifecycle Capture Rates From Claimed 95% Capture Plant



Source: Schlissel answer testimony

The takeaway is clear. CCS is an unproven technology for gas-fired power generation. Its performance is uncertain and its costs are unknown. It will not help Pueblo transition to a cleaner future, but it almost certainly will lead to significant increases in electricity costs for Public Service of Colorado ratepayers saddled with underwriting the project. Gas with CCS is a lose-lose proposition for Colorado.

Real Solutions

In contrast to the expense and uncertainty of SMRs and CCS, renewables are ready now, can be built quickly, are cost competitive, and, importantly, offer price certainty to corporate executives. Paired with short- and long-term dispatchable battery and thermal storage, issues around variability are fading as a concern. And new models incorporating industrial projects that can take advantage of clean energy, storage and flexible load profiles can provide economic diversification that traditional power plants like coal, nuclear and gas cannot.

There is no longer any doubt about the cost superiority of renewables and storage over experimental SMR and CCS technologies—or all generating sources, for that matter. For example, as shown in Figure 6 above, even without the wind and solar subsidies that were in the 2022 Inflation Reduction Act, the cost of power from renewables would be much less expensive than that from either the SMR or CCS options.

We are not only ones to see that renewable alternatives would be the most economic option. For example, in its latest industry-standard apples-to-apples cost comparison of generating resources, consulting firm Lazard determined that "on an unsubsidized $/MWh basis, renewable energy ***remains the most cost-competitive form of generation***" (emphasis added).[38]

Building out renewables and storage comes with another important financial benefit that nuclear and combustion generating resources lack. Once up and running, wind and solar have no fuel costs. Fuel-dependent resources such as nuclear and gas rely on commodities that are subject to the laws of supply and demand.

Gas is especially subject to volatile price swings, sometimes driven by market considerations and sometimes by disruptions such as severe weather that can lead to dramatic spikes in pricing as supplies become constrained. In February 2021, for example, Winter Storm Uri wrought havoc on energy costs nationwide with record-breaking demand fueled by extreme cold weather mixed with supply shortages that were caused by production shortages and disruptions due to freezing wellheads and pipelines. Natural gas prices soared to record highs, with some regions experiencing price spikes 100 to 300 times more than normal.[39]

While not as affected by severe weather, nuclear fuel nonetheless has also seen market swings based on supply and demand, as well as geopolitical considerations.[40] Renewable resources like wind and solar have no fuel costs and very low maintenance costs, so their power prices are stable. Also, the increasing penetration of battery storage capacity is quickly dispensing with historic criticisms of intermittency, making "the sun doesn't always shine, and the wind doesn't always blow" statements of the past.

Contrary to rhetoric from fossil fuel proponents, this firming of renewable resources can provide the 24/7 reliability and price stability that is attractive to major power users that want constant power, whether AI data centers or large industrial firms. An announcement earlier this year by Rio Tinto, one of the world's leading aluminum producers, shows what is possible. According to the company, it will use solar and battery storage to decarbonize one of its large aluminum smelting facilities in Queensland, Australia.

In a LinkedIn post at the time of the announcement, the head of Rio Tinto's aluminum operations, Jérôme Pécresse, said the company's smelters "can technically work on any source, provided they are guaranteed to get uninterruptible power supply, as they cannot stop production."[41] In the past, he added, that power has been coal-fired, but it doesn't have to be: "There is no reason why, in

[38] Lazard. Levelized Cost of Energy+: Version 18.0. June 2025.
[39] Kansas Corporation Commission. Consumer Alert. August 22, 2023.
[40] World Nuclear Association. Uranium Markets. August 2024.
[41] Renew Economy. Solar battery deal for giant smelter is a stunning game-changer for Australian energy. March 14, 2025.

some places, it cannot be achieved via a mix of intermittent renewables, provided that this mix is 'firmed' via batteries and other sources."[42]

Renewables also provide far more price certainty compared to resources reliant on fuels like gas that are subject to commodity price swings. The importance of price certainty was underscored recently by Henry Shields, vice president for research and analytics for MGM Resorts International. MGM is the largest employer in Nevada and has become a strong proponent of solar. Betting on solar, said Shields, "gave us control of what we're going to pay for energy over the next few decades."[43]

This point is one that those involved with economic development in Pueblo should take to heart. Having price certainty and dependable development timelines allows businesses to plan, something that would never be possible with SMRs or gas with carbon capture.

The flexibility of renewables and energy storage is transforming the historic utility model of energy generation from a one-way resource that simply sends power onto the grid to a dynamic and integrated two-way energy resource that can put out electricity when demand is high and absorb it via storage when demand is low and the economics are favorable. Think tank Energy Innovation has developed a conceptual framework for this new model—what it calls an "energy park"—and applied it to the Comanche coal plant in Pueblo.[44] Energy Innovation's Pueblo energy park would have three important and interlocking pieces: 1) a buildout of wind, solar and short-term storage capacity in the city and across southeastern Colorado; 2) an accompanying addition of both short- and long-term (thermal) battery storage at the site of or near the coal plant; and 3) co-location on site or nearby with industry that can take advantage of the thermal storage capacity.

The energy park concept would benefit all parties. The utility would be able to capture the favorable economics of storing surplus wind and solar production rather than having to sell it at below-market prices or curtail production and then sell it when market prices are more favorable. Consumers would benefit from the buildout of new renewables, which would put downward pressure on electric rates. Businesses located in the park would have access to lower-cost electricity by essentially serving as a battery, absorbing generation during periods of peak output by raising their demand and giving that demand back to the utility during system-wide peak demand periods.

The modeling done by Energy Innovation shows that the energy park would generate an estimated $40 million or more in annual property taxes for Pueblo County and create more than 350 permanent jobs directly, plus additional jobs at co-located industrial facilities. As Energy Innovation notes, with the ability for wind, solar and energy storage to be built quickly, the jobs and tax revenue could begin flowing even before the 2030 retirement date of the plant—long before they would with nuclear or gas with carbon capture plants.

[42] Ibid.
[43] The New York Times. Nevada is all in on Solar Power. June 24, 2025.
[44] Energy Innovation. Flexible, Clean Industry and Sustainable Energy Power Strong Economies: A case study in Pueblo, Colorado. April 2025.

Conclusion

The choice facing Colorado is clear. It can chase unproven options such as SMRs and gas with carbon capture that are going to be expensive and have uncertain commercialization timelines. Or it can begin building cost-competitive and available wind, solar and dispatchable battery storage resources now, and continue building them over time as demand dictates.

In addition to the cost and time certainty associated with renewables and storage, that approach would give Public Service of Colorado valuable flexibility in its resource planning efforts. This approach would enable it to avoid being trapped with stranded assets in expensive nuclear and gas investments if dramatic increases in future demand for loads from new data centers do not materialize or materialize differently than expected. At the same time, renewable generation and storage resources could be added in a relatively shorter period if demand grows at a greater rate than now expected. This flexibility is vital in today's dynamic energy transition.

This flexible, renewable-based approach would also benefit Pueblo. The cost-competitive renewable power, brought online on time-certain development intervals, would enable businesses to build and expand throughout the region. Coupling these resources and operating them flexibly, as in Energy Innovation's proposal, would further enhance the benefits, both for Pueblo and the utility, offering grid reliability and affordability in a renewables heavy mix, while providing significant local economic benefits.

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

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