**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

PROCEEDING NO. 24A-0442E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2024 JUST TRANSITION SOLICITATION.

Hearing Exhibit 1701

Answer Testimony of David A. Schlissel

On behalf of the Environmental Justice Coalition

April 18, 2025

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I. Introduction

Q. Please state your name, occupation, and business address.

A. My name is David A. Schlissel. I work as a consultant on energy and environmental issues. My business address is Schlissel Technical Consulting, 194 Westminster Avenue, Arlington, Massachusetts 02474.

Q. On whose behalf are you testifying?

A. I am submitting this Answer Testimony on behalf of the Environmental Justice Coalition (the "EJC" or the "Coalition"). The Environmental Justice Coalition in this case is comprised of GreenLatinos; GRID Alternatives; NAACP State Conference CO-MT-WY, Pueblo Branch; Roots to Resilience; and Vote Solar.

Q. By whom are you employed?

A. I am self-employed.

Q. What are your professional qualifications?

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford Law School. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983–1986.

Since 1983 I have been retained by governmental bodies, publicly owned utilities, and private organizations in 38 states to prepare expert testimony and analyses on engineering, economic, and financial issues related to electric utilities. My clients have included state utility commissions, attorneys general, consumer advocates, publicly owned utilities, and local, national and international environmental and consumer organizations. I have filed expert testimony before state regulatory commissions; before the U.S. Federal Energy Regulatory Commission and Atomic Energy Commission; and in state and federal court proceedings. A copy of my current resume is included as Attachment DS-1, and additional information about my work is available at www.schlissel-technical.com and www.ieefa.org.

Q. Have you previously testified before the Colorado Public Utilities Commission (the "PUC" or the "Commission")?

A. Yes, I filed expert testimony on behalf of Western Resource Advocates in the proceeding involving Public Service Company of Colorado's ("PSCo" or "the Company") compliance with the Clean Air Clean Jobs act.[1]

Q. What is the purpose of your Answer Testimony in this proceeding?

A. I have been asked by the Environmental Justice Coalition to address the following issues in my Answer Testimony in this proceeding:

1. PSCo's proposals to modify the ERP process.
2. PSCo's proposals to disallow new solar resources within 37 miles of Pueblo to seek a Just Transition Bid Credit and, in addition, to add a penalty to the bids from these new solar resources.

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[1] Proceeding No. 10M-245E, David Schlissel Cross-Answer Test. (Oct. 8, 2010); Proceeding No. 10M-245E, David Schlissel Answer Test. (Sept. 17, 2010).

3. The technical and financial risks and uncertainties associated with three key advanced technologies that have been discussed in the Pueblo Innovative Energy Solutions Advisory Committee (PIESAC) reports and whether these technologies would be effective tools for decarbonization. These three advanced technologies are small modular nuclear reactors (SMRs), new natural gas-burning turbines with carbon capture & sequestration (CCS), and hydrogen-burning turbines.
4. Whether a renewable energy park in Pueblo would provide benefits for Pueblo as an alternative to any of these three technologies.

This testimony contains my findings and recommendations on each of these issues.

Q. Please summarize your findings.

A. My main findings are as follows:

1. PSCo's proposal to spend any of the up to $100 million in funding through its proposed Carbon Free Future Development policy implementing costly and speculative technologies would impose pollution and public health and safety risks on nearby communities. And at the same time, it would pose very expensive burdens for the Company's ratepayers.
2. Encouraging the building of a gas plant in Pueblo to replace the retiring Comanche coal plant through the use of a just transition modeling credit is a bad idea for many reasons, including the climate crisis the world is now facing. It also sends the wrong message, particularly when there are better options for Pueblo, such as the development of a renewable energy park.
3. The Company's study in support of its proposal to reverse the Commission's support of additional solar capacity within a radius of 37-miles of Pueblo is inadequate.

4. The community and people of Pueblo deserve the support of PSCo's ratepayers and Colorado's taxpayers, as do those in other communities that have suffered when fossil-fired power plants are shut down due to their poor economics and/or demonstrated impact on the world's climate. But this does not mean that ratepayers and taxpayers should be financial guinea pigs to pay for expensive alternatives that include unproven technologies that will not be effective and reliable tools for decarbonization.

5. Contrary to the claims of supporters of SMRs and new large nuclear reactors:

    A. It is extremely likely that any future SMRs or large reactors will cost far more and take far longer to build than the nuclear industry and its supporters now claim. That has been the long history of nuclear power in the United States, and I see no evidence that leads me to believe it will change anytime in the foreseeable future.

    B. There is no credible evidence to support the claim that the costs of building multiple copies of the same SMRs will decline over time.

    C. There is no existing nuclear infrastructure, including factories, to support the construction of large numbers of new reactors.

    D. Neither new SMRs nor large reactors will be effective tools for decarbonization due to their high construction costs and the fact that they will likely not be online for at least a decade to 15 years. There are significantly less expensive alternatives for decarbonization that can be in operation much sooner. In fact, it is far more likely that new SMRs and large reactors will compete with, rather than complement, renewable solar and wind resources for space on the transmission grid.

6. None of the SMR designs currently being promoted in the United States have ever been operated, are currently under construction (beyond some preliminary site development work) or have even been licensed by the Nuclear Regulatory Commission (NRC)

7. SMRs built in China and Russia have experienced significant cost overruns and substantial schedule overruns.

8. The nuclear industry and its supporters have generally been successful in shielding the estimate costs and construction schedules for their proposed SMRs and large reactor projects from the public. Nevertheless, it is clear that the estimated costs of the leading SMR designs being marketed in this

country have increased dramatically and their schedules have been pushed back by years, even though none are already under construction or have been licensed by the NRC.

9. It is reasonable to expect that further significant cost increases and schedule delays will be experienced by these projects before they go into commercial service, if, indeed, they are ever built. In fact, the reality of reactor construction is that cost increases and schedule delays should be anticipated at all stages of project development.

10. Reactor vendors claim that using modular reactor designs and the installation of factory-built modules will reduce both the costs of new SMRs and large reactors and their schedules. However, these did prevent the cost of the two recently completed reactors in Georgia from growing from an initially estimated $14 billion to $36 billion. Nor did they prevent the more than six years of schedule overruns the two units experienced.

11. The new nuclear Investment Tax Credit (ITC) will not reduce the cost of building a new reactor, except for perhaps a reduction in some financing costs. However, the nuclear ITCs will transfer a significant portion of the cost of building new SMRs and large reactors from ratepayers to taxpayers—who are actually the same people.

12. Even with the maximum 50% nuclear ITC, the estimated cost of the power from SMRs is far higher than the cost of the power from renewable solar and wind resources and solar + battery storage projects.

13. Contrary to the claims of supporters of carbon capture & sequestration (CCS), there is no evidence that any existing CCS project has captured more than 80% of the carbon dioxide (CO_2) it processes, let alone the greater than 95% capture rates that are being claimed for proposed projects.

14. As even the Company has acknowledged, it is more difficult to capture the CO_2 from a gas-fired power plant than from other potential industrial facilities or a coal-fired generator.

15. The only actual experience capturing CO_2 at a commercially size gas-fired power plant was a small-scale project that captured the CO_2 from only 7% of the plant's flue gases. And that project was ended twenty years ago.

16. This limited experience of capturing CO_2 from a single gas-burning plant has not been accepted by many in the utility industry as proving or demonstrating that CCS will effectively and reliably capture CO_2 over the

long term. And this is what it must do if it will be an effective tool for decarbonization.

17. Although small-scale testing of new carbon capture technologies has shown promise for achieving higher capture rates, scaling up from the results of small-scale tests to commercial operations has been a challenge for some new technologies.

18. When CCS proponents talk about the high capture rates that future projects will achieve, they usually focus solely on the emissions from a power plant and not the plant's entire life cycle CO_2e (equivalent) that would include the upstream methane emitted between the well where it is produced and the plant or the CO_2 produced if they captured CO_2 is used for enhanced oil recovery (EOR). When these are included, a project's effective capture rate is far lower than that of the plant alone.

19. PSCo has not committed to not selling any of the CO_2 captured by a CCS project at any of its gas-fired plants for EOR.

20. Because the federal tax subsidies (called 45Q tax credits after the section of the tax law which provides for them) are based on how many tonnes of CO_2 a project captures, owners of gas-fired plants will have an incentive to run their plants as much as possible. This is because the higher the tonnes of CO_2 produced by the plant, the higher the number of 45Q tax credits it could potentially receive. This is called "farming for tax subsidies" by some.

21. The estimated costs of capturing CO_2 have gone up, as have the 45Q tax credit values, not down as supporters, including the U.S. Department of Energy (DOE) claimed as recently as a few years ago.

22. The prices of gas turbines have increase substantially in recent years and lead-times for new turbines have lengthened significantly due to increased competition and the decision by vendors not to expand their manufacturing facilities.

23. The PIESAC's estimated cost for a new gas turbine with CCS is far too low. Their $1.345 billion estimated cost figure might cover the cost of a 500 megawatt (MW) turbine, but I expect that the cost of the equipment and components for CCS would easily drive the total cost to more than $2 billion, and then doesn't account for inflation.

24. The burning of green hydrogen produced using the electricity from solar resources in a turbine to produce electricity is a very inefficient and wasteful process.

25. On average, producing enough green hydrogen to generate each MWh of electricity from burning it in a very efficient turbine would consume 3.86 MWh of electricity from renewable resources—for a round trip efficiency of just 26%. Producing enough green hydrogen to generate electricity in a very efficient combined cycle unit would be a bit more efficient, but would still require 2.68 MWh of electricity from renewable resources for each MWh of electricity generated by the power plant—a round trip efficiency of 37%. This assumes that the turbine would be located right next to the renewable resources—so there are no losses assumed in these calculations from transporting or storing the green hydrogen. The same inefficiency should be present even if the electricity came from an SMR.

26. Bottom line, producing green hydrogen (or whatever color the hydrogen from an SMR is) and then burning it as a fuel in power plant is a waste. Green hydrogen should be used only where absolutely essential and where there is no feasible alternative.

27. Blue hydrogen produced from methane is not clean or low carbon. Depending on the assumptions made, blue hydrogen made at a facility without the capability to capture any CCS, has a very high carbon intensity of between 10 and 20 kilograms of CO_2e emissions into the atmosphere for each kilogram of blue hydrogen produced. 99% of the blue hydrogen produced in the world is made without carbon capture.

28. Even with carbon capture, blue hydrogen is still not clean or low carbon, despite what the DOE may claim. Depending on the assumptions, blue hydrogen with more than 94% of the CO_2 being captured still has a carbon intensity significantly higher than the 4.0 kilograms of CO_2e per kilogram of hydrogen federal U.S. clean hydrogen standard.

29. Only three hydrogen production facilities in the world currently capture any of the CO_2 created during the conversion of the methane in natural gas to hydrogen. Only one of these has a CO_2 capture rate higher than 60%, and that facility's capture rate is just 68% if you include the CO_2 emissions from the carbon capture process itself.

30. Although it is not impossible, it would remain a big gamble how high a CO_2 capture rate actually will be achieved in new hydrogen production facilities.

31. Hydrogen is an indirect greenhouse gas. Changes in its abundance in the atmosphere will change the lifetime and concentration of methane, a very potent greenhouse gas.

32. Hydrogen is the smallest and the lightest molecule. Due to its small size, hydrogen is a "slippery" molecule that can be expected to leak into the atmosphere at every stage of the hydrogen value chain, from production to compression to pipeline transport through final use.

33. Hydrogen also has an energy density, on a volume basis, less than one-third that of methane. This means that approximately three times as much hydrogen as methane is needed to provide the same amount of energy to generate an equal amount of electricity in a turbine.

34. The significance of this is that if you want to achieve significant reductions in CO_2 by burning a blend of hydrogen and natural gas, you either have to burn a gas that is 100% hydrogen or a blended gas with as high a percentage of hydrogen as you can get.

35. For example, burning a blend of 20% hydrogen and 80% methane produces only a 7% reduction in CO_2 emissions. Burning a 50% hydrogen blend reduces CO_2 emissions by only 24%.

36. Due to its physical and chemical properties, transporting hydrogen in the existing natural gas pipeline network could lead to pipe cracks, failures, or other problems as a result of the materials used in the construction of the pipelines.

37. Only a small portion of the natural gas pipeline network in the United States is made from materials that are compatible with hydrogen or a hydrogen-natural gas blend.

38. Potential remedial measures could either be the construction of new pipelines or sections of pipelines, with materials compatible with hydrogen, but this would be very time-consuming and very expensive, if it is possible. Or the hydrogen could be blended with natural gas below certain levels. But this would mean lower reductions in CO_2 emissions when the blended gas is burned.

39. Vendors claim there are currently turbine models made from materials and with design features compatible with hydrogen. But this may be the easiest step if the existing natural gas pipeline is not compatible with transporting a blended gas with a high concentration, by volume, of hydrogen and if the production of hydrogen continues to be a dirty process in terms of the carbon intensity of the hydrogen produced.

40. It is impossible to say how long it would be possible for PSCo to add a turbine that can burn a blend gas with a high percentage of hydrogen.

41. More difficult questions are when if ever, will there be a supply of truly clean, low carbon hydrogen available to PSCo to purchase? And when will there be a hydrogen-compliant pipeline infrastructure available to transport that clean hydrogen from where it is produced to Pueblo? There are currently no answers for either of these questions.

42. I conclude that it will be a very long time before there will be truly clean blue hydrogen available at a site in Pueblo to be burned in a turbine, if, indeed, it is ever possible. And until that happens, burning hydrogen will not be an efficient and reliable tool for decarbonization.

43. A renewable energy park in Pueblo would provide significant benefits to PSCo, its ratepayers, the state of Colorado, and the local economy and taxpayers in and around Pueblo. A renewable energy park could:

A. Provide energy to the grid 99% time matched with a corrected version of the Comanche Unit 3 dispatch schedule.

B. Create over 350 jobs and up to $40 million in annual tax revenue to replace that lost with the retirement of Comanche Unit 3.

C. Diversify Pueblo's economy and tax base because the energy park would be made up of multiple different resources.

D. Flexible loads included in the energy park are central to jobs, tax revenue, and reliability because they help keep energy in Pueblo, help balance additional renewable energy capacity, and provide energy back to the grid from thermal batteries.

E. The cost of a renewable energy park to Colorado's electricity ratepayers could less than half that of an SMR ($3 billion vs. $5 to $10 billion or more)

F. Because a renewable energy park could start being built in the next few years, the just replacement tax revenues would be reduced and jobs and energy from Comanche could be replaced sooner.

44. A renewable energy park also would give PSCo valuable flexibility in energy planning and would enable it to avoid being trapped in expensive nuclear and gas investments should the dramatic increases in future demands that the Company currently forecasts not materialize or materialize differently than expected. At the same time, new resources could be added in a relatively shorter period if demand grows at a higher rate than now expected. This flexibility is vital in today's dynamic energy transition.

45. An energy park with an SMR, a gas turbine with CCS, or a hydrogen-burning turbine would not provide the same benefits as a renewable energy park as envisioned in the April 2025 Energy Innovation report.

Q. Please summarize your recommendations.

A. I recommend that the Commission take the following actions:

1. Reject PSCo's proposal to encourage the development of gas plants in just transition communities through the just transition modeling credit.

2. Reject PSCo's proposal to disallow the just transition credit and to impose an $8.00/kW-year bid penalty for solar projects located within a 37-mile radius of Pueblo.

3. Prohibit PSCo from funding any steps to develop any SMR or large-scale nuclear reactor or gas + CCS project through the Carbon Free Future Development policy.

4. Direct the Company to model a wide range of potential SMR capital costs and construction times given the significant potential for cost and schedule overruns on SMR or large reactor projects.

5. Direct the Company to make public to its ratepayers any information it obtains about the estimated construction costs (both overnight and all-in), power costs and construction schedules of the SMR and large-reactor designs and the CCS projects designs it is modeling or otherwise evaluating.

6. Direct the Company to model wide ranges of carbon capture rates, CCS construction costs, and gas turbine prices and to model the full life cycle CO_2e emissions of each turbine with CCS scenario that it models or otherwise evaluates.

7. Find that burning green hydrogen made from renewables or the hydrogen produced using the electricity from an SMR or a large reactor in a turbine to produce electricity will be a wasteful process and not an effective tool for decarbonization.

8. Given the technical uncertainties and risks I have outlined in this testimony, find that burning blue hydrogen made from the methane in

natural gas to produce electricity will not at any time in the foreseeable future be an effective and reliable tool for decarbonization.

9. Direct PSCo to study the development of a renewable energy park and to fund this study and a related stakeholder process with the funds it is seeking for its proposed Carbon Free Future Development policy.

10. Direct the Company to file a report in this proceeding no later than one year after the Commission's final Phase I decision that discusses and recommends the next steps for establishing a renewable energy park in Pueblo. This report should discuss and recommend the next steps for establishing that energy park and summarize the feedback and proposals the Company received from participants in the stakeholder process. Parties should have thirty days to submit comments responding to PSCo's Pueblo renewable energy park report.

11. Direct the Company to investigate geothermal and long-term battery and thermal storage alternatives with funds from its proposed Carbon Free Future Development policy.

12. Require the Company to ensure that the Advisory Committee it is proposing to establish as part of its Carbon Free Future Development mechanism include a diverse range of Pueblo community members, not only those who support SMRs and gas + CCS options. The Advisory Committee should also include non-government representatives who are PSCo ratepayers.

Q. What materials have you reviewed and what analyses did you review as part of the preparation of your Answer Testimony?

A. I have reviewed the Company's Direct and Supplemental Direct Testimony in this proceeding and its responses to data requests submitted by parties active in this proceeding that were related to the issues I discuss in this testimony. I also have read the December 2023 and January 2024 PIESAC reports on alternatives to the retiring Comanche coal plant. In addition, I have reviewed articles, reports, studies, and papers on issues related to nuclear power plant technologies, costs, and schedules, the feasibility and costs of carbon capture and sequestration, and the feasibility, costs and efficiency of the production, transportation, and use of hydrogen, including the burning of it in turbines to generate electricity. Finally, I have reviewed studies published by Energy Innovation on energy parks as well as research published by Energy Innovation and others on long-term storage technologies such as thermal storage.

II. PSCo's Proposals to Modify and Evolve the ERP Process

Q. What types of resources has PSCo typically built and acquired in its recent electric resource plans (ERPs)?

A. It is my understanding that in its most recent ERPs, PSCo has largely built and acquired new wind, solar, battery storage, and gas resources through a competitive bidding process.

Q. Does PSCo expect to build and acquire similar resources in Phase II of this ERP?

A. Yes. Similar to the results of its recent ERPs, PSCo expects that it will build and acquire significant amounts of wind, solar, battery storage, and gas resources in Phase II of this proceeding.[2]

Q. Does PSCo propose to modify and evolve the ERP process in this case?

A. Yes. PSCo claims that the most recent 2021 ERP proceeding "stressed [the ERP] process on several fronts," and thus the Company proposes to evolve the ERP process in this case.[3] Specifically, PSCo proposes the following three components

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[2] *See, e.g.*, Hr'g Ex. 101, Jack Ihle Direct Test. Rev. 1 at 61:3 (Oct. 15, 2024).
[3] *Id.* at 22:32–23:1; *see also id.* at 42:12–44:4.

for evolving the ERP process: (1) streamlining the bid evaluation process, (2) looking "beyond the traditional [resource acquisition period] to find ways to encourage evaluation and evolution" of new and longer lead-time carbon free technologies, and (3) driving project development into areas with locational needs.[4]

Q. Do you have concerns with PSCo's proposals to evolve the ERP process in this manner?

A. Yes. As I discuss in detail below, I oppose PSCo's proposal to encourage the development of gas plants in just transition communities through the just transition modeling credit. I also oppose PSCo's proposal to disallow the just transition modeling credit and to impose an $8.00/kW-year bid penalty for solar projects located within a 37-mile radius of Pueblo.

In addition, I oppose PSCo's proposal to spend any of the up to $100 million in funding through the Carbon Free Future Development policy for implementing what I believe would be costly and speculative technologies that would impose pollution and public health and safety risks on nearby communities, and, at the same time, pose very expensive burdens for the company's ratepayers. These include SMRs, gas plants with carbon capture, and gas plants (turbines) that burn hydrogen. Although I agree with the general principle that utilities should study and encourage the development of advanced clean energy technologies, PSCo's proposal to spend up to $100 million in ways that could bias

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[4] *Id.* at 43:5–11.

future analyses in favor of costly and speculative technologies would be a significant step in the wrong direction.

III. <u>Just Transition Bid Credits and the Pueblo Solar Penalty</u>

Q. How does PSCo propose to encourage the development of new generation and storage resources in Pueblo and other just transition communities?

A. The Company proposes to encourage the development of new resources in just transition communities by providing a modeled benefit to projects located in a just transition community.[5] The bids for projects located in a just transition community would receive a $/kW-month or $/MWh modeling credit that "would scale based on property tax contribution and projected long-term jobs created, emphasizing the importance of both property tax contributions and workforce opportunities in just transition communities."[6]

Q. Do you support these just transition modeling credits?

A. In part. I agree with EJC witness Jamison Valdez and support the concept of encouraging the approval of bids in just transition communities for clean energy resources such as solar, storage, and wind. However, I also support the EJC's opposition to the construction of any new gas-fired power plants in Pueblo, and its recommendation that the Commission order PSCo to not accept any bids in Phase II for gas plants in Pueblo. Alternatively, if the Commission allows bids for gas plants in Pueblo, I agree with the EJC's opposition to PSCo's proposal to

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[5] *Id.* at 47:3–49:19.
[6] *Id.* at 48:6–8.

encourage the development of a polluting gas plant in Pueblo through the use of the just transition modeling credit.

Q. What are your views on building a gas plant in Pueblo and encouraging that result through the use of a just transition modeling credit?

A. I understand and support the EJC organizations' desire to not replace the coal plant in Pueblo with another polluting fossil fuel resource. That's a bad idea for many reasons, including the climate crisis the world is facing right now. And it would definitely send the wrong message, particularly when there are much better options for providing a just transition in Pueblo, such as the renewable energy park I discuss below. The Commission should prevent this unjust result by disallowing bids in Phase II for any gas plants located in Pueblo. And if it doesn't do that, it certainly should not put a thumb on the scale in favor of building a gas plant in Pueblo though giving them a just transition modeling credit.

Q. Does PSCo propose to discourage the development of any resources in Pueblo?

A. Yes, the Company proposes to penalize solar bids in Pueblo. Specifically, under PSCo's proposal, any solar bids within a 37-mile radius of Pueblo would not receive a just transition modeling credit and would instead be assessed an $8.00/kW-year penalty.[7]

[7] Hr'g Ex. 102, Jon Landrum Direct Test. 45:11–46:17 (Oct. 15, 2024).

Q. Should the Commission adopt the Company's proposal to withdraw the just transition credit and to impose a penalty on renewable resources within 37 miles of Pueblo?

A. No.

Q. What are your reasons for this conclusion?

A. The Company's "study" in support of its proposal to reverse the Commission's previous support of additional solar capacity is inadequate.[8] The study is extremely brief, it fails to include the experience in ERCOT, and it ignores what the impact would be if it were assumed that additional storage capacity would be added in the Pueblo area at the same time as additional solar capacity. As a result, the study posits a scenario that I don't believe is realistic—that is, that at this time or in the future, the Company would choose, or the Commission would permit anyone, to add or to select a bid to add an additional gigawatt of solar capacity in the Pueblo area, or anywhere else, without including significant battery storage capacity. Given the demonstrated reliability benefits that adding storage capacity has shown in CAISO and ERCOT, I think that the company's study is unrealistic and biased.

It also is interesting that of the three ISO's included in Table 3 of the Company's study, the one with the most solar and battery storage, CAISO, has by far the lowest listed Regulation Up cost.[9] And the other two ISOs that have far,

[8] Hr'g Ex. 102, Attach. JTL-2.
[9] *Id.* at 5.

far less solar and battery storage capacity than CAISO, have Regulation Up costs in this same table that are more than double that of CAISO.

When asked in discovery to explain why Table 3 did not include any Regulation Up cost for ERCOT, PSCo's response was simply: "The Company researched Regulation Up costs for CAISO, SPP, and MISO. The Company did not research Regulation Up costs for ERCOT."[10] But no explanation was provided as to why the costs for ERCOT were not researched.

Q. Do you believe that geographical diversity is an important consideration when siting resources?

A. Absolutely. That's why I support developing renewable energy parks in Pueblo (and other just transition communities). It may also make sense to site renewable energy parks in or near the Company's main load center(s). However, PSCo should not encourage bids for a gas plant in Pueblo, while also penalizing bids for solar facilities in Pueblo.

[10] PSCo Resp. to EJC 4-1(e) (Attach. DS-2 at 1).

IV. The Carbon Free Future Development Proposal and the PIESAC Reports

Q. What is the Carbon Free Future Development policy?

A. In addition to the typical ERP process that features an all-source solicitation, PSCo has proposed a new ERP process that would provide preliminary funding for "the next generation of clean technology, with a focus on dispatchability and technological advancement."[11] PSCo refers to this as its Carbon Free Future Development policy, and it proposes a $100 million budget to fund these resources.[12]

Q. What types of resources would PSCo fund through the $100 million Carbon Free Future Development proposal?

A. Under the Company's proposal, the Commission would determine which specific projects would receive funding through the Carbon Free Future Development mechanism in Phase II of this proceeding.[13] However, PSCo states that nuclear, geologic carbon capture, hydrogen, geothermal, and pumped hydro are the types of resources that require a longer timeframe to develop and that could receive funding and benefit from the Carbon Free Future Development proposal.[14]

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[11] Hr'g Ex. 101, Ihle Direct 81:11–13.
[12] Hr'g Ex. 103, Justin Tomljanovic Direct Test. 52:1–61:11 (Oct. 15, 2024).
[13] *Id.* at 56:7–17.
[14] *See* Hr'g Ex. 101, Ihle Direct 50:19–51:11.

Q. Does the EJC have an interest in which types of resources PSCo may fund in Pueblo through the Carbon Free Future Development policy?

A. Yes. As Mr. Valdez explains in his Answer Testimony, the organizations in the Environmental Justice Coalition represent community members in Pueblo and the EJC is uniquely focused in this case on ensuring a just transition for Pueblo as the Comanche coal plant retires. Mr. Valdez explains that the EJC supports building truly clean, renewable energy resources in Pueblo and it opposes replacing the heavily polluting coal plant with new resources that would continue to pose disparate health and safety burdens on the Pueblo community.

Q. Are there other proposals relevant to this case to build a nuclear facility, a gas plant with carbon capture, or a gas plant that burns hydrogen in Pueblo?

A. As part of its attempt to advance a just transition in Pueblo, PSCo relies heavily on a December 2023 report issued by the PIESAC.[15] The PIESAC issued an additional report one month later, in January 2024, which strongly endorsed building SMRs or a new combined cycle gas plant with carbon capture in Pueblo.[16] To accommodate the PIESAC's recommendations, PSCo changed its long-term ERP modeling approach to include "an expanded set of generic resources to bring more advanced technology options . . . into the long-term modeling."[17]

[15] *See, e.g.*, *id.* at 45:13–46:7.
[16] PIESAC, *Pueblo Innovative Energy Solutions Advisory Committee Report* 3–4 (2024), https://www.xcelenergy.com/staticfiles/xe-responsive/Archive/PIESAC%20Written%20Report.pdf.
[17] Hr'g Ex. 101, Ihle Direct 57:18–20.

Q. Do you have any initial comments regarding the PIESAC and its reports?

A. Yes. Mr. Valdez's Answer Testimony explains the flaws in the PIESAC process and why the PIESAC reports do not represent the views of many Pueblo community members.

From my perspective, I believe that the community and people of Pueblo deserve the support of PSCo's ratepayers and Colorado's taxpayers, as do those in other communities that have suffered when fossil-fired power plants are shut down due to their poor economics and/or demonstrated impact on the world's climate. But this does not mean that ratepayers and taxpayers should be financial guinea pigs to pay for expensive and unproven and unreliable technologies such as (1) building an SMR reactor in Pueblo, (2) burning natural gas and capturing the CO_2 produced when the gas is combusted, and (3) burning hydrogen in gas turbines that will not be effective tools for decarbonization. I will discuss the uncertainties and risks associated with each of these technologies in the next sections of this testimony.

V. SMRs

Q. How are SMRs and other nuclear technologies at issue in Phase I of this proceeding?

A. Nuclear technologies are at issue in Phase I of this case in several ways. First, as I discussed above, PSCo anticipates that nuclear resources would be eligible for the $100 million Carbon Free Future Development funding. Second, the company may propose funding for specific nuclear facilities in Phase II. Third, in response to the PIESAC's recommendations, PSCo included AP1000 nuclear power plants and SMR plants in its long-term generic modeling.[18]

Q. Before you discuss SMRs. What definitions do you use when you discuss reactor (SMR or large) construction costs?

A. Consistent with other analyses, I use two definitions of costs when analyzing reactor construction costs. The term "overnight costs" is the hypothetical cost 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. Some analyses have used variations on these two definitions, but I regularly use these two definitions.

Q. What project milestones do you use when you calculate reactor construction schedules?

A. Consistent with the International Atomic Energy Agency's (IAEA) Power Reactor System (PRIS), I define the start of a reactor's construction as the beginning of the pouring of the reactor building's foundation. The DOE commonly calls this a project's "first nuclear concrete" date. The end of construction is the date when the reactor is declared to be in commercial operation, or in rarer cases, the date when it is cancelled.

[18] *Id.* at 57:18–58:7; Hr'g Ex. 102, Landrum Direct 83:7–10.

Q. What claims do nuclear supporters make about the benefits of building SMRs?

A. Nuclear supporters generally make a number of unproven claims, such as the following:

1. 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.
2. Building multiple copies of the same SMR design will lead to cost declines over time—that is, what is generally called a "positive learning curve."
3. New SMRs will be in service by the late 2020s or the early 2030s, including those with technologies that have never been built or that have failed in the past.
4. SMRs will be effective tools for addressing climate change and will be able to complement variable renewable resources on the grid.

Q. Do you agree with these claims?

A. No. As this testimony will show:

1. It is extremely likely that any future SMRs or large reactors will cost far more and take far longer to build than the nuclear industry and its supporters now claim. That has been the long history of nuclear power in the United States, and I see no evidence that leads me to believe it will change anytime in the foreseeable future.

2. There is no credible evidence to support the claim that the costs of building multiple copies of the same SMRs will decline over time.

3. There is no existing nuclear infrastructure, including factories, to support the construction of large numbers of new reactors.

4. Neither new SMRs nor large reactors will be effective tools for decarbonization due to their high construction costs and the fact that they will likely not be online for at least a decade to 15 years. There are significantly less expensive alternatives for decarbonization that can be in operation much sooner.

Q. Are SMRs really small?

A. No. Although SMRs are generally considered as under ~350 MW in capacity, that's not really that small. This is especially true because a number of the reactor designs assume that multiple SMR modules will be installed as part of the same project. For example, NuScale is one of the leading SMR developers and it is currently marketing a 77MW reactor module. If six of these modules were built on the same site, the total project would be 462 MW. If twelve modules were built at the same site, the total project would be 924 MW, which would be nearly as large as the reactors that have been built in the United States.

Q. What does the term "modular" in the name refer to?

A. The term "modular means that the SMRs would be built in factories and then assembled on site. As the DOE has explained:

> Because civil works construction drives nuclear capital cost, the value proposition for SMRs centers around maximizing design

> standardization and factory production. To realize this potential, SMRs must move a substantial portion, e.g., more than ~50% of overall spend into the factory setting; without this, an SMR risks being a civil works construction project without the benefit of economies of scale. SMR construction will require dedicated modular assembly capabilities and the requirements will differ by design. Unique capacity will be required for each design; design down-selection will be critical for standardization and reducing total industry costs.[19]

Q. Do any of the companies currently marketing SMRs in the United States actually have factories in which modules of their reactors are being built?

A. No.

Q. Have any of the SMR vendors indicated when their SMR factories will be built and whether they will be built in the United States?

A. They may have, but I've not seen any.

Q. Is this a risk for parties that are proposing to own or buy power from SMRs?

A. Yes. After all, one of the key claims by supporters of SMRs is that the reactors will be less expensive to build because key reactor modules will be manufactured in factories and assembled on site. Yet, to my knowledge, no SMR vendor has yet opened a single factory.

Q. What are the other significant risks associated with SMRs?

A. The other significant risks for any party seeking to own or buy power from an SMR include:

1. Uncertainty about the SMR's construction cost and cost of power.

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[19] DOE, *Pathways to Commercial Liftoff: Advanced Nuclear* 27 (2024), https://liftoff.energy.gov/wp-content/uploads/2024/10/LIFTOFF_DOE_Advanced-Nuclear_Updated-2.5.25.pdf.

2. Uncertainty about who will bear the risk of construction cost overruns—the SMR vendor, the party owning or buying power from the SMR and its customers or ratepayers, or federal or state taxpayers.
3. Uncertainty about when the SMR will be in service, if, indeed, it is completed at all.
4. Uncertainty about using new technology that has not been proven to be reliable and safe at commercial scale and/or that has failed in the past.
5. Uncertainty due to the track records, or the lack of any track record, of the numerous companies, including many recent startups, marketing SMRs.
6. Whether the currently projected demand for the power and electricity from proposed SMRs will actually materialize by the time they will be completed.

Q. Will you be addressing these risks in this testimony?

A. Yes. Although I will mainly be focusing on the first of these risks—cost and schedule.

Q. Is the interest in SMRs a recent development?

A. Initially, the reactors built in the U.S. was fairly small. Then, in the mid-to-late 1960s, companies transitioned to building larger reactors in order to take advantage of economies of scale that made them less expensive than smaller reactors on a dollar-per-kilowatt basis. However, despite these economies of scale, the costs of larger reactors skyrocketed starting in the 1970s, leading to what was called "rate shock" when their costs were added to utility rate bases.

Although there was lots of hype about nuclear renaissances in the 1990s and the first decade of this century, eventually only four new reactors have started construction in the United States since 2000.

Starting in about 2010, the nuclear industry and its supporters began to push to go back to smaller modular reactors that they claim will cost less, be faster to build than the previous larger reactors, and would be flexible enough that they can complement renewable resources on the grid. Thus, the industry had gone from small reactors to larger reactors, and now back to smaller reactors.

Q. Is there still interest in building larger reactors?

Yes. The DOE's September 2024 report appears to be re-embracing building larger reactors again. The report notes that "[l]arge reactors provide powerful economies of scale," and that "[d]esigners and operators chose to make nuclear reactors bigger over time to take advantage of scale in operations."[20]

Q. Will SMRs have the same economies of scale as large reactors have had?

A. No. As a result, according to the DOE, SMRs will be more expensive than large reactors as measured by dollars per megawatt ($/MW) of capacity and dollars for megawatt hour of electricity produced ($/MWh).[21]

[20] *Id.* at 26.
[21] *Id.* at 27.

Q. Are any of the new SMR designs being marketed in the United States currently operating or under construction?

A. No. None of the SMR designs being promoted in the United States have ever been operating, are currently under construction (beyond some preliminary site development work), or have yet been licensed by the NRC.

Q. Have any of the companies now competing to sell their SMR designs in the United States had any actual experience designing and building reactors?

A. A few have experience, but many appear to be startups with little to no corporate experience in designing, building or operating reactors.

Q. Have any SMRs been built in other countries in recent years?

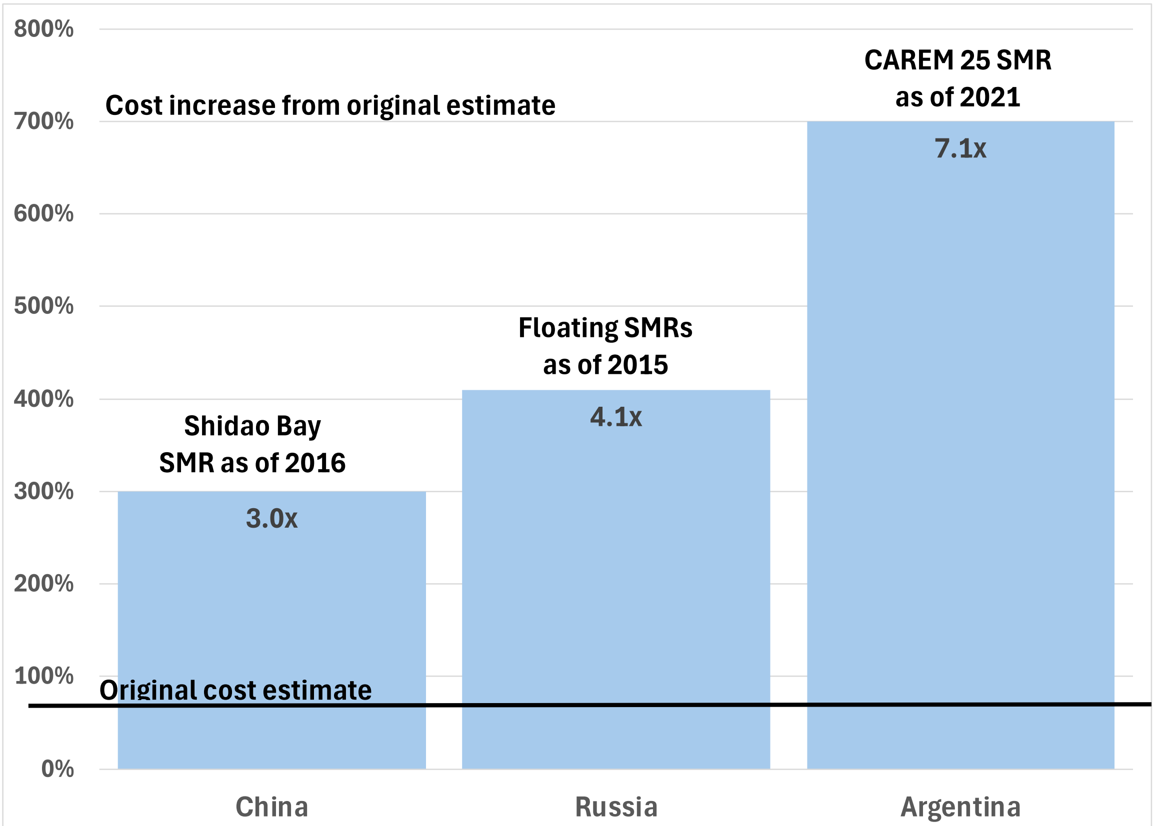
A. Yes. There is one SMR in China and two floating SMRs operating in Russia. Another SMR is currently under construction in Argentina.

Q. Have these SMRs experienced any cost overruns?

A. Yes. The construction of these SMRs have experienced major cost overruns. Construction of the two floating SMRs in Russia began in 2007, followed by the start of construction of the Shidao Bay SMR in 2012. Although the Russia SMRs did not enter service until 2020, and Shidao Bay in China did not begin commercial operation until December 2023, the most recent cost data I could find was 2015 for Russia and 2016 for China.

As shown in Figure DS-1, even at these relatively early dates, with years of construction remaining, the estimated cost of the Chinese SMR had already tripled and the estimated cost of the Russian SMRs had quadrupled.

Figure DS-1: SMRs Built in Other Countries Have Experienced Significant Cost Overruns[22]



Given that each of these projects have had years of construction after each of the listed dates, it is reasonable to expect that the final cost of both of the Russian and Chinese projects were significantly higher than suggested in Figure DS-1 and that the ultimate cost of the SMR in Argentina, if it is completed, will be significantly higher, as well.

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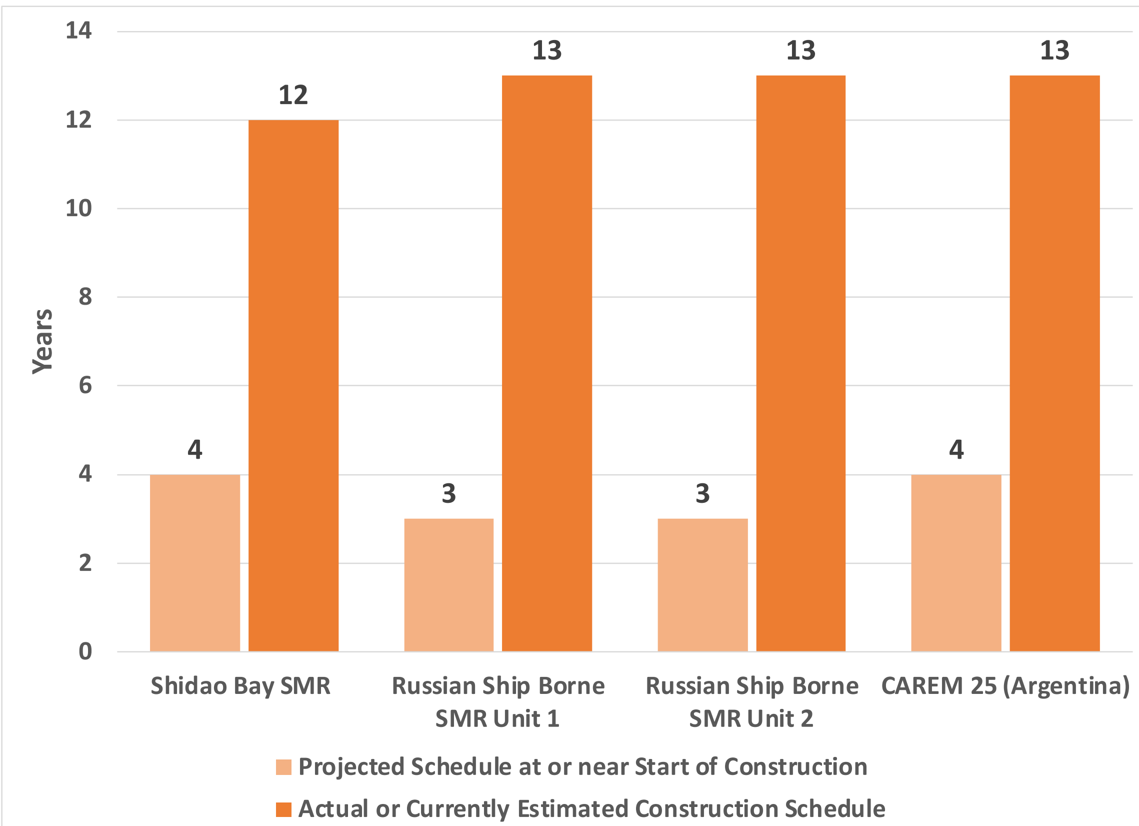
[22] *See, e.g.*, Mycle Schneider et al., *The World Nuclear Industry: Status Report 2024* (2024), https://www.worldnuclearreport.org/World-Nuclear-Industry-Status-Report-2024; Mycle Schneider et al., *The World Nuclear Industry: Status Report 2023* (2023), https://www.worldnuclearreport.org/World-Nuclear-Industry-Status-Report-2023.

Q. Did these SMRs also experience significant schedule overruns?

A. Yes. The initial construction schedule for the Shidao Bay SMR was four years. However, it did not achieve commercial operation until December 2023, or eleven years after construction began. The original construction schedule for the Russian SMRs was three years. It actually took thirteen years to complete construction.

Figure DS-2. SMRs Built in Other Countries Also Have Experienced Substantial Schedule Overruns



Q. What is the status of the SMR under construction in Argentina that is shown in Figure DS-1?

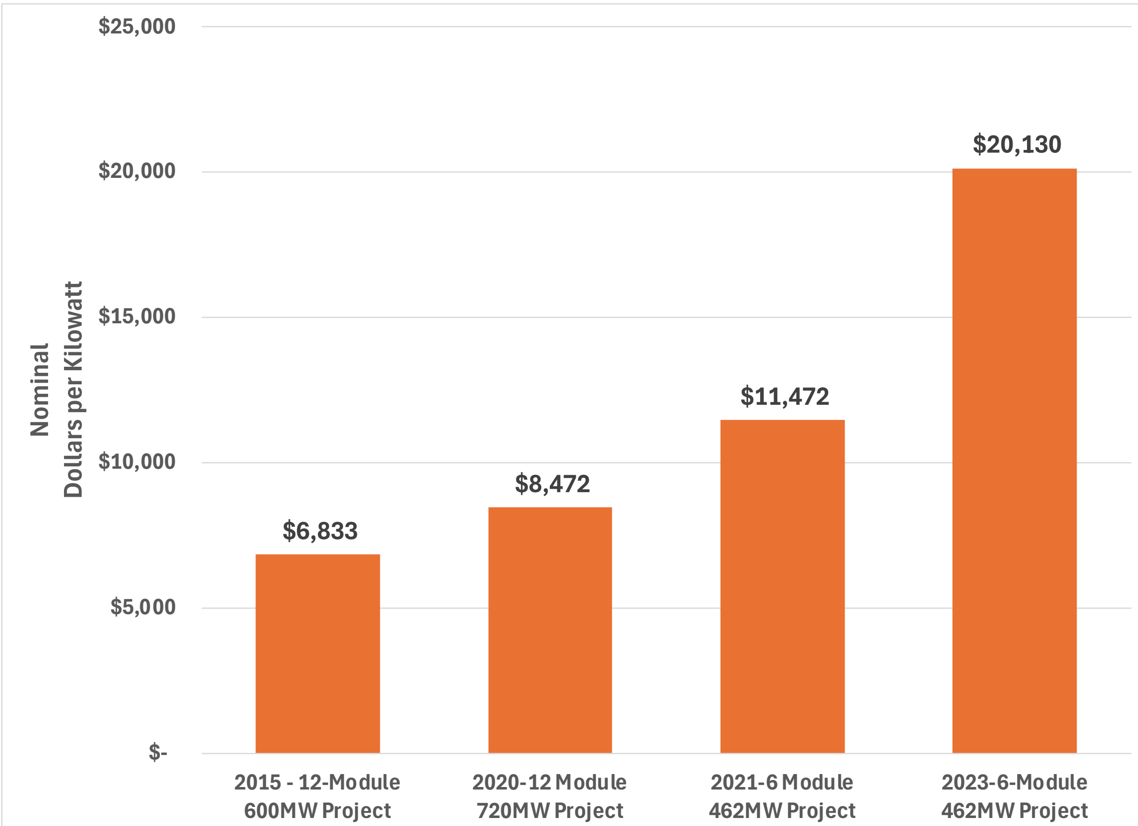
A. The construction of the CAREM 25 SMR in Argentina seems to have been a disaster. As shown in Figure DS-1, as of 2021, the SMR's estimated cost had gone up by a factor 600%. Its construction schedule had slipped from an estimated four years when it was started in 2014. The most recent information I have seen suggests it will take longer, on the order of thirteen years, to build the SMR.[23] This would mean that it wouldn't be completed until 2027 or 2028, and that's only if it stays on its most recent schedule.

Q. Have you seen any detailed information on the current estimated costs of any of the new SMR designs being marketed in the United States?

A. Unfortunately, almost all of the U.S. SMR developers have been able to shield their construction cost estimates from the public. However, the detailed cost data for the SMR that NuScale was proposing to build for the Utah Associated Municipal Power Systems (UAMPS) and its members has been somewhat more transparent. Being public municipal utilities, the UAMPS members who either had already signed contracts to buy the power from the proposed SMR or who were considering whether to do so had to release the revised project cost estimates to their customers. As Figure DS-3 shows, the estimated all-in construction cost of the proposed NuScale SMR almost tripled between 2015 and 2023.

[23] Schneider et al., *The World Nuclear Industry: Status Report 2023*, at 438–39.

Figure DS-3. The Estimated Cost of the Proposed First NuScale SMR Project Increased Dramatically Before It Was Cancelled[24]



Q. Have you seen any construction cost estimates for the NuScale project since 2023?

A. No. The project was scheduled to release a new cost estimate in late 2023 or early 2024, but the project was cancelled before that new estimate was released.

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[24] *See, e.g.*, David Schlissel & Dennis Wamsted, Inst. for Energy Econs. & Fin. Analysis, *Small Modular Reactors: Still Too Expensive, Too Slow and Too Risky* (2024), https://ieefa.org/resources/small-modular-reactors-still-too-expensive-too-slow-and-too-risky; David Schlissel, *NuScale Power, the canary in the small modular reactor market*, UtilityDive, Mar. 21, 2023, https://www.utilitydive.com/news/nuscale-power-small-modular-reactor-smr-ieefa-uamps/645554/; David Schlissel, Inst. for Energy Econs. & Fin. Analysis, *Small Modular Reactor Update: The Fading Promise of Low-Cost Power*

Q. Were the concerns about the SMR's rising construction costs and power prices a reason why the NuScale UAMPS project was cancelled?

A. Yes. The power contract for the proposed UAMPS SMR required parties who remained in the project after a license was granted by the NRC to pay all of the actual costs of the SMR, even if it was not finished, never provided any power, or was damaged or destroyed.[25]

In early 2023, UAMPS had said it would cancel the project if it could not get enough customers to sign agreements for 80% of the power from the 462 MW SMR. Obviously, it couldn't, and the project was cancelled. Increasing concern over the project's dramatically rising cost of power and the risk of writing blank checks for a project for which there was no definite cost were factors in UAMPS' failure to find enough parties to sign contracts for the SMR.

Q. What reasons did UAMPS provide for the increasing costs of its proposed SMR?

A. On January 2, 2023, UAMPS explained that the following factors were, in its view, responsible for the major increase in the cost of the proposed SMR:

- The interest rate used for the project's cost modeling had increased by approximately 200 basis points since July 2020.

from UAMPS' SMR (2022), https://ieefa.org/resources/small-modular-reactor-update-fading-promise-low-cost-power-uamps-smr.

[25] Carbon Free Power Project Power Sales Contract (Apr. 1, 2018), https://ieefa.org/wp-content/uploads/2022/02/Logan-CFPP-Power-Sales-Contract.pdf.

- Price increases had occurred in the previous two years due to inflationary pressures on the energy supply chain that, according to UAMPS, had not been seen for more than 40 years:
  - the Producer Price Index for Fabricated Steel Pipe had increased by 54%.
  - the Producer Price Index for carbon steel piping had increased by 106%.
  - the Producer Price Index for Electrical Equipment had increased by 25%.
  - the Producer Price Index for Fabricated Structural Steel had increased 70%.
  - the Producer Price Index for Copper Wire and Cable had increased 32%
  - the Producer Price Index for all construction commodities had increased by 45%.[26]

Q. Is it possible that other factors, such as design changes and potential problems with NuScale's SMR design, contributed to the project's rising costs?

A. Yes. For example, NuScale had originally marketed its SMR as being composed of modules of 50 MW each. However, by 2023, the designed power of each reactor modular had been increased to77 MW. Therefore, the UAMPS SMR had grown from a 12-module, 600 MW, project to one of 924 MW.

Q. Would the increasing interest rates and higher commodity prices also have impacted the estimated costs of SMRs with designs other than NuScale's?

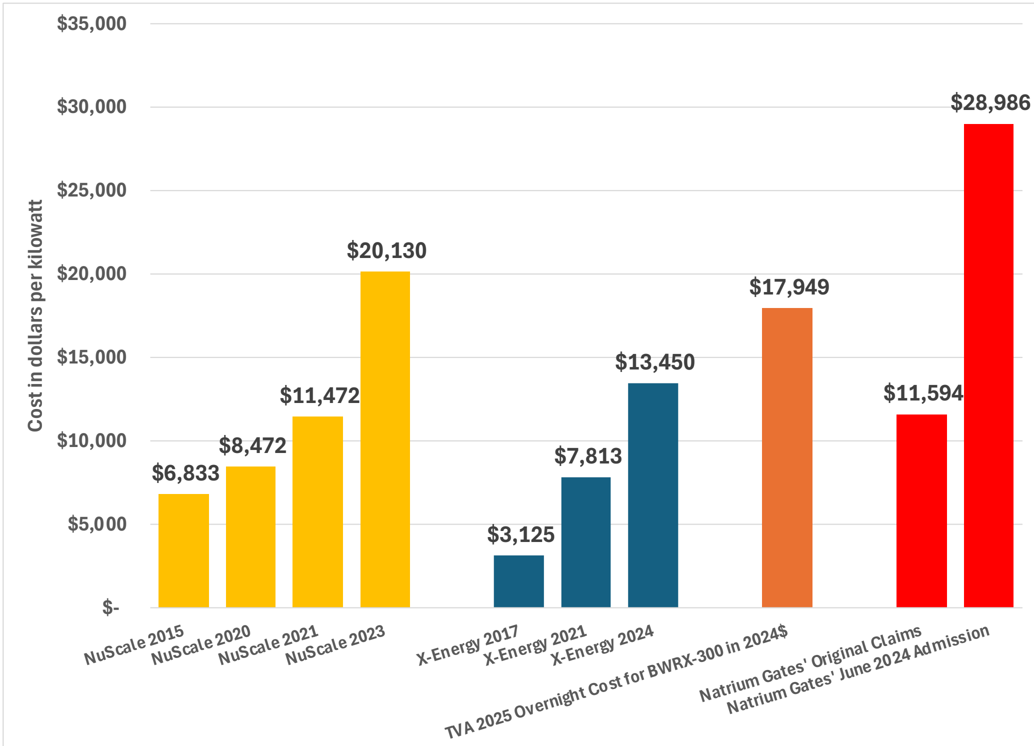
A. Yes.

[26] UAMPS Talking Points (Jan. 2, 2023), https://ieefa.org/sites/default/files/2023-01/UAMPS%20Talking%20Points%20_%20Class%203%20_%2020230102%20_%20Final.pdf.

Q. Have the estimated costs for any of the other SMRs currently being marketed in the United States indeed gone up in recent years?

A. Yes. As I noted above, the estimated costs of most proposed SMR designs have not been made public. However, some information on the estimated costs of three other SMR designs costs, in addition to NuScale's, can be found in media reports and statements to Congressional committees. Unfortunately, some of the SMR cost estimates available from these sources are unclear as to whether they refer to all-in costs or just overnight cost estimates. Nevertheless, they do give a clear picture that the costs of at least three other leading SMR vendors have increased significantly. This data is shown in Figure DS-4.

Figure DS-4. The Rising Costs of SMRs Marketed in the United States[27]



There are several points to emphasize about Figure DS-4. First, the estimated cost of the NuScale SMR increased on a $/kW basis by 138% between 2020 and 2023, and the estimated cost of the X-Energy SMR increased by 72% between 2021 and 2024.

The most recent cost estimate I could find for the BWRX-300 SMR was in a TVA IRP filing, and it includes only the project's estimated overnight cost—escalation and financing costs are not included. Therefore, the estimated all-in cost of the project must be much higher than shown in Figure 4.

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[27] *See, e.g. id.*; X-Energy statements to U.S. Congress and filing with the State of Washington; public statements by Bill Gates; TVA's 2025 Integrated Resource Plan filing.

Q. Have you seen any claims about the cost of SMRs other than those in Figure DS-4?

A. Yes. When Westinghouse announced its AP300 SMR, it claimed that the per-kW cost of its SMR will be ~$1 billion.[28] If achieved, this would mean that the per-kW cost of an AP300 would be 84% lower than the actual cost of the Westinghouse AP1000 reactors recently completed at the Vogtle Nuclear Project in Georgia. This figure simply cannot be taken seriously, even if Westinghouse is focusing on only its share of the overnight cost of an AP300 SMR.

Q. Do you expect that the high construction commodity prices and supply chain competition that led to the cancellation of the NuScale SMR and the rising costs and schedule delays experienced by other SMR designs will continue for the foreseeable future?

A. Yes. The world is planning massive infrastructure investments in renewable resources, clean hydrogen, electrification and storage, and nuclear projects, to address climate change. At the same time, industrialization efforts are underway in numerous areas of the globe and the oil and gas industry is planning expanded development efforts, as well. Given all of this, plus our current federal government's desire to impose tariffs on goods from other trading partners, I expect that although commodity prices may go up and down, the long-term trend

[28] Catherine Clifford, *Westinghouse announces a new small nuclear reactor—a notable step in the industry's efforts to remake itself*, CNBC, May 4, 2023, https://www.cnbc.com/2023/05/04/westinghouse-announces-a-small-nuclear-reactor.html.

will be upward. Therefore, anyone looking to build or buy power from an SMR should expect construction costs will continue to rise due to higher commodity prices and supply chain competition.

As I explained in expert testimony to the Georgia Public Service Commission in December 2008, in which I warned, correctly it has turned out, that the then-estimated cost for the Vogtle Nuclear Project was far too low.[29]

> The increased estimated costs for today's new generation of nuclear plants are due, in large part, to a fierce worldwide competition for the resources, commodities and manufacturing capacity needed in the design and construction of new power plants. This competition has led to double-digit annual increases in the costs of key plant commodities such as steel, copper, concrete, etc. At the same time, as explained in an article in the Wall Street Journal, new nuclear power plants are being proposed "amid a growing shortage of skilled labor; and against the backdrop of a shrunken supplier network for the industry."
>
> The worldwide demand also is straining the limited capacity of EPC (Engineering, Procurement and Construction) firms and equipment manufacturers. The limited number of manufacturers and suppliers could cause bottlenecks in construction if, as expected, there are multiple orders for new power plants in the U.S. and abroad.
>
> . . .
>
> The worldwide competition for power plant design and construction resources, equipment and commodities means fewer bidders for work, higher prices, earlier payment schedules, and longer delivery times. . . . The demand and cost for both on-site construction labor and skill manufacturing labor also have escalated.

[29] As I explain later in this testimony, for the two-reactor, Vogtle Nuclear Project, built between 2013 and 2024, the actual construction cost was approximately $22 billion higher than the $14 billion cost estimated prior to the start of construction.

> Moody's has summarized the increased risks associated with the international competition for power plant resources as follows:
>
> > Dramatic increases in commodity prices over the recent past, exacerbated by a skill labor shortage have led to significant increases in the over-all cost estimates for major construction projects around the world. . . . As noted previously, labor is in short supply and commodity costs have been extremely volatile. Most importantly, the commodities and world wide supply network associated with new nuclear projects are also being called upon to build other generation facilities, including coal as well as nuclear, nationally and internationally. Nuclear operators also are competing with major oil, petrochemical and steel companies for access to these resources, and thus represent a challenge for all major construction projects.[30]

Other than replacing "coal" with "renewable wind solar, and storage," I think this applies directly today and sums up the risk of higher costs for today's proposed SMR projects.

Q. Is it reasonable to expect that the costs of building SMRs will continue to go up beyond the increases shown in Figure DS-4?

A. Yes. It is reasonable to expect that the costs of building SMRs, including both those included in Figure DS-4 and the other designs currently being marketed in the United States, will continue to go up in coming years. In fact, the supply chain for SMRs is currently facing extraordinary stress from the current trade war

[30] Ga. Pub. Serv. Comm'n, Docket No. 27800-U, David Schlissel Direct Test. 13–15 (Dec. 19, 2008), https://schlissel-technical.com/docs/testimony/testimony_26.pdf (internal footnotes and citations omitted).

started by the United States.[31] Although this same stress will affect other generating options, such as renewables, it is likely to have a far more significant impact on extremely capital-intensive nuclear projects.

The experience of other reactor projects has repeatedly shown that further significant cost increases and substantial schedule delays should be anticipated at all stages of project development. After all, none of these SMRs have started construction yet, are under construction, or even been licensed by the NRC, as I noted earlier. This means that there may be as long as another fifteen-year time period during which developers will be exposed to the risks of rising costs and schedule delays.

Q. Have the SMRs included in Figure DS-4 also experienced schedule delays?

A. Yes. In 2008, NuScale told the NRC that an SMR could be producing electricity by 2015-2016.[32] But by 2018, power generation from NuScale's first power module at its initial SMR was pushed back to 2026, with the remaining modules to follow in 2027. These dates were subsequently delayed to mid-2029 and June 2030, before the project was cancelled in 2023.

The Xe-100 reactor was first planned to be online by 2027, but this has been delayed with what is being called "Substantial Completion" now scheduled

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[31] Shannon Cuthrell, *Inflation-Ridden Supply Chains, Interest Rates Dampen SMR Development*, EEPower. July 13, 2023, https://eepower.com/tech-insights/inflation-ridden-supply-chains-interest-rates-dampen-smr-development/.

[32] *See* David Schlissel & Dennis Wamsted, Inst. for Energy Econs. & Fin. Analysis, *NuScale's Small Modular Reactor* (2022), https://ieefa.org/wp-content/uploads/2022/02/NuScales-Small-Modular-Reactor_February-2022.pdf.

for September 2033 and no mention of when the reactor will be in commercial service.

Q. Is it reasonable to expect that current SMRs will continue to experience schedule delays?

A, Yes.

Q. Did the first generation of reactors built in the United States also experience cost increases and schedule delays like these SMRs?

A. Yes. The history of the U.S. nuclear industry in one of dramatic cost and schedule overruns. For example, a 1986 DOE study compared the estimated versus actual overnight costs of 75 reactors that started construction between the years of 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.[33]

I would note that this study actually understated the cost overruns for the reactors built in the United States during this period in two ways. First, the overnight costs used for the study did not include escalation or financing costs. In addition, a number of the most expensive reactors built during that period were not included because of their construction start or estimated completion dates; or in others cases, the actual costs of some included reactor projects were not included because they increased at a later date. The same study found that on

[33] Energy Info. Admin., DOE, *An Analysis of Nuclear Power Plant Construction Costs* (1986), https://www.osti.gov/biblio/6071600.

average, the time to build each of these reactors was 9.7 years, or nearly five years longer than had been projected when construction was started.

Q. How long do the DOE and the PIESAC report currently assume it will take to build a new SMR?

A. Both the DOE and the PIESAC report assume that a new SMR can be in commercial service within five years of its first nuclear concrete date. Consequently, they ignore the experience of the earlier generation of reactors.

Q. What did the nuclear industry do after the costs of the first generation of reactors had gone up so much and the projects had had such long construction durations?

A. The industry marketed new reactor designs that they said would lead to less expensive reactors that could be built faster than the earlier ones. For example, Westinghouse touted that its new AP1000 reactors would benefit from modular construction, in terms of both shorter construction time and lower costs. The "1000" in the reactor's name refers to the fact that it was expected to produce about 1000 MW of power. In fact, Westinghouse's promotional materials for AP1000 reactor said it could be built in just three years (from first concrete to fuel loading) because the components would be factory-built and shipped to the site for assembly. A 2009 article reported that the "AP1000 has been designed to make use of modern, modular construction techniques," and "modularization allows construction tasks that were traditionally performed in sequence to be completed in parallel."[34]

Q. Did this lead to less expensive reactors?

A. No. In fact, it would be a severe understatement just to say that the claimed benefits for the new reactor designs and modular construction were not realized. In the first decade of this century, over 20 new reactor projects were proposed around the United States, but only two two-unit projects, both of which planned to use the new Westinghouse AP1000 design, actually began construction. These were the Vogtle Nuclear Project in Georgia and the Summer Project in South Carolina. However, only Vogtle was completed.

The estimated cost of the Vogtle project was $14.1 billion at the time construction began in March of 2013. At that time, Southern Company, which is the lead owner of the project, projected that the first new unit would be online in 2016 and the second in 2017. By the time both units were in commercial operation in April 2024, the Vogtle project had experienced a cost overrun of about $22 billion and a schedule overrun of ~6 years. Westinghouse had declared bankruptcy in 2017 due to problems with the project and the dramatically rising costs. Its owner, Toshiba, had signed an agreement to pay $3.7 billion of the project's cost overrun as part of a settlement with Vogtle's owners.

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[34] James M. Hylko, *Plant Vogtle Leads the Next Nuclear Generation*, Power Mag., Nov. 1, 2009, https://www.powermag.com/plant-vogtle-leads-the-next-nuclear-generation/.

As a result, the actual cost of building the two-reactors at Vogtle project was 157% higher than had been initially estimated. By the time the second unit was online at the end of April 2024, it had taken eleven years, or six to seven years longer than originally estimated, to build the two units.

The Summer project in South Carolina suffered similar cost overruns, with its estimated cost growing from an initial $11 billion to an estimated $25 billion by the time the project was cancelled in 2017. Nine billion dollars had been spent on the Summer Project by the time it was cancelled in 2017.

Q. Did modular design and the installation of factory-built modules work well at Vogtle?

A. No. It is an understatement to say that modular construction and the use of factory-built modules did not work as well at either the Vogtle or the Summer projects, as Westinghouse had claimed they would in its marketing materials.

Q. What sorts of problems were encountered with the use of modular design and the assembly of factory-built modules at Vogtle and Summer?

A. Testimony by the nuclear engineers retained by the Georgia Public Service Commission to closely monitor the Vogtle project, NRC inspection reports, and articles in the media—including one based on an interview with the former procurement quality-assurance manager at Shaw Nuclear, the company at whose Louisiana factory modules and submodules for the Vogtle & Summer projects were fabricated—all describe how problems with modularization and use of factory-built projects substantially delayed and increased the cost of both projects.

These problems included such failures as unsatisfactory module design, fabrication, and assembly of modules; the failure to fabricate high quality modules at the production rate needed to support the project; late delivery of modules to the site; the need for rework at the site; poor quality assurance/quality control; the use of the wrong welding materials; missing signatures that held up import and work; and coverups of damaged sections.[35]

One 2017 article from Reuters examined "How two cutting edge U.S. nuclear projects bankrupted Westinghouse" and concluded:

> [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.[36]

Another article similarly warned:

> If historians examine why the nuclear renaissance fizzled, they could cite Westinghouse's promise the AP1000 reactors needed "a short 36-month construction schedule" from first concrete to core load. Or they could note that Shaw was unprepared for what it faced from its partner Westinghouse and the

[35] *See, e.g.*, Ga. Pub. Serv. Comm'n, Docket No. 29849, Steven Roetger & William Jacobs Direct Test. (Oct. 27, 2023), https://psc.ga.gov/search/facts-document/?documentId=216172; Ga. Pub. Serv. Comm'n, Docket No. 29849, William Jacobs Direct Test. (May 30, 2012), https://psc.ga.gov/search/facts-document/?documentId=142513.

[36] Tom Hals & Emily Flitter, *How two cutting edge U.S. nuclear projects bankrupted Westinghouse*, Reuters, May 2, 2017, https://www.reuters.com/article/world/how-two-cutting-edge-us-nuclear-projects-bankrupted-westinghouse-idUSKBN17Y0C7/.

> nuclear construction industry. The glittering promise that modular design would erase much of the risk of nuclear construction turned out to be just that, a glittering promise. The V.C. Summer and Plant Vogtle projects, instead of forming the basis of a nuclear renaissance, delivered a body blow to U.S. nuclear construction as devastating as any of the disastrous nuclear projects that are already in the history books.[37]

Q. Do you believe that the same warning should be given to today's rush to undertake, approve, or give large subsidies to proposed SMRs?

A. Yes. I fear the quote "Those Who Cannot Remember the Past Are Condemned to Repeat It" from George Santayana will be how future generations will describe today's mad dash to push expensive SMRs with untested designs by those who either forget, or choose to ignore, the decades-long history of the nuclear industry's broken promises.

Q. After the experience at Vogtle and Summer, what do the nuclear industry and its supporters now claim about the new SMRs now being marketed?

A. The marketing pitch is pretty much the same, except that the primary emphasis has been placed on SMRs, although Westinghouse is still marketing its AP1000 reactor design.

For example, Westinghouse now claims that "[t]he Westinghouse AP300 SMR delivers on the promises of small modular reactors: smaller scale, modular construction for efficient build schedules, state-of-the-art safety and reliability."[38]

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[37] Richard Korman, *Witness to the Origins of a Huge Nuclear Construction Flop*, Eng'g News-Record, Nov. 1, 2017, https://www.enr.com/articles/43325-witness-to-the-origins-of-a-huge-nuclear-construction-flop.

[38] AP300™ SMR, Westinghouse, https://westinghousenuclear.com/energy-systems/ap300-smr/ (last visited Apr. 17, 2025).

The industry and its supporters also claim that building lots of SMRs with the same design will lead to declines in construction costs and the per-MWh cost of power—that is, there will be what is called a positive learning curve that will lead to cost reductions.

Q. Have you seen any evidence that there has been such a learning curve in the building of nuclear power plants in the United States?

A. No. The existence of a positive learning curve that will bring down the high cost of building SMRs over time is just an assumption, if you will, an unproven claim, by supporters of nuclear power and the media without offering any real evidence. It certainly hasn't happened in the United States, and credible evidence raises significant doubts about whether it has happened elsewhere.

Q. Have you looked for any evidence of such a positive learning curve for new nuclear reactors?

A. Yes. I have looked at published academic analyses. I also conducted my own analysis to explore whether the construction durations of recent reactors with new designs reveal a positive learning curve.

Q. What evidence have you found that supports the claim that there will be a positive learning curve that will reduce the cost and time it takes to build future SMRs?

A. The little evidence I have seen cited in support of a positive learning curve for new reactors has been based on overnight cost estimates that, as I've noted above, exclude escalation and financing costs. However, as I will show below, when escalation and financing costs are included, the estimated costs of future reactors actually increase, rather than decline.

Q. Are you saying that the use of overnight costs is inherently a bad idea?

A. Not at all. During my career, I have seen overnight costs used by many utilities and experts in two general ways. First, utilities and experts use overnight costs for the initial screening of energy technologies, to determine which technologies should be included in more detailed modeling analyses. And second, utilities and experts use overnight costs as inputs to those more detailed analyses. In that case, the company's financial models typically add in the escalation and financing costs of the different generation alternatives.

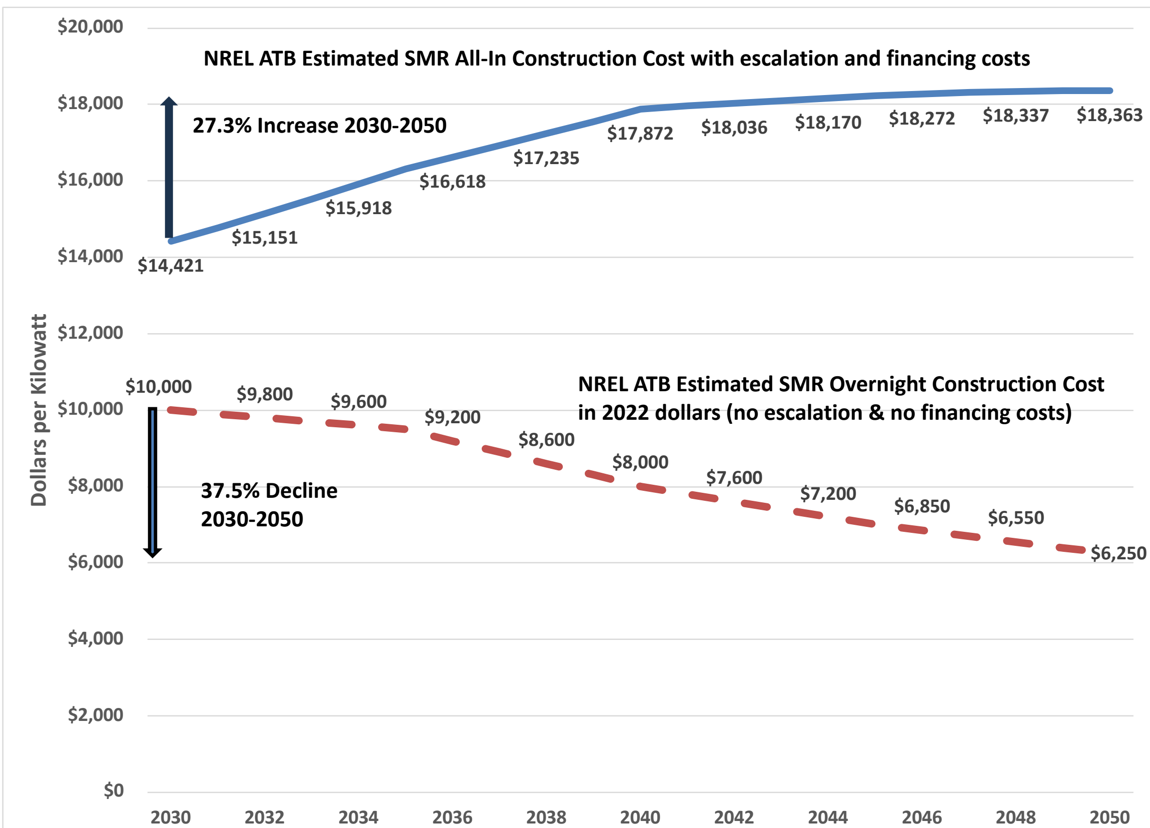
What concerns me is the use of overnight costs by proponents of new reactors in the public debate, or the media, without explaining their limitations. I fear this misleads the public, the media, and decision-makers about what it will actually cost to build those new reactors.

Similarly, using constant-year dollars, with financing costs, can be useful when comparing the actual cost of building reactors in the past to the projected costs of proposed future reactors (including, but not limited to, SMRs).

Q. Can you provide an example of what you mean when you say the use of overnight costs can be misleading?

A. Yes. As shown in Figure DS-5 below, the National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline (ATB) analysis assumes that the overnight capital cost of an SMR built in 2030 would be $10,000/kW, falling to $6,250 for an SMR built 2050.[39] At first glance this looks very good for reactor supporters, as it represents a 37.85% decline in construction cost in just 20 years. However, when you add NREL's assumed 2.5% annual escalation rate and its estimated financing costs to the overnight cost, the estimated construction cost of the SMR would increase by 27.3% between 2030 and 2050, not decline.

Figure DS-5. SMR Supporters Can Mislead the Public and Decision Makers By Focusing on Estimated Overnight Costs Instead of All-In Costs[40]



[39] *See Annual Technology Baseline, Nuclear*, NREL, https://atb.nrel.gov/electricity/2024/nuclear (last visited Apr. 17, 2025).
[40] *Id.*

Q. Have you seen any evidence that the nuclear industry has not yet achieved a positive learning curve that will assuredly make future SMRs less expensive and faster to build?

A. Yes. As noted above, the U.S. nuclear industry has never shown a positive learning curve. Instead, it has repeatedly shown a negative learning curve where the cost of new reactors continued to rise.

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.[41] In fact, a peer-group reviewed analysis found that despite its high degree of standardization, between 1974 and 1984, the real costs of building reactors in France increased by approximately 5% per year, and that this increased to 6% per year for reactors built between 1984 and 1990.[42]

Q. Did the French achieve any reductions in the time it took to build new reactors during this nuclear scale-up?

A. Based on mean construction time data in Table 1 of "The costs of the French nuclear scale-up: A case of negative learning by doing," the answer is no.[43]

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[41] Arnulf Grubler, *The costs of the French nuclear scale-up: A case of negative learning by doing*, 38 Energy Pol'y 5174 (2010), https://www.sciencedirect.com/science/article/abs/pii/S0301421510003526.
[42] *Id.* at figs. 8 and 12.
[43] *Id.* at tbl. 1.

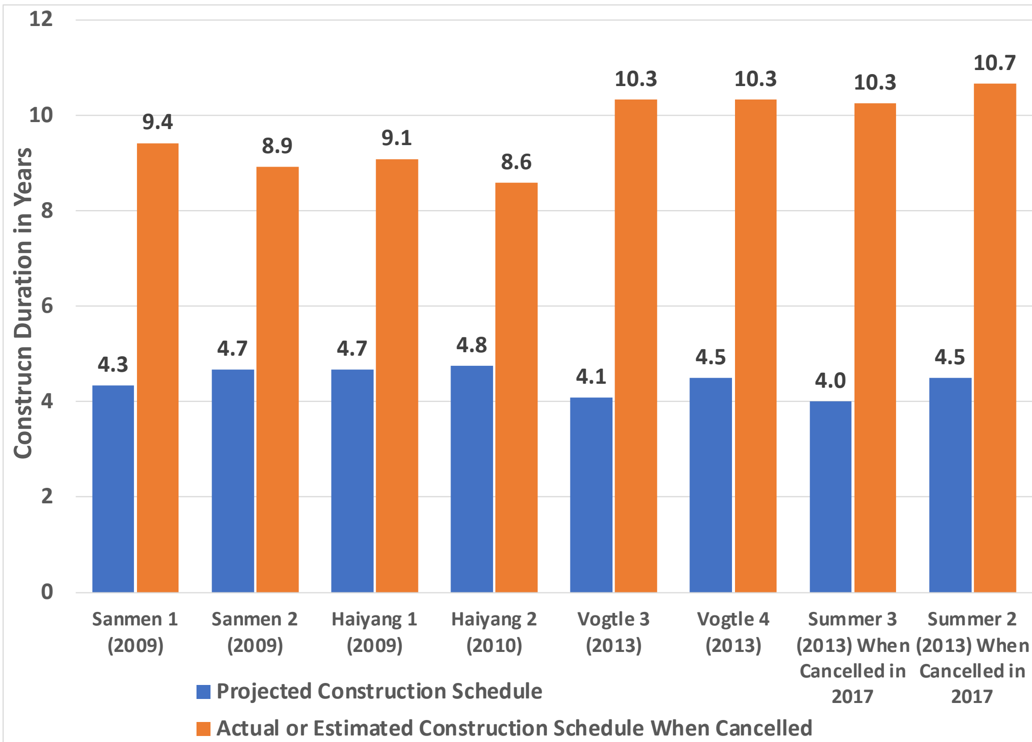
Average French reactor construction times increased over the years. They did not shorten.

Q. Have you looked for any evidence of a positive learning curve in building recent reactors?

A. Yes. It is difficult to compare construction costs between reactors built in different countries, due to different commodity prices, labor costs, currency conversion rates, and accounting practices. Therefore, I have not attempted to compare the costs of building new reactors with new designs around the world. Rather, I look at the trends in the costs of building reactors in other countries. That is, whether the estimated costs are going up, and if they are, by how much. However, I have looked for evidence of a positive learning curve in the data on how long it has taken to build subsequent units with the same reactor design. This is based on my assumption that if there is a positive learning curve for costs, it also should be reflected in reduced time to build each new reactor design.

Consequently, I have analyzed how long each has taken to construct the eight reactors in the world with Westinghouse's AP1000 design, the eight reactors with Westinghouse's AP1400 design, and the five EPR reactors designed by Ariva/EDF. As can be seen in Figures DS-6, DS-7, and DS-8, there is no significant learning curve achieved with any of these recent reactor designs. Please note that the year included in the labels for the reactors in each chart is the year in which nuclear construction began at each reactor. The reactors are then presented along the x-axis with the earliest next to the y-axis. Thus, the further to the right, the later the start of nuclear construction for each reactor.

Figure DS-6. Westinghouse AP1000 Estimated vs. Actual Construction Schedule Durations[44]



[44] Source: Publicly available data on estimated construction schedules and actual data from IAEA PRIS database, https://pris.iaea.org/PRIS/WorldStatistics/OperationalReactorsByCountry.aspx.

Figure DS-7. Westinghouse AP1400 Reactor Estimated vs. Actual Construction Schedule Durations[45]

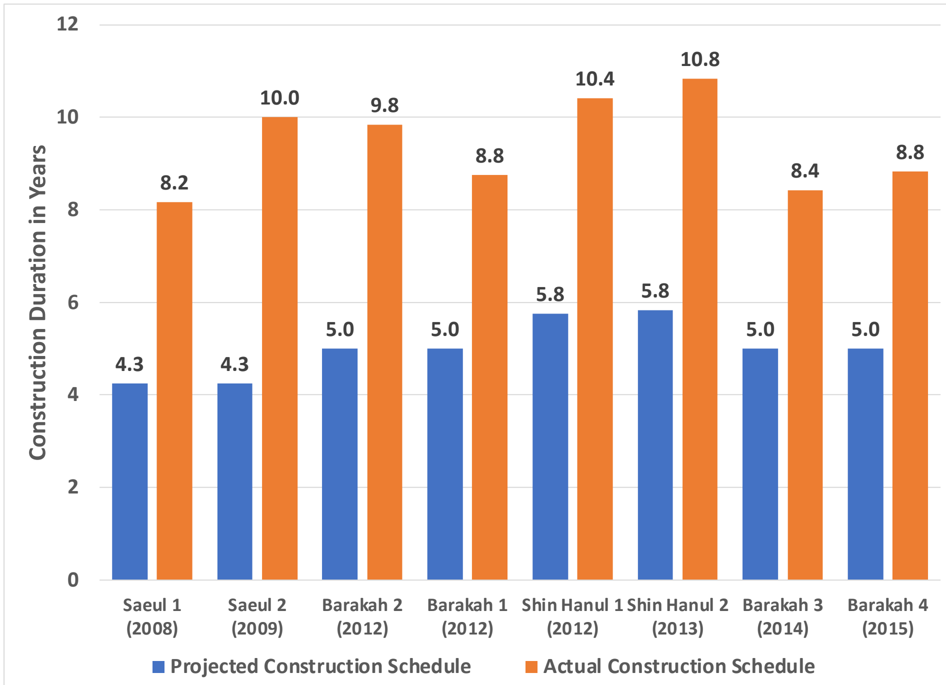
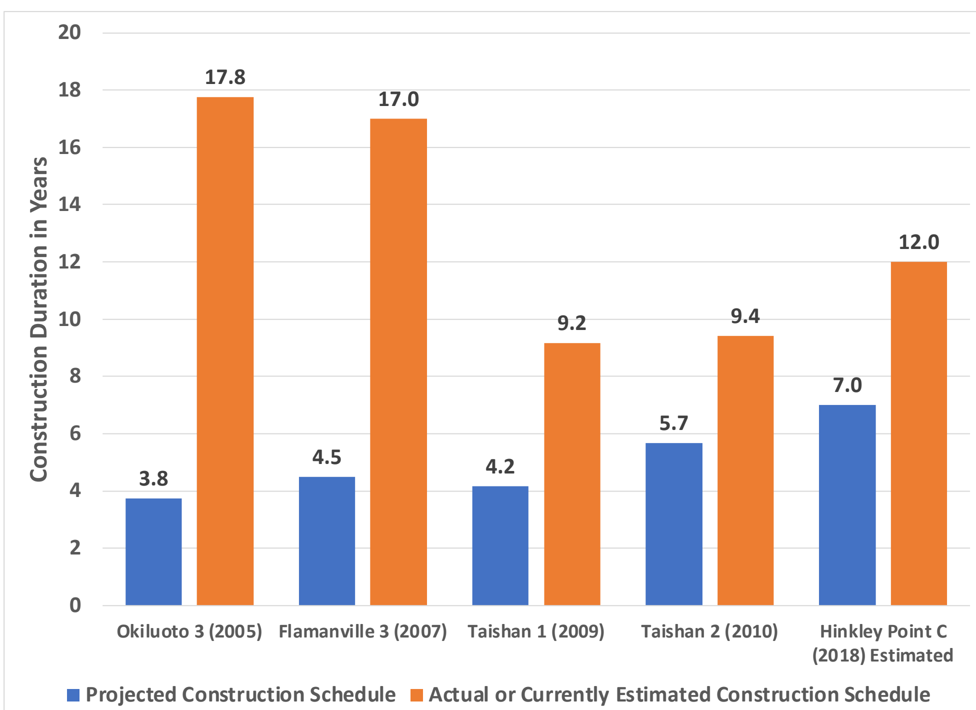


Figure DS-8. EPR Actual and Estimated Construction Schedule Durations[46]



Q. What are the key findings shown in Figures DS-6 to DS-8?

A. The overall key findings of my analysis are (1) almost all of these reactors with new designs were initially projected to take between 4 and 5.5 years to build, but experienced significant schedule overruns; and (2) none of these three new reactor technologies has shown any evidence of a positive learning curve—that is, there was no meaningful reduction in the time to took to build new reactors over time. This is even true for the four AP1400 reactors that were built a year apart at the same site in the United Arab Emirates by South Korea.

Another interesting observation is that the Vogtle Nuclear Project in the United States was not the first in the world to use Westinghouse's AP1000 design. Despite being the 5^{th} and 6^{th} reactors with Westinghouse's AP1000 design that were under construction, as I've discussed, the Vogtle units experienced significant problems that led to a 157% cost overrun and more than six years of schedule overruns. If there had been a positive learning curve, construction at Vogtle should have taken less time than at the first four AP1000 reactors. But it clearly didn't.

Q. What is the significance of the substantially longer construction schedules experienced at all of the reactors with new designs shown in Figures DS-6 to DS-8?

A. Quite simply, other things being equal, a longer construction schedule will mean higher total financing costs for a project. As the DOE has explained in an illustrative example: "For illustrative purposes, for $100 in overnight capital costs, 5 years of construction would lead to $22 in capitalized interest at 5% interest rates; 10 years would lead to $50. Shortening construction duration is an important lever for [reducing costs of future SMRs]."[47]

Q. If indeed there is a positive learning curve for building SMRs, as nuclear proponents claim, how fast would the costs of building new SMR be expected to decline?

A. No one can answer that question. Any positive learning curve achieved in building SMRs will depend on how many of each design are built. The IAEA estimates that there are about 80 different SMR designs being proposed and marketed worldwide, making it highly uncertain how many of each design will be constructed. Too few and there are likely to be any cost savings over time, and there may be no economic justification for modular construction in a factory.

Q. Does the United States currently have a sufficiently large nuclear infrastructure to build and bring online more than even a few SMRs at a time?

A. No. As the DOE has reported:

> **The US lacks nuclear and megaproject delivery infrastructure**. 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

[47] DOE, *Pathways to Commercial Liftoff: Advanced Nuclear* 34 (2024), https://liftoff.energy.gov/wp-content/uploads/2024/10/LIFTOFF_DOE_Advanced-Nuclear_Updated-2.5.25.pdf.

> 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.[48]

Q. What is a megaproject?

A. In my experience, a megaproject is a project projected to cost billions of dollars or more, and that is expected to take several years or longer to complete.

Q. Would new SMRs be effective tools for addressing climate change?

A. No.

Q. Please explain why not.

A. There are several reasons that SMRs won't be good tools for fighting climate change:

1. SMRs will be too expensive and take too long to build. Faster and less expensive renewables with storage options can be online much sooner.
2. SMRs may compete with, not complement, renewable resources.
3. SMRs likely will be threatened by the effects of climate change.

Q. Are the concerns about the high cost of new reactors and how long it will take to build them limited to those outside the nuclear industry?

A. No. I have seen similar concerns from veterans of the nuclear industry, as well as potential SMR utility customers. For example, Donald Grace has more than 50 years of experience in nuclear and fossil fuel plants and served as the Georgia Public Service Commission's Plant Vogtle Construction Monitor from 2027 to

[48] *Id.* at 71.

2024. Mr. Grace shared the following observations and concerns in a recent Commentary in Power Magazine:

> The necessary assumptions for reducing nuclear capital costs include multiple plant orders (to spread the common costs among multiple plants), a factory like production line building of common modules to better assure quality and reduce costs, and the availability of nuclear construction labor and expertise. These assumptions are not new, but in the past always changed. . . .
>
> These same original assumptions were made at the start of Vogtle Units 3 and 4. This time, with reduced natural gas prices and decreased future demand forecasts, of the originally intended 14 AP1000 reactors, only Vogtle was pursued to completion. When the pipeline of nuclear reactor orders dried up, it resulted in cancellation of the modular facility and high costs drove the construction contractor, Westinghouse, into bankruptcy. Those factors, coupled with limited nuclear construction labor and expertise, meant that Vogtle's construction costs exceeded even the worst projections. <u>Also, even if one could better control the environment within which the plants are to be constructed, given the high cost of the inherent design, it is questionable as to what percentage cost reduction would be achievable and whether that would be sufficient to make nuclear cost competitive with other energy generation choices</u>.
>
> In going forward with nuclear, there is increased emphasis on building smaller plants, again having multiple orders and a factory like facility for manufacturing modules to support the multiple orders. However, lessons learned from the past would show that economies of scale from larger plants could be lost. This was the case when Westinghouse had previously cancelled the AP600 plant in favor of the larger AP1000 design. These same economies of scale would most likely be lost not only with respect to construction costs, but also with respect to operations costs. This is due largely to the required large staff to protect and operate a nuclear plant.
>
> <u>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</u>

> evidence points to more affordable, faster, and readily available near-term alternatives.[49]

Similarly, NextEra Energy's CEO, John Ketchum, recently expressed concerns about SMRs to Utility Dive, even as the company is working on restarting a retired reactor in Iowa:

> Despite the recent fervor among tech companies and investors about nuclear energy, Ketchum held that renewables and storage will likely play a greater role in meeting new energy demand for at least two decades to come.
>
> . . .
>
> But Ketchum said he was "not bullish" on the newer SMR technology. NextEra has an in-house team dedicated to SMRs, he said, but so far they have not drawn favorable conclusions about the technology.
>
> "A lot of [SMR equipment manufacturers] are very strained financially," he said. "There are only a handful that really have capitalization that could actually carry them through the next several years."
>
> Ketchum also raised questions about the availability of nuclear fuel in the United States, and noted that SMRs remain "very expensive" even as the cost of renewable energy continues to fall.[50]

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[49] Don Grace, *What Was Learned from Building New Nuclear Reactors?*, Power Mag., Apr. 1, 2025, https://www.powermag.com/what-was-learned-from-building-new-nuclear-reactors/ (emphases added).

[50] Emma Penrod, *NextEra CEO 'not bullish' on SMRs as company assesses potential Duane Arnold restart*, UtilityDive, Oct. 24, 2024, https://www.utilitydive.com/news/nextera-ceo-not-bullish-on-smrs-as-company-assesses-potential-duane-arnol/730855/.

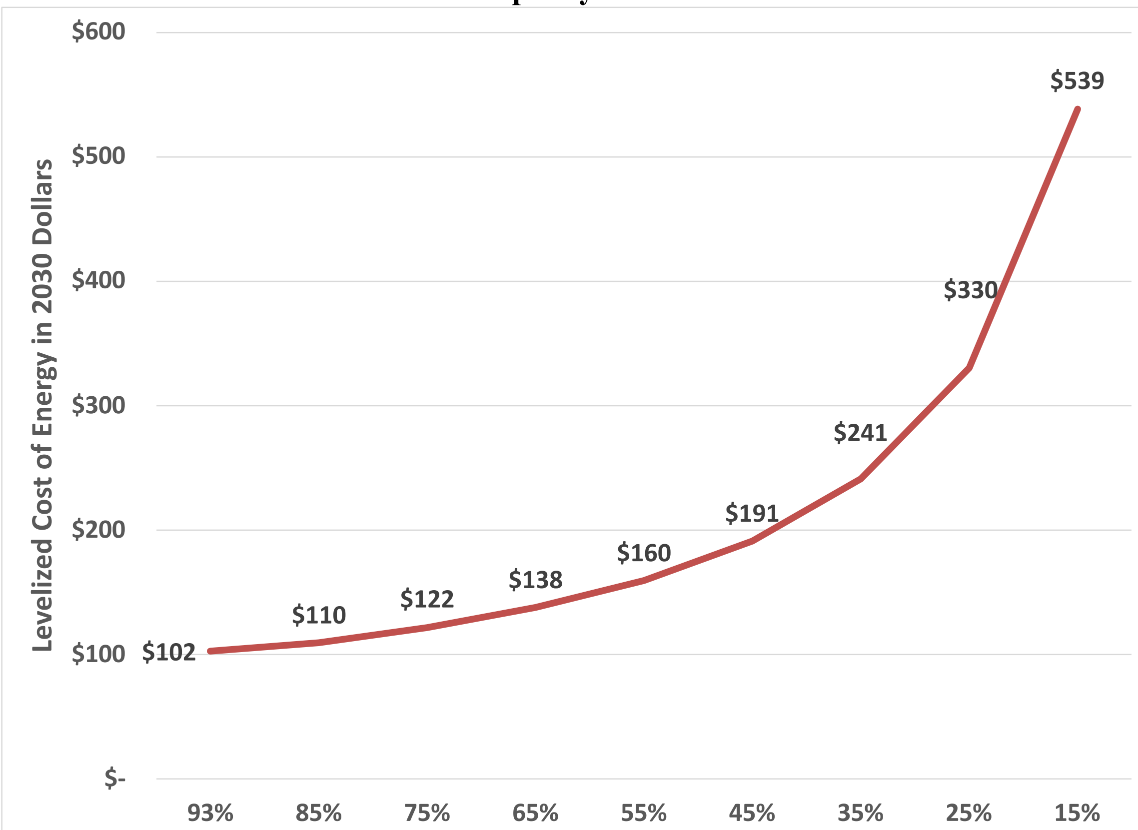
Q. Why do you say that SMRs will not complement renewable resources when supporters say that will be one of SMRs' major benefits?

A. I've seen SMR proponents claim that the reactors will achieve very high annual capacity factors, usually somewhere around 93% or 95%. I accept it might be technically possible to cycle an SMR up and down in response to demand on the grid and the availability of intermittent wind and solar resources. However, it is simply an impossible task to achieve both a high capacity factor and operate a SMR flexibly, in a load following manner, by ramping up and down depending on how much the wind is blowing and/or the sun is shining.

Q. How would cycling an SMR affect its average power cost?

A. Because such a large portion of its costs are fixed, the more it is cycled, and its capacity factor declines, the higher its average cost of power, as illustrated by the example in Figure DS-9.

Figure DS-9. The Average Cost of the Power from an SMR Goes Up as the Plant's Capacity Factor Goes Down[51]



In order to achieve such a high capacity factor, the SMR must basically run at 100% power in all the hours that it is online and not experience extended outages during its multi-decade long operating life. Consequently, the owners of an SMR would probably prefer to operate as close to full power for as many hours of the year as possible, because that would increase its profitability.

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[51] *Annual Technology Baseline, Nuclear*, NREL, https://atb.nrel.gov/electricity/2024/nuclear (last visited Apr. 17, 2025).

Q. Could cycling an SMR harm the plant?

A. A paper written by personnel from NuScale, UAMPS, and Energy Northwest identified several potentially serious issues associated with the frequent cycling of the NuScale SMR. The paper noted that "[r]outine thermal and operational cycling will likely cause components to degrade faster and may result in increased maintenance and lower module availability."[52]

The paper also noted:

> [L]oad following with a nuclear plant has several operational and economic impacts. Reactor operations are the least impacted when changes in electrical output are accomplished by closing or operating 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, this resulting in increased maintenance and equipment replacement.[53]

The paper concluded, "Ultimately, it will be economics, policy mandates and regulatory requirements that drive the decision regarding the extent of load-following by the nuclear plant in an integrated nuclear-renewable environment."[54]

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[52] D.T. Ingersoll et al., *Can Nuclear Power and Renewables be Friends?*, Int'l Cong. on Advances in Nuclear Power Plants 2015 Proceedings at 8 (2015), https://international.anl.gov/training/materials/BL/NuScale-Integration-with-Renewables_ICAPP15.pdf (emphasis added).
[53] *Id.* at 6–8.
[54] *Id.* at 8.

Q. If it is more profitable to run the SMR at full power for as many hours of the year as possible, is it possible that an SMR could compete with renewables for available transmission space?

A. It might be that SMRs and renewables may prove to be not such close friends after all. This would especially be the case in areas like Pueblo, which is home to large amounts of solar capacity with almost zero variable costs.

Q. Are there any risks from long SMR construction times in addition to higher project capital costs?

A. Yes. The risk of projects with long construction lead times is that it will be difficult to change course if costs rise faster than expected, the demand they are proposed to serve doesn't materialize, or the costs of alternatives continue to decline sharply. This is what led to the cancellation of over 100 proposed coal plants in the years 2005–2015. Expected demand did not develop, costs went up, and the cost of natural gas cratered as a result of fracking.

Something similar could occur today if all of the currently projected demand growth from data centers and artificial intelligence does not materialize. It is better to add capacity that can be added without long-term lead times, like solar + storage facilities. That way, utilities and their ratepayers would have the flexibility to avoid being trapped in projects that are increasingly expensive and/or not needed as much as was expected when they were proposed.

Q. As you have testified, nuclear proponents have cited a number of purported benefits from constructing a significant number of SMRs with the same design. Are there any potential problems with doing that?

A. Yes. Building many copies of the same SMR design does seem like a good idea, but there are potential problems. First, as I testified earlier, there could be higher construction costs and schedule overruns due to increased competition for design and construction resources and commodities, or access to manufacturing space at a modular fabrication plant or the plants of the suppliers of major project equipment.

Second, another important issue that has received too little attention in the discussion of SMR commercialization is the potential for systemic flaws as a result of building 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 company's fleet of 787 Dreamliners. But it could also apply to Boeing's more recent experience with a poorly designed feature in its 737 MAX aircraft that led to two critical crashes, and several years of the 737 MAX air fleet needing to be grounded until the problem was identified and fully corrected. Similarly, an unexpected and unidentified design flaw discovered in a key component of a highly standardized SMR could lead to extended and expensive outages, repairs, and design changes. But taking an airplane back to Boeing for those repairs and design changes is relatively easy, while taking an SMR back to the factory would be extremely difficult, if not impossible.

The potential risk that a problem identified in an SMR will affect the costs, and maybe the operation, of other SMRs with the exact or similar standardized design, is not merely hypothetical. Problems have cropped up during the operation of reactors around the world due to materials choices and design decisions made before these 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.[55] These replacements were the result of the denting and wall thinning of large numbers of steam generator tubes that had been made from heat-treated Alloy 600. Five additional U.S. PWRs were shut down early due to steam generator cracking. Reactor developers had decided on the general use of this material for fabricating steam generator tubes years before they became operation.

Similarly, a decision on the material to be used in key safety-related piping in boiling water reactors (BWRs) led to significant pipe cracking from intergranular stress corrosion cracking. As a result, nine U.S. BWRs completely replaced their full recirculation system piping with pipes made from lower carbon steel. Another three BWRs replaced the heavily cracked sections of their

[55] *Nuclear Power Reactors*, World Nuclear Ass'n, https://world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/nuclear-power-reactors (last visited Apr. 17, 2025).

recirculation system piping.[56] 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.

I'm not arguing that new SMRs will have these very same issues. In fact, I expect that the design and material decisions made for SMRs will reflect remedial measures taken for problems experienced at existing reactors. My point is broader in that a problem with one SMR design might have serious cost and operational repercussions at many other SMRs with the same or a similar standardized design.

Q. Will the Inflation Reduction Act's nuclear subsidies reduce the cost of building new SMRs?

A. No. The Clean Energy Investment Tax Credit (ITC) in the Inflation Reduction Act (IRA) will not reduce the overall cost of building a new reactor, except perhaps for a reduction in some financing costs. However, what the tax credits will do is transfer a significant portion of the cost of building a new reactor from ratepayers of companies like PSCo to taxpayers.

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[56] J.R. Strosnider, Jr. et al., U.S. NRC, *Pipe Cracking in U.S. BWRs: A Regulatory History* (2000), https://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1719/index.html.

Q. Have you compared the estimated costs of power from an SMR with the cost of power from renewable resources?

A. Yes. Using the data from NREL's Annual Technical Baseline (ATB) Excel file/data, I have compared the estimated Levelized Cost of Energy (LCOE) from an SMR with the costs of power from wind, solar, and solar + storage resources.

Q. Did you assume that an SMR built in the Pueblo area would be eligible for the Clean Energy ITCs in the IRA?

A. Yes. I assumed that an SMR sited in Pueblo would be eligible for the full 50% Clean Energy ITC subsidy in the IRA. This would include the base 30% ITC that projects which meet the PWA (prevailing wage and apprenticeship requirements) are eligible for. I also assumed that Pueblo would be eligible for an additional 20% of ITC subsidies. The first would be a 10% ITC due to being a fossil energy community, and the second additional 10% would reflect that the SMR project would meet domestic content requirements.

Q. What are your other key assumptions?

A. Consistent with the discussion above, I assumed there would be no positive learning curve. I also assumed, to be conservative and consistent with the PIESAC report, that a new SMR in Pueblo would take about five years of pre-construction planning and another five years to build. This would mean that an SMR might not be online until 2035 or later. I did this although I think it likely would take longer than ten years from today to plan, design, license, and build a new SMR in a place like Pueblo.

Q. What did you assume about the cost of a new SMR?

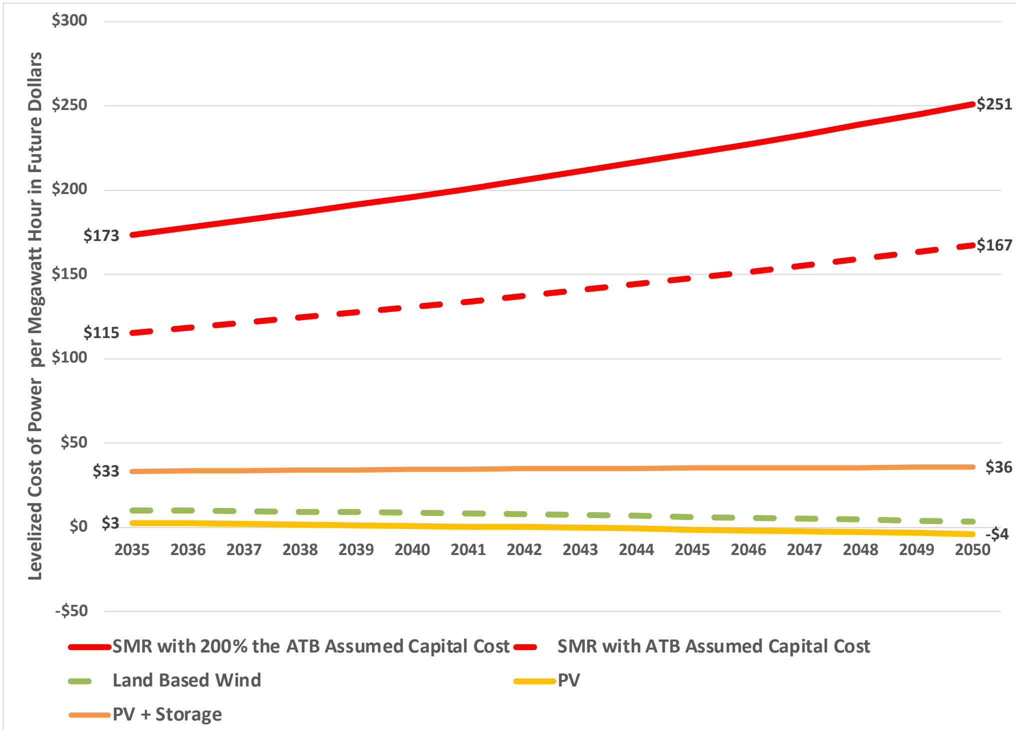
A. Although I think this is probably too conservative, by which I mean too low, the low end of my projected SMR LCOE range is based on the assumption in the 2024 NREL ATB that the capital cost of an SMR built in 2035 would be $12,681 per kW in 2022 year dollars. I used this as my low-cost trajectory. The high-cost trajectory is based on the assumption that the capital cost of an SMR built that year would be double the cost in the ATB, or just above $25,000 per kW, again in 2022 year dollars.

Q. Is it reasonable to expect that building an SMR will be as expensive as you assume in your high-cost trajectory?

A. Definitely. As I noted earlier, the costs of the first generation of reactors built in the United States tripled between the start of construction and when they began commercial operations. Also, the costs of the Vogtle Project increased by 157% after the start of construction and the estimated costs of its sister project at Summer skyrocketed before that project was cancelled in 2017. Finally, as I showed in Figure DS-4 above, the estimated cost of the NuScale SMR went up by 138% in just the three-plus years between 2020 and 2023, and the estimated cost of X-Energy's SMR grew by 72%, also in just a three-year period.

But even if construction costs don't grow as much as I suspect they will, as shown in Figure DS-10, the LCOE of the power from an SMR in nominal dollars will still be much more expensive than that from renewable and battery storage resources even with the large IRA ITC subsidies.

Figure DS-10.Comparative Costs of SMRs and Renewable Resources[57]



Q. What does the cost comparison in Figure DS-10 show?

A. This cost comparison shows that even with a 50% investment tax credit, the cost of power from an SMR will be far higher than the cost of power from wind, solar and solar + storage resources.

Q. What are your recommendations to the Commission regarding SMRs?

A. Based on the information in this section of my testimony, I recommend that the Commission prohibit PSCo from funding any steps to develop any SMR or large reactor project in Pueblo, or elsewhere in its service territory, using funds from its proposed Carbon Free Future Development mechanism. I further recommend that

[57] *Annual Technology Baseline, Nuclear*, NREL, https://atb.nrel.gov/electricity/2024/nuclear (last visited Apr. 17, 2025).

the Commission direct the Company to model a wide range of potential SMR capital costs and construction times given the significant potential for cost and schedule overruns on SMR or large reactor projects, Finally, I recommend that the Commission direct the Company to make public to its ratepayers any information it obtains about the estimated construction costs (both overnight and all-in), power costs and construction schedules of the SMR and large-reactor designs, and the CCS projects designs it is modeling or otherwise evaluating.

Finally, I recommend that the Commission direct the Company to make public as much of the information about the costs and schedules of proposed SMRs as possible.

VI. <u>Gas with CCS</u>

Q. Does PSCo propose to potentially provide funding for carbon capture and storage technologies through its Carbon Free Future Development proposal?

A. Yes, PSCo includes carbon capture and storage (CCS) in the list of "longer-timeline resources" that would be eligible for funding through the Carbon Free Future Development proposal.[58] The Company states that it "may consider developing a natural-gas-fired power plant with carbon capture project if a cost-effective project with suitable CO2 disposal can be developed in partnership with other entities."[59]

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[58] Hr'g Ex. 101, Ihle Direct 50:22–51:3.
[59] Hr'g Ex. 103, Tomljanovic Direct 37:11–13.

Q. In which scenario does the December 2023 PIESAC report talk about adding a 500 MW natural gas combined cycle gas-burning plant with CCS as a replacement for Comanche Unit 3?

A. It is discussed in Scenario 5 in the December 2023 PIESAC report.[60] In addition, the January 2024 PIESAC report recommends that PSCo consider building a new combined cycle gas plant with carbon capture in Pueblo.[61]

Q. Have you seen any evidence that carbon capture technology has been proven to be an effective and reliable tool for decarbonizing the CO_2 emissions from gas- or coal-burning power plants or industrial facilities?

A. No.

Q. What must CCS at a power plant or industrial facility do to be an effective tool for decarbonization?

A. CCS must capture all, or almost all, of the CO_2 produced by the power plant or industrial facility. And CCS must do so year-in and year-out over a period of decades, if carbon capture is to be relied upon as an effective and reliable tool for decarbonization.

Q. What claims do supporters of CCS make for how much CO_2 proposed CCS facilities will capture?

A. Over time, the claims of CCS supporters about the capture rates of proposed CCS facilities have climbed from 90% five or so years ago to >95% today. In fact, the

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[60] Hr'g Ex. 101, Attach. JWI-4 at 19.
[61] PIESAC, *Pueblo Innovative Energy Solutions Advisory Committee Report*, at 3.

December 2023 PIESAC report incredibly assumes that technology for 100% capture from a gas-fired power plant could be available after 2031.[62]

Q. Is there any actual evidence that any commercial-scale facilities with CCS will be able to reliably capture 100%, or even 90% or more, of the CO_2 they produce over the long term?

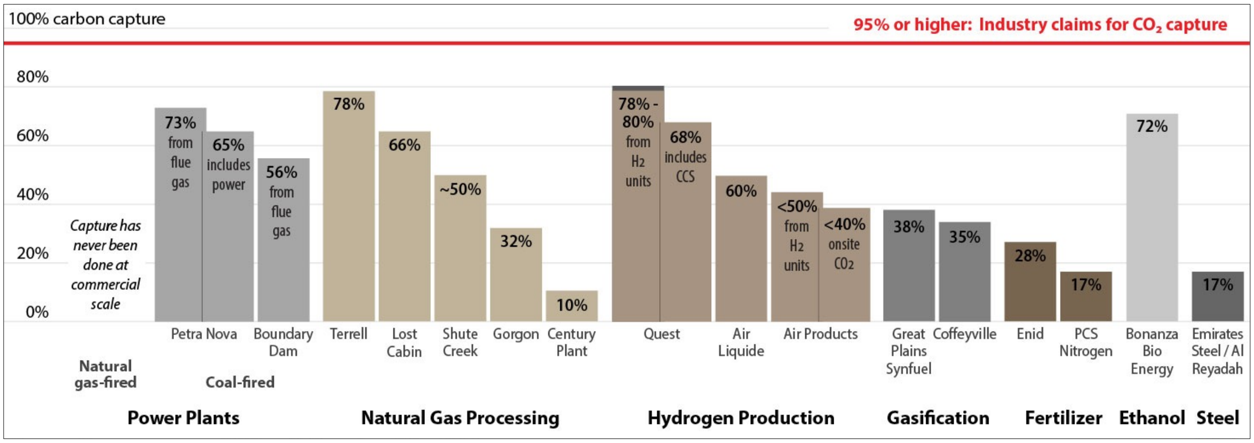
A. No. Contrary to what supporters of CCS suggest, there is no evidence that any existing CCS project has captured more than 80%, let alone 90% or more of the CO_2 it produces.

Q. What is the actual experience with capturing CO_2 at existing CCS projects?

A. Unfortunately, very few owners of existing carbon capture projects reveal either their actual CO_2 capture rates or release the underlying data that would enable anyone to determine their actual capture rates. Nevertheless, my former colleagues at the Institute for Energy Economics and Financial Analysis (IEEFA) and I have been able to calculate what we believe are reasonable estimates of the maximum potential CO_2 capture rates that have been achieved at about half of the CCS projects that were operating in world at the end of 2023. The following figure shows that none of the CCS projects for which we were able to find data achieved CO_2 capture rates anywhere close to the $\geq$95% that the industry and supporters claim for proposed projects.

[62] Hr'g Ex. 101, Attach. JWI-4 at 20–21.

Figure DS-11. There's No Evidence That Any CCS Project Has Achieved the Very High CO_2 Capture Rates Claimed for Future Projects[63]



Q. Have any CCS projects failed?

Yes. Carbon capture has had numerous failures and project cancellations—some very expensive.[64] So there's no guarantee that any proposed project will actually be successful at capturing 90% or more of its CO_2 over the long term.

Q. Is there general agreement on how much CCS will be needed to decarbonize the world's economies?

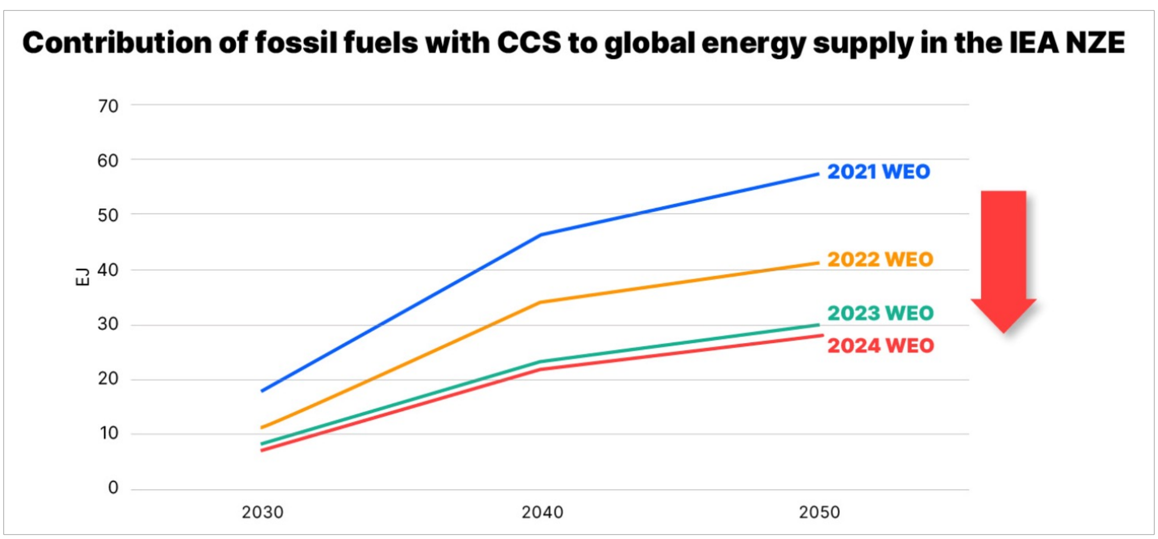
A. Not really. CCS supporters have claimed that some contribution from carbon capture will be essential for meeting the world's decarbonization goals. Even if

[63] Figure DS-11 reflects IEEFA analysis of publicly available data.
[64] U.S. Gov't Accountability Off., *Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects* (2021), https://www.gao.gov/products/gao-22-105111; *see also* Molly Taft, *The Energy Department Blew $1.1 Billion on Carbon Capture Projects That Were Mostly Failures*, Gizomodo, Jan. 11, 2022, https://gizmodo.com/the-energy-department-blew-1-1-billion-on-carbon-captu-1848338427; Nan Wang et al., *What went wrong? Learning from three decades of carbon capture, utilization and sequestration (CCUS) pilot and demonstration projects*, 158 Energy Pol'y (2021), https://www.sciencedirect.com/science/article/abs/pii/S030142152100416X.

that is true over the very long run, today's primary, most essential, and immediate need is to rapidly reduce, and hopefully eliminate our dependence on fossil fuels. For this reason, some recent analyses have reduced how much the world can and will rely on CCS in coming years.

For example, the International Energy Agency (IEA) is not anti-CCS by any means. However, as shown in Figure DS-12, IEA's last four annual World Energy Outlook New Zero Roadmaps show a sharply declining contribution of CCS to decarbonizing the global energy supply. As can be seen, IEA's view of how essential CCS is expected to be as a tool for decarbonization has changed dramatically in just three years, falling from nearly 60% in 2021 to slightly less than 30% in 2024.

Figure DS-12: The Estimated Contribution of Fossil Fuels with CCS to Global Decarbonization Is Declining[65]



[65] IEA, *Net Zero Roadmap, 2023 Update* (2023), https://www.iea.org/reports/net-zero-roadmap-a-global-pathway-to-keep-the-15-0c-goal-in-reach.

Q. Has any CO_2 been captured at a commercially sized gas-fired power plant?

A. The only instance where CO_2 was captured from a commercially operating gas-fired power plant was the capture of CO_2 from a slipstream of a mere 7% of the flue gases from a plant in Massachusetts. And this ended two decades ago. Other than this one example, I have not seen any evidence that any CO_2 has been captured from any commercial gas-fired power plant.

Q. What is a slipstream?

A. A slipstream means that a portion of the flue gases from a power plant is diverted to be processed through the carbon capture equipment. For example, in the case of the Massachusetts gas plant, the slipstream from which CO_2 was captured included only about 40 MW (or 7%) of the total flue gases from the 585 MW power plant. The project is said to have captured CO_2 from 1991 to 2005 but not since then.

Q. Has this limited experience of capturing CO_2 from a single gas-burning plant been generally accepted as proving or demonstrating that CCS will effectively and reliably capture CO_2 over the long term?

A. No. For example, the Edison Electric Institute (EEI) criticized the EPA's reliance on what it called "a dismantled project in Massachusetts" as supporting its finding that CCS is adequately demonstrated for new gas-based units.[66] The EEI also

[66] EEI Comments on EPA's Proposed Clean Air Section 111 Rules for Power Plants, Docket No. EPA-HQ-OAR-2023-0072, at 80 (Aug. 9, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0772.

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) slip stream project to capture CO_2 for use at an adjacent facility, and which was entirely dismantled 18 years before the current proposal as its principle example for demonstration within the industry. This is not sufficient to conclude that 90 percent capture at natural gas-based units is adequately demonstrated.[67]

Again, other than this single project, I have not seen any evidence that carbon capture has been attempted at any commercial-scale gas-fired power plant.

Q. Is it more difficult to capture the CO_2 from a gas-fired power plant than from other potential industrial uses or a coal-fired power plant?

A. Yes. As Company witness Tomljanovic testified:

> Carbon capture is a catch-all term describing the technology that is used to remove carbon dioxide ("CO2") from an industrial facility (e.g., power, chemicals, oil & gas, steel, cement) exhaust and/or directly from the air. The concentration of CO2 in the exhaust determines the cost, method, and technology that is used. Lower concentrations of CO2 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 CO2 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 CO2 can be one fourth that of coal plants which increases cost challenges.[68]

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[67] *Id.* at 80–81.
[68] Hr'g Ex. 103, Tomljanovic Direct 36:4–13.

I would add that the lower concentration of CO_2 in the flue gases from a gas-fired facility also would make it a more energy intensive to capture, and it is likely a more expensive process.

Q. If there is no actual recent experience with a gas plant capturing any of its CO_2, why does the government and CCS supporters assume that future carbon capture facilities will achieve CO_2 capture rates as high as 95% or even higher?

A. Without actual evidence from commercial-scale projects, the DOE and other supporters of CCS rely on claims made by the vendors of carbon capture technologies, potential developers of gas-burning plants, and/or the results of small-scale testing of new and evolving capture technologies—on the order of 1%–5% of the CO_2 emissions from commercial-scale projects. As I will discuss below, actual experience has shown that scaling up unproven technologies is a significant risk.

Q. How much CO_2 do these small-scale testing facilities capture?

A. The world's existing testing facilities capture relatively little CO_2 compared to what larger commercial-scale projects would need to capture year-in and year-out for decades, if they were going to be considered effective tools for decarbonization. For example:

- Testing at the U.S. National Carbon Capture Center is designed to capture only the daily equivalent of tens of tonnes of CO_2.[69]

[69] Press Release, BASF, BASF and Linde successfully complete pilot project at National Carbon Capture Center in Wilsonville, Alabama (July 19, 2016),

- The Technology Centre Mongstad in Norway has the capability of capturing roughly 300 tonnes of CO_2 a day (less than 200,000 tons per year) from an adjoining refinery and gas-fired power plant.[70]

- Two projects that are touted as "large pilot" carbon capture tests are designed to capture only ~150 tonnes per day (about 2.5%) of the CO_2 produced at the 405 MWe Dry Fork Station coal plant in Wyoming and only ~200 tonnes per day (roughly 5%) of the CO_2 produced by the Dallman 4 coal plant in Illinois.[71]

This is far less CO_2 than existing and proposed gas-fired combustion turbine and combined cycle facilities produce in a year. For example in 2023:

- The 1,588 megawatt (MW) natural gas-fired combined cycle (NGCC) Greensville County Power Station in Virginia emitted slightly less than 3.6 million metric tonnes of CO_2 in 2023.

- The 372 MW combustion turbine (CT) Montana Power Station in Texas emitted over 671,000 metric tonnes of CO_2 that same year.

Q. Does this mean that small- and pilot-scale testing is of little use?

A. Not at all. My point is not that small-scale testing of new technologies is wrong or without any benefit. Of course, it is an essential step in developing new

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https://www.basf.com/us/en/media/news-releases/2016/07/P-US-16-086; *see also* BASF & Linde, *Carbon capture, storage, and utilization*, https://assets.linde.com/-/media/global/corporate/corporate/documents/clean-energy/carbon-capture-storage-utilisation-linde-basf_tcm19-462558.pdf.

[70] Press Release, Mitsubishi Heavy Indus., Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New "KS-21™" Solvent for Carbon Capture (Oct. 19, 2021), https://www.mhi.com/news/211019.html.

[71] Mary Stroka, Integrated test center welcomes 2 carbon capture projects, County 17, May 3, 2023, https://county17.com/2023/05/03/integrated-test-center-welcomes-2-carbon-capture-projects/; Press Release, Nat'l Energy Tech. Lab., Large Pilot Carbon Capture Project Supported by NETL Breaks Ground in Illinois (Jan. 24, 2023), https://netl.doe.gov/node/12284; Press Release, Wyo. Governor's Off., Wyoming ITC to host large-scale carbon capture test project (Apr. 30, 2021), https://wyomingitc.org/wyoming-itc-to-host-large-scale-carbon-capture-test-project/.

technologies. What is wrong is CCS supporters' use of the results of small-scale tests as conclusive evidence that proposed power plants and industrial facilities with new or enhanced carbon capture technologies will definitely capture almost all of the CO_2 they produce when used at commercial scale and will reliably do so for decades.

Q. Has scaling up from small-scale testing to commercial-scale operations been a challenge for some new technologies?

A. Yes. As the industry and the DOE should have learned by now through painful experience, serious and expensive problems can occur when scaling up new technologies. Southern Company's Kemper Integrated Gasification Combined Cycle (IGCC) project is a prime example of where a new technology can look ready for commercial development when tested at small scale, but it fails to operate reliability when applied at commercial scale.

As initially proposed, Kemper was going to use a brand-new technology called TRIG™ for gasifying coal, with the ultimate goal of capturing 65% of the CO_2 before the gasified coal was burned at the plant.[72] According to Southern Company, TRIG™ had been successfully tested at the National Carbon Capture Center. However, when the TRIG™ technology was installed at the commercial-scale Kemper plant, significant and unsolvable problems were revealed that prevented the coal gasification process from operating reliably. As a result, the

[72] S. Co., *2017 Carbon Disclosure Report* 10 (2017), https://www.southerncompany.com/content/dam/southerncompany/images/news/2017_Carbon%20Disclosure%20Report.pdf.

plan to burn gasified coal was scrapped and Kemper (since renamed Plant Ratcliffe) now is most likely 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 produces has been captured.

This painful and expensive experience explains Southern Company's warning that new capture technologies need to be demonstrated at commercial-scale before being considered proven at 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.[73]

This warning should be heeded before utilities and the federal government commit to developing and/or funding proposed CCS projects at existing or new gas-fired power plants.

Q. Are you saying that there is no chance a CCS project will capture 90% or more of the CO_2 produced by a gas-burning NGCC?

A. No. It is possible that one of the capture technologies now being proposed for new gas-fired plants may indeed capture more than 90% or 95% of the CO_2 they

[73] S. Co. Comments on EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-Fired Power Plants, Docket No. EPA-HQ-OAR-2022-0723, at 7 (Dec. 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0723-0029.

would otherwise emit. But this success cannot be taken for granted based solely on the results of small-scale testing results.

Q. Are you alone in concluding that carbon capture has not proven reliable enough at commercial scale to show that capture rates of 90% of higher can consistently be achieved at gas-burning combustion turbines (SGCT) and NGCCs?

A. No. A large number of utilities and industry trade organizations, in addition to Southern Company, have submitted comments to the U.S. EPA on the proposed Greenhouse Gas Regulations for Fossil-Fuel-Fired Power Plants that have emphasized that CO_2 capture has not been proven reliable as a decarbonization technology at commercial-scale gas-burning turbines.

American Electric Power (AEP) has been cited as the first utility to deploy CO_2 capture on a working power plant, based on the installation of a CCS demonstration project on a portion of the company's coal-fired Mountaineer Plant in 2009. AEP, based on its own experiences with CCS, has concluded that carbon capture cannot be considered as the Best System for Emission Reduction (BSER) for existing or new gas-burning turbines. In comments submitted to the EPA in May 2024, AEP stated that "CCS is a promising technology but must overcome significant development challenges before it can be demonstrated to be BSER."[74] AEP further noted the following:

[74] AEP Comments on EPA's Non-Rulemaking Docket on Reducing Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Stationary Combustion Turbines, Docket No.

- As evident by AEP's first-hand experience with the CCS validation project at Mountaineer Plant, and as reinforced by other public and private efforts, 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 BSER.

- 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.[75]

Similarly, in its comments to the EPA on the proposed Greenhouse Gas Regulations for Fossil-Fuel-fired Power Plants, the Tennessee Valley Authority (TVA) concluded that there is insufficient evidence that CCS technology is currently feasible or reliable:

> CCUS is not yet adequately demonstrated and should not be considered [the Best System of Emission Reduction]. While some small-scale progress is being made through a variety of pilot projects, this technology has, unfortunately, not yet been developed enough to cross through into being "adequately demonstrated," as required for any BSER under the [Clean Air Act]. TVA has concerns that there is insufficient experience with CCUS at a commercial scale to find that the technology is currently feasible or reliable for widespread application. And, even if the technology were ready for more widespread deployment, several technological and legal issues remain to be resolved, including

EPA-HQ-OAR-2024-0135, at 4 (May 28, 2024), https://www.regulations.gov/comment/EPA-HQ-OAR-2024-0135-0110.

[75] *Id.* at 4–5 (emphasis added).

> geographical constraints, access to water, permitting for storage facilities, parasitic load, and cost.[76]

Q. Even if a project were able to capture 90% or more of the CO_2 from a gas-fired plant, would that mean it was reducing the total life cycle CO_2-equivalent (CO_2e) greenhouse gas emissions related to the plant by that same percentage?

A. No. Vendors of carbon capture technologies and developers of proposed CCS projects claim that a NGCC with CCS can capture all, or nearly all, of the CO_2 it produces. Even if that is possible, there would still be significant CO_2e associated with (1) upstream methane emissions between the 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 the captured CO_2, especially if it used for enhanced oil recovery. Thus, the project's effective life cycle CO_2e capture rate would be substantially lower than that for plant alone.

Q. Have you estimated what the effective life cycle capture rate for a gas plant would be if you included these related emissions?

A. Yes. I have analyzed what would be the effective life cycle CO_2e capture rate if upstream methane emissions and the downstream use of some of the CO_2

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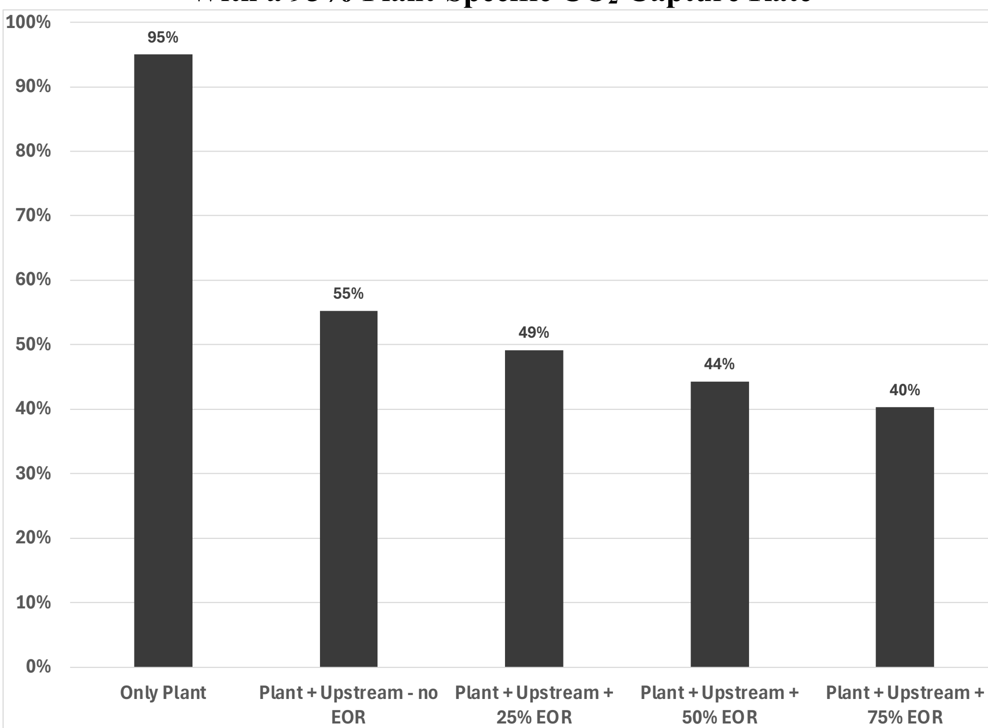
[76] TVA Comments on EPA's Non-Rulemaking Docket on Reducing Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Stationary Combustion Turbines, Docket No. EPA-HQ-OAR-2024-0135, at 5 (May 28, 2024), https://www.regulations.gov/comment/EPA-HQ-OAR-2024-0135-0069 (emphasis added).

captured from the NGCC used for enhanced oil recovery (EOR) were included. The results of this analysis are shown in Figure DS-13.

Figure DS-13. Effective Life Cycle CO_2e Capture Rates for a NGCC With a 95% Plant-Specific CO_2 Capture Rate



Thus, even if you accept that an NGCC with CCS could capture 95% of the CO_2 it produces, which I do not believe has been proven, its effective life cycle capture rate would be significantly lower if upstream methane and downstream CO_2 emissions are included. Consequently, the overall CO_2e associated with the NGCC would be substantially greater than if you focused only on the plant's capture rate.

Q. Why have you looked at five different scenarios in Figure DS-13?

A. There are five different scenarios in Figure DS-13 because it is unknown how much, if any, of the CO_2 captured at a new NGCC with CCS would be sold by

PSCo for use in EOR. However, to be clear, the evidence to date does not show that it is reasonable to assume that a CCS project at an NGCC in Pueblo or anywhere else would capture anywhere near 95% of the CO_2 it produces and do it year-in and year-out over a period of decades. And that is what CCS must do if it is going to be an effective tool for decarbonization.

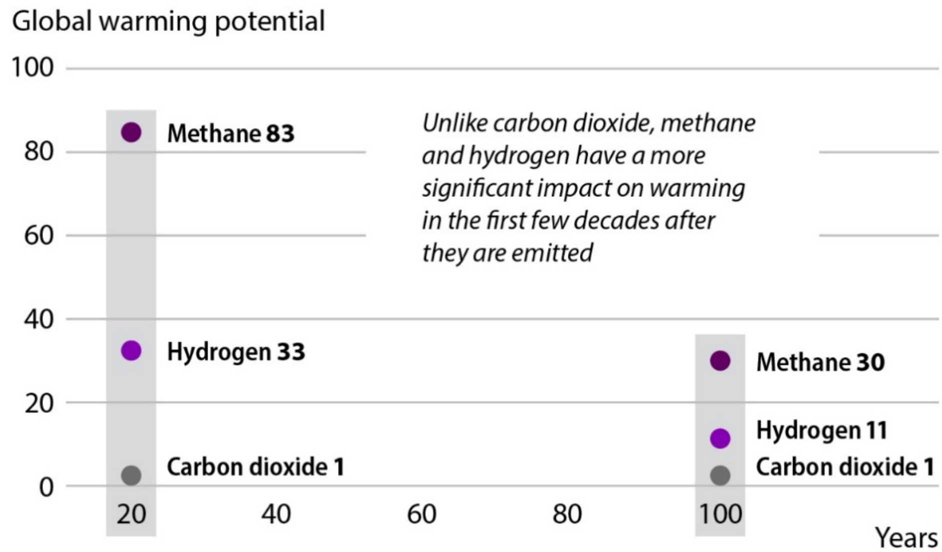
Q. Would Figure DS-13 look the same if you assumed that the capture rate at an NGCC with CCS was lower than 95%?

A. Yes. The effective capture rates shown in Figure DS-13 all would be lower depending on how low the NGCC plant's capture rate is assumed to be.

Q. What global warming potential (GWP) did you use for methane in this analysis?

A. Methane is a very potent greenhouse gas. The timeline used for its assumed GWP is important because the GWP for methane, and hydrogen as well, decline over time, as shown in Figure DS-14

Figure DS-14. Methane and Hydrogen 20-Year and 100-Year Global Warming Potential



Governments and the Intergovernmental Panel on Climate Change (IPCC) do generally use 100-year GWPs for greenhouse gases in their analyses. While the use of 100-year GWPs may have made sense decades ago to focus on how climate change was going to be a problem that would affect the world over the long term and, therefore, that 100-year GWPs of greenhouse gases were the most relevant. But that no longer holds true. The climate crisis that many have feared is already here and has already had widespread and rapid adverse impacts on the world and its climate, as the extreme heat and weather experienced on all seven continents this summer have confirmed. The most recent IPCC report observed:

> Widespread and rapid changes in the atmosphere, ocean, cryosphere and biosphere have occurred. Human-caused climate change is already affecting many weather and climate extremes in every region across the globe. This has led to widespread adverse impacts and related losses and damages to nature and people.

> Vulnerable communities who have historically contributed the least to current climate change are disproportionately affected.[77]

For this reason, many climate scientists now emphasize that "a focus on the next few years is exceptionally important,"[78] and that it's "now or never, if we want to limit global warming to 1.5 [degrees centigrade or] 2.7 [degrees Fahrenheit]."[79] Focusing solely on 100-year GWPs, as the DOE and other CCS supporters do, is misguided and minimizes the effects of critical shorter-lived gases like methane and hydrogen.

Clearly, one of the very best practices for avoiding taking actions that might make climate change worse in the short term, as well as the long term, is to consider 20-year GWP timeframes when determining how clean existing and proposed fossil-fired projects really are and whether to provide incentives for their construction and operation.

Q. How would the effective capture rates shown in Figure DS-13 change if you used methane's lower 100-year GWP, instead of its 20-year GWP?

A. Figure DS-15, below, shows that the effective capture rates with upstream emissions are higher than they were in Figure DS-13, if methane's lower 100-year

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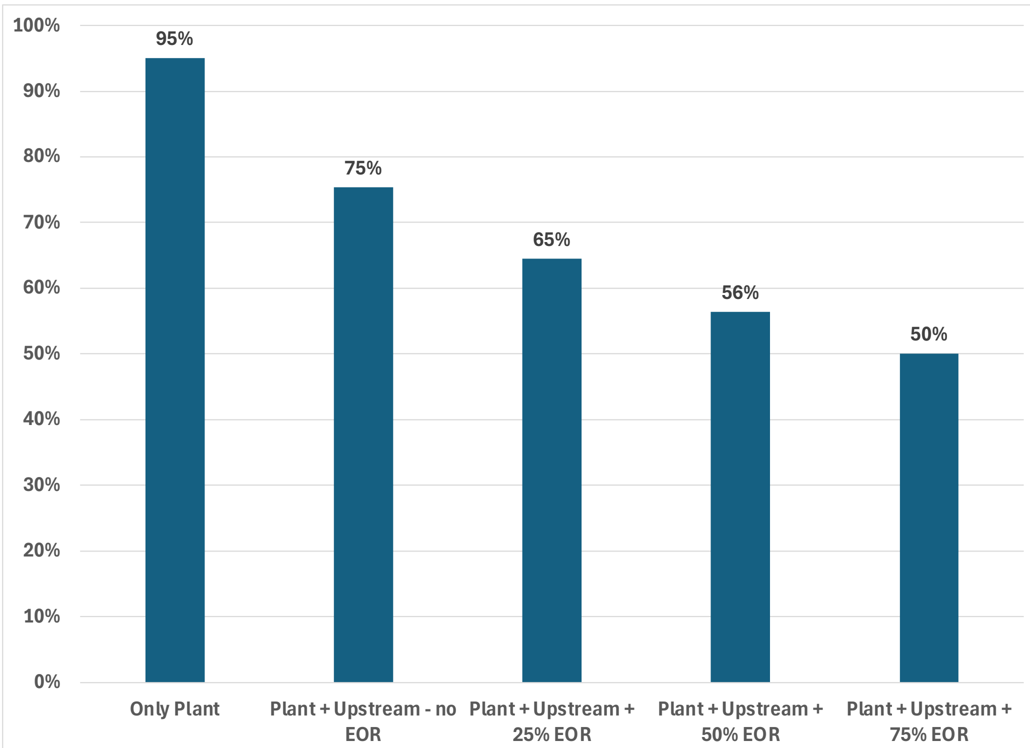
77 IPCC, *Climate Change 2023: Synthesis Report, Summary for Policymakers* 5 (2023), https://www.ipcc.ch/report/ar6/syr/.

78 Robert O'Neill, Harvard Kennedy Sch., *Harvard researchers provide policymakers a clearer picture on methane emissions* (Feb. 6, 2023), https://www.hks.harvard.edu/faculty-research/policy-topics/environment-energy/harvard-researchers-methane-emissions.

79 Press Release, IPCC, The evidence is clear: the time for action is now. We can halve emissions by 2030 (Apr. 4, 2022), https://www.ipcc.ch/site/assets/uploads/2022/04/IPCC_AR6_WGIII_PressRelease_English.pdf.

GWP is used. However, these life cycle CO_2e capture rates are still significantly lower than the 95% capture rate assumed for the gas plant.

Figure DS-15. Effective Life Cycle CO_2e Capture Rates with Methane's 100-Year GWP



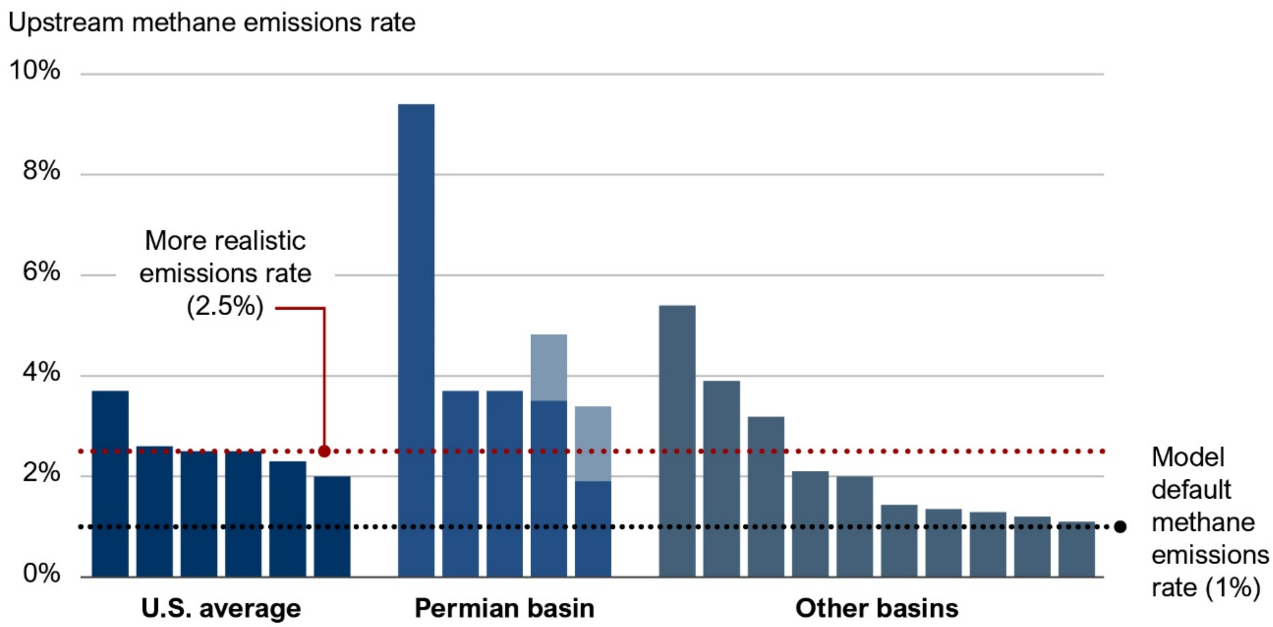
Q. What upstream methane emission rate did you assume in this analysis?

A. I assumed that 2.5% of the natural gas (which is on the order of 85% methane) would be emitted between the well and the gas plant.

Q. Why did you use this 2.5% upstream methane emission rate?

A. As part of the research for a 2023 report by the Institute for Energy Economics and Financial Analysis on which I was lead author, my former IEEFA colleague, Anika Juhn, and I reviewed the results of the recent scientific analyses and surveys of methane emissions that were available at that time.[80] The results of our review are shown in Figure DS-16 and Table DS-1, below.

Figure DS-16. Recent Scientific Analyses and Surveys of Methane Emissions[81]



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[80] David Schlissel & Anika Juhn, Inst. for Energy Econs. & Fin. Analysis, *Blue Hydrogen: Not Clean, Not Low Carbon, Not a Solution* (2023), https://ieefa.org/resources/blue-hydrogen-not-clean-not-low-carbon-not-solution.

[81] *Id.* at 13.

Table DS-1. Upstream Methane Emission Rate Studies[82]

Study	Year Published	Region	Leak Rate
Alvarez et al.	2018	U.S.	2.3%
Peischl et al.	2018	Bakken Shale, ND	5.4%
		Barnett Shale, TX	1.5%
		Denver Basin, CO	2.1%
		Eastern Eagle Ford Shale, TX	3.2%
		Western Eagle Ford Shale, TX	2.0%
Ren et al.	2019	Marcellus Shale	1.1%
Schneising et al.	2020	Permian Basin	3.7%
		Bakken Shale, ND	1.3%
		Eagle Ford Basin, TX	1.4%
		Anadarko Basin, OK	3.9%
		Appalachia	1.2%
Zhang et al.	2020	Permian Basin	3.7%
Lyon, et al.	2020	Permian Basin	1.9%-3.3%
		U.S.	2.5%
Chen et al.	2022	Permian Basin	9.4%
Shen et al.	2022	U.S.	2.0%
		Permian Basin	3.5%-4.6%
Howarth	2022	U.S.	2.6%
Lu et al.	2023	U.S. (in 2010)	3.7%
		U.S. (in 2019)	2.5%

Other recent aerial surveys have also found significantly higher methane emissions in major basins of natural gas production in the United States than had previously been included in the EPA's Greenhouse Gas Inventory.

- Methane emissions from natural gas gathering lines in the Permian Basin are at least 14 times higher than EPA estimates.[83] Gathering lines transport unprocessed gas from well sites to storage and processing facilities.

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[82] *Id.* at 14.
[83] Jevan Yu et al., *Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin*, 9 Env't Sci. & Tech. Letters 969 (2022), https://pubs.acs.org/doi/full/10.1021/acs.estlett.2c00380.

- Measurements from the Permian Basin, and the Bakken and Eagle Ford basins indicate that flaring is significantly less effective at reducing methane emissions—flaring is only 91.1% effective, vs. the previously estimated 98% efficiency.[84]

- The carbon intensity of oil and gas production in the Gulf of Mexico is double previous estimates. This is driven by updated methane emissions that are three and 13 times what had been previously estimated in federal and state water inventories, respectively.[85]

Robert W. Howarth, a Professor of Ecology and research scientist at Cornell University and an expert on methane emissions, has analyzed the results of all peer-reviewed estimates of methane emissions in gas fields in the United States prepared through the middle of 2022. Based on this analysis, which omitted the two highest satellite-based estimates as possible outliers, Howarth found that the median upstream methane emission rate is 3.7% of gas production. The mean emission rate, weighted by the volume of production in the different gas fields studied, is 2.6%.[86] Howarth's results are consistent with the results of the recent scientific surveys and analyses shown in Table DS-1 above.

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[84] Genevieve Plant, *Inefficient and unlit natural gas flares both emit large quantities of methane*, 377 Science 15,666 (2022), https://www.science.org/doi/10.1126/science.abq0385.

[85] Alan Gorchov Negron et al., *Excess methane emissions from shallow water platforms elevate the carbon intensity of US Gulf of Mexico oil and gas production*, 120 Proc. of the Nat'l Acad. of Scis. (2023), https://www.pnas.org/doi/10.1073/pnas.2215275120.

[86] Robert Howarth, *Methane Emissions from the Production and Use of Natural Gas*, Mag. For Env't Managers (2022), https://www.research.howarthlab.org/documents/Howarth2022_EM_Magazine_methane.pdf.

Q. How much additional oil is produced when CO_2 is injected into the ground for enhanced oil recovery?

A. Between two and four barrels of new oil can be produced by injecting a tonne of CO_2 into the ground, depending on the conditions in the field where it is used. For the purposes of the analysis shown in Figure DS-13, I have conservatively assumed that only 2.08 barrels of new oil are produced this way from injecting a tonne of CO_2 for EOR.[87] This figure came from DOE data.

Q. What did you assume for how much CO_2 is produced from burning a barrel of oil?

A. Based on EPA figures, I have assumed that burning each additional barrel of oil through EOR would produce, on average, 0.43 tonnes of CO.[88] Combining these two assumptions, the analysis shown in Figure DS-13 assumes that each tonne of captured CO_2 used for EOR produces 0.89 tonnes of additional CO_2 emissions when the oil is burned. That is the result of multiplying 2.08 x 0.43.

Q. Has PSCo committed to not selling any of the CO_2 that might be captured from a new NGCC for use in EOR?

A. No. In discovery, the Company stated that it might potentially sell some of the CO_2 captured at a natural gas-fired plant with carbon capture for use in EOR.[89]

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[87] *See* Thomas Overton, *Is EOR a Dead End for Carbon Capture and Storage?*, Power Mag., April 12, 2016, https://www.powermag.com/is-eor-a-dead-end-for-carbon-capture/.

[88] *Greenhouse Gas Equivalencies Calculator—Calculations and References*, EPA, https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator-calculations-and-references (last visited Apr. 17, 2025).

[89] PSCo Resp. to EJC 1-4(b) (Attach. DS-2 at 3).

Q. Have you assumed that after being injected into the ground, any of the tonnes of captured CO_2 leaks into the atmosphere?

A. No. I have conservatively assumed that none of the CO_2 injected into the ground for EOR would leak into the atmosphere.

Q. Are there any other potential sources of CO_2 leakage that you have not included in this analysis?

A. Yes. I have assumed that none of the captured CO_2 would be emitted downstream of the gas plant as it is piped and injected to be stored underground, or for use in EOR or any other use.

Q. Nevertheless, are there serious concerns with leakage during transmission, injection, and underground storage of captured CO_2?

A. Definitely. Two examples used by proponents of CCS to show how well underground storage works are the Sleipner and Snohvit projects off Norway. However, it has become clear that the CO_2 stored underground at Sleipner has migrated in ways that were not previously anticipated, and that Snohvit has considerably less storage capacity than had been claimed. As my former colleague from IEEFA has noted, even those scientists and engineers working on storage projects agree that CO_2 behavior will remain unknown until it is put into the ground, regardless of prior survey, engineering, or lab work that goes into site design and preparation. And once the CO_2 goes into the ground, it can only be monitored, not controlled.[90]

There are also safety concerns about leaks from CO_2 pipelines, including the health concerns raised after a CO_2 pipe ruptured in Satartia Mississippi in 2020.[91] The experience in Satartia plus those at Sleipner and Snohvit raise serious doubts about the safety of transporting and the effectiveness of piping and permanently storing CO_2 captured from fossil sources underground.

Q. Moving on, what are the most significant financial risks associated with using CCS to capture CO_2 from an NGCC?

A. The most significant financial uncertainties for CCS from an NGCC are:

1. The NGCC's annual capacity factor
2. The CO_2 capture rate
3. The CO_2 capture cost
4. The impact of the CCS equipment on the cost of the power produced by the NGCC
5. Natural gas prices

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[90] *See, e.g.*, Grant Hauber, Inst. for Energy Econs. & Fin. Analysis, *The carbon dioxide disposal chain: Elements, goals and risks* (2024), https://ieefa.org/sites/default/files/2024-09/2024Conf%20The%20carbon%20dioxide%20disposal%20chain.pdf; Grant Hauber, Inst. for Energy Econs. & Fin. Analysis, *Norway's Sleipner and Snohvit CCS: Industry models or cautionary tales?* (2023), https://ieefa.org/resources/norways-sleipner-and-snohvit-ccs-industry-models-or-cautionary-tales.

[91] Julia Simon, *The U.S. is expanding CO2 pipelines. One poisoned town wants you to know its story*, NPR, Sept. 25, 2023, https://www.npr.org/2023/05/21/1172679786/carbon-capture-carbon-dioxide-pipeline.

Q. Why is the NGCC's annual capacity factor important?

A. Simply, the tonnes of CO_2 captured by a NGCC + CCS plant depends on both how much is produced by the NGCC and how much is captured by the CCS. And that determines how many 45Q credits the owner of the plant will receive which, in turn, affects its profitability.

Q. Would this give the owner of a new NGCC an incentive to run the plant as much as possible?

A. Yes. The NGCC owner would have two ways to increase the number of 45Q credits it could receive for capturing CO_2—increase the CO_2 capture rate and/or increase the total amount of CO_2 it produces. Achieving as high a capacity factor as it possibly can is the way an owner can do the latter.

Q. Does this mean a new NGCC could compete with renewable resources instead of complementing them?

A. Yes.

Q. What is the approximate service life of a new NGCC?

A. Foty years I would think, if not longer.

Q. So a Commission decision allowing PSCo to replace Comanche 3 with an NGCC with CCS could have a long-term negative impact on Colorado's CO_2e emissions?

A. Yes.

Q. How would adding a CCS project to an existing or proposed gas plant affect the cost of the power from the plant?

A. Adding a CCS project increases the cost of power from a proposed NGCC in several ways. First, there's 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 would both be higher. For example, a 2023 DOE study shows that a gas plant's heat rate would rise by about 12% and its auxiliary loads would grow by about 35–45 MW.[92] This would mean the plant would burn more gas and, because its net power output would be reduced, it would have less electricity to sell. The combination of these impacts would adversely affect the cost of the power from a plant and its financial viability, even if it were collecting 45Q subsidies equal to its cost of capturing CO_2 on a tonne per dollar basis.

Q. Why would an NGCC's auxiliary loads go up if it has CCS?

A. Some of the gross power output of the NGCC would be consumed running the carbon capture equipment. Therefore, its net output would be lower.

Q. What has been the actual cost of capturing CO_2 from an NGCC?

A. There is no publicly available <u>actual</u> CO_2 capture cost for any plant burning gas. The cost of the very small capture project at the gas plant in Massachusetts has

[92] Tommy Schmitt et al., Nat'l Energy Tech. Lab., *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (2022), https://netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9.

never been published, and no other commercial-scale gas plant has captured any CO_2 at all.

Q. What about estimated CO_2 capture costs?

A. About five to ten years ago, the DOE and supporters of CCS claimed that CO_2 capture costs would decline by about 50%, to approximately $30 per tonne.[93] However, exactly the opposite has happened. Estimated CCS costs have gone up dramatically.

Q. What evidence suggests that estimated CCS costs have gone up substantially over the last five years?

A. There are three separate pieces of information that suggest the cost of capturing CO_2 will be substantially higher than was projected as recently as five years ago. This information includes (1) the dramatic increases in 45Q CCS tax subsidies sought by supporters of CCS and granted by Congress, (2) the results of DOE-funded studies, and (3) recent estimates from CCS supporters.

Q. How have the federal government's 45Q CCS tax subsidies increased in recent years?

Figure DS-17 shows how the federal government's 45Q CCS tax subsidies increased between 2008 and the passage of the Inflation Reduction Act in 2022.

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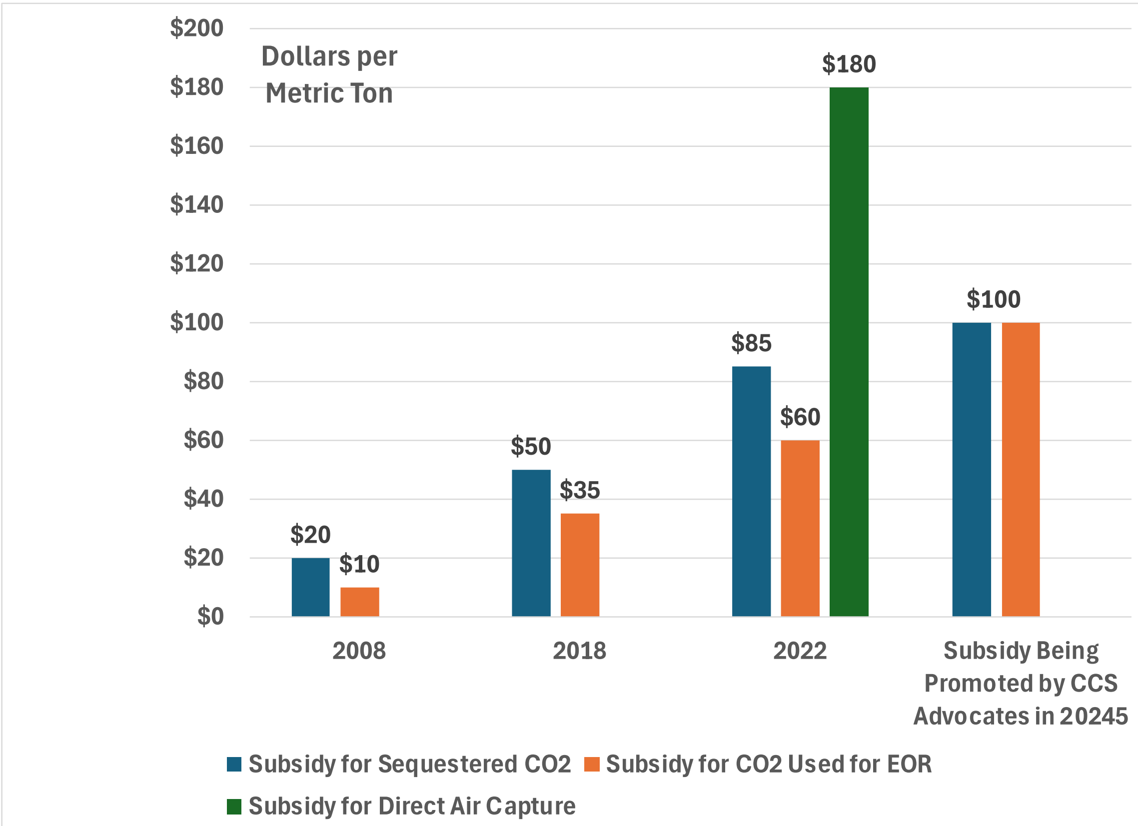
[93] Suzanne Mattei & David Schlissel, *The ill-fated Petra Nova CCS project: NRG Energy throws in the towel*, Inst. for Energy Econs. & Fin. Analysis, Oct. 5 2022, https://ieefa.org/resources/ill-fated-petra-nova-ccs-project-nrg-energy-throws-towel.

Figure DS-17. CCS 45Q Subsidies Have Gone Up, Not Down



For example, in response to pressure from supporters of carbon capture, the 45Q CCS tax subsidy has been increased to $85/tonne for geologically stored CO_2 and to $65/tonne for CO_2 used for EOR or other purposes. But supporters of CCS now claim these increases are not nearly enough to make CCS financially viable.

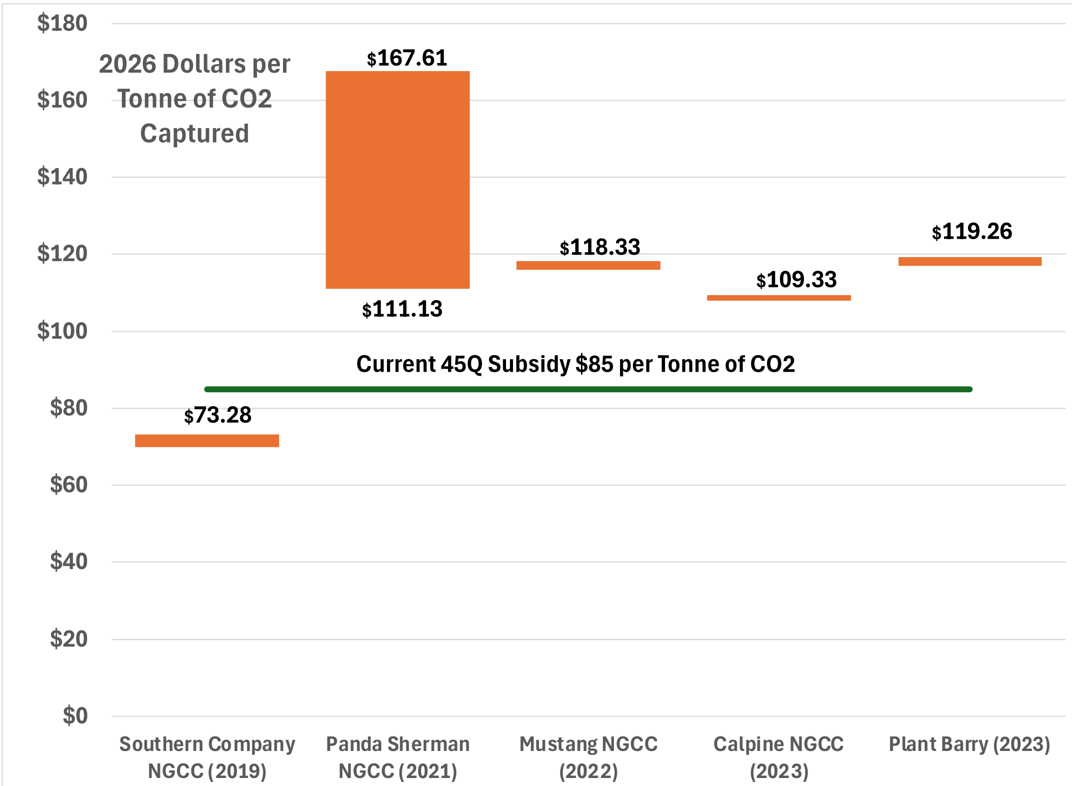
In fact, a coalition led by Exxon is already lobbying for an "initial" increase in the 45Q tax subsidy to $100/tonne for geologically stored CO_2 and an increase in the period during which projects could receive 45Q subsidies from the current 12 years to 30 years. They also want the subsidy for use of captured CO_2 for EOR to be the same as that for CO_2 stored underground.

Q. What DOE-funded studies have estimated the costs of capturing CO_2 at gas-fired facilities?

A. The DOE has funded a number of what are called "Front-End Engineering Design," or FEED, studies for preliminary engineering work on adding CCS to existing power plants and industrial facilities.[94] Figure DS-18 presents the results from each of the five FEED studies that specifically looked at adding CCS to gas-fired generators. The only change I made to the data was to escalate the capture costs in each of these FEED studies from the dollars in the year in which it was prepared to 2026 year dollars. I did this to be consistent with the current U.S. 45Q subsidy, which will be $85 per tonne in 2026.

[94] *See Carbon Capture Demonstration Projects Program Front-End Engineering Design (FEED) Studies Selections for Award Negotiations*, DOE, https://www.energy.gov/oced/carbon-capture-demonstration-projects-program-front-end-engineering-design-feed-studies (last visited Apr. 17, 2025).

Figure DS-18. FEED Studies Suggest Cost of Capturing CO2 at Gas-Fired Power Plants Will Be Higher Than The Current $85 45Q Subsidy



You can see that no one is suggesting that CO_2 capture costs will be anywhere near as low as $30 per tonne. In fact, none of the four most recent FEED studies suggest that the average cost of capturing CO_2 from an NGCC will be below $109 per tonne of CO_2 captured.

Q. What recent study by CCS supporters also suggests it will be very expensive to capture the CO_2 from NGCCs?

A. A February 2023 study by Energy Futures Initiative (EFI) estimated the CO_2 capture costs for a number of power and industrial sectors.[95] I escalated EFI's estimated cost for capturing CO_2 from the 2022-year dollars that were included in the study to 2026-year dollars. Doing this, I found that EFI was projecting that capture costs would fall within a low of $116 per tonne and a high of $148 per tonne. The actual costs paid to capture CO_2 from gas-fired plants will almost certainly be higher, perhaps much higher, than this because no new no new or retrofitted NGCC is likely to be in service by 2026. But the result of the EFI study is further evidence of the widening recognition that CO_2 capture costs are going up, not down.

Q. Why do you believe that estimated CO_2 capture costs have increased so dramatically in recent years?

A. Estimated CCS capture costs are going up, in large part, due to the very same factors that have led to increases in estimated SMR costs that I discussed previously. In particular, CCS capture costs have increased due to competition for the 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.

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[95] EFI, *Turning CCS projects in heavy industry & power into blue chip financial investments* (2023), https://efifoundation.org/reports/turning-ccs-projects-in-heavy-industry-into-blue-chip-financial-investments/.

Q. What evidence have you seen that the estimated construction costs of CCS projects are increasing?

A. There's not a lot of public data on the estimated, or for that matter, the actual costs of building carbon capture facilities, mainly because vendors have been successful in shielding their estimated costs from the public. However, there is evidence regarding the estimated construction costs of several proposed projects and one that has been built, which show that CCS is indeed going to be far more expensive than previously claimed by supporters.

For example, the estimated cost of Project Tundra, which proposes to convert the existing Milton R. Young coal plant to capture CO_2, nearly doubled in just three years—from ~$1 billion in 2020 to just under $1.94 billion in 2023.[96] To be fair, part of the increase in estimated cost appears to have been due to design changes, but a doubling in the project's estimated cost before construction has been started should, and does, cause concern.

Q. Have existing carbon capture projects been built on time and on budget?

A. There is not a lot of public data on actual costs and schedules of building CCS projects construction costs and schedules. However, I have seen statements that the Petra Nova project, which captures the CO_2 from a 240 MW slipstream of the flue gases from the W. A. Parish Unit 8 coal plant in Texas, was built on schedule

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[96] Joe Smyth, *Department of Energy analysis says coal carbon capture project would emit more greenhouse gases than it stores*, Energy & Pol'y Inst., Sept. 14, 2023, https://energyandpolicy.org/department-of-energy-analysis-says-coal-carbon-capture-project-would-emit-more-greenhouse-gases-than-it-stores/.

and at the budgeted cost of $1 billion. And I've seen no evidence that leads me to doubt that information.

However, it appears that the retrofitting of the 110 MW Boundary Dam 3 coal plant in Saskatchewan, Canada was more expensive that had been planned and that the project came online a year late.

The Kemper carbon capture project in Mississippi was scheduled to be completed in 2014, at a projected cost of about $3 billion. However, the project's cost ultimately skyrocketed to over $7 billion and it was completed several years late.[97] Southern Company claimed Kemper would capture 65% of the CO_2 it produced. But as I noted above, due to problems with the project's new coal gasification system, Kemper has not captured any CO_2 and, in fact, the portion of the plant devoted to carbon capture was demolished in October 2021. Instead of a success, Kemper has an extremely expensive plant that burns natural gas.

Q. Is it reasonable to expect that capture costs will go down in the future as developers actually start to build new CCS projects?

A. No. CCS supporters, like SMR supporters, claim that because of "learning by doing," capture costs will go down. But, as I discussed previously with regard to nuclear costs, assuming costs definitely will go down over time is a big gamble without any evidence to support it.

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[97] David Schlissel & Dennis Wamsted, Inst. for Energy Econs. & Fin. Analysis, *Holy Grail of Carbon Capture Continues to Elude Coal Industry* 8–10 (2018), https://ieefa.org/wp-content/uploads/2018/11/Holy-Grail-of-Carbon-Capture-Continues-to-Elude-Coal-Industry_November-2018.pdf.

Q. When developers claim that their proposed gas-fired project is or will be "carbon capture ready," does that mean they already have technology in place to capture CO_2 from the project?

A. No. The term "carbon capture ready" stirs images that all that will be needed to capture CO_2 at a proposed project will be to press a button or turn a switch. But this is misleading. Generally, the phrase merely means that there will be space at the project site to add the necessary CO_2 capture technology when it is available and the developers have decided it will be economic to add it.

Q. How would lower capture rates affect the per tonne estimated cost of capturing CO_2 at a power plant or industrial facility?

A. The FEED studies for NGCC plants generally assume that the CCS project will capture somewhere in the range of 85% to 95% of the CO_2 it produces. However, as can be seen in Figure DS-19, below, the average cost of capturing CO_2 will go up as if a project's actual capture rate is lower than the value assumed in the FEED study.

Figure DS-19. Average CO_2 Capture Costs Increase When Capture Rates Go Down and/or When CCS Capital Costs Go Up

Q. Why are there four lines in Figure DS-19?

A. In addition to showing how the average cost of capturing CO_2 at a gas-fired plant goes up as its capture rate goes down, Figure DS-19 shows how estimated average per tonne of capture change with assumed increases or decreases in capital and O&M costs.

Q. What are the sources of the costs shown in Figure DS-19?

A. The capital and O&M costs used to derive the Low, Base and High lines come directly from the FEED study for the Panda Sherman NGCC in Texas.[98] The high and low lines reflect a ±15% change in capital cost and an approximate ±34% change from the O&M cost assumed in the FEED study. These were cost increase/decreases assumed in the FEED study. I added a fourth case, Very High Capital, which assumes a 50% increase from the capital cost in the Base case but retains the ~34% O&M cost increase in the High case.

Q. Have the costs of NGCCs changed in recent years?

A. Yes. Combustion turbine prices have risen substantially in recent years and lead-times have lengthened significantly due to increased competition and the decision by vendors not to expand their manufacturing facilities to satisfy the increasing demand for turbines out of fear that the demand could disappear and their investment lost.[99] For example, NextEra's CEO, John Ketchum said during the company's recent webinar on its Q4 2024 earnings that the cost to build a new combined cycle gas-fired plant has tripled since the company built its last unit, the 1,260 MW Dania Beach facility that came online in 2022.[100]

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[98] Bill Elliott, *Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant* (2022), https://www.osti.gov/biblio/1836563.
[99] *See, e.g.*. Advait Arun, *The Natural Gas Turbine Crisis*, Heatmap, Feb. 26, 2025, https://heatmap.news/ideas/natural-gas-turbine-crisis.
[100] *NextEra Energy (NEE) Q4 2024 Earnings Call Transcript*, Motley Fool, https://www.fool.com/earnings/call-transcripts/2025/01/24/nextera-energy-nee-q4-2024-earnings-call-transcrip/ (last visited Apr. 17, 2025).

Q. Have any CCS projects been cancelled in the last year?

A. Yes. Last May, Capital Power Corporation cancelled a proposed CAN$2.4 billion carbon capture and storage project at an existing NGCC in Alberta, Canada. The company said that while the project might be technically viable, it no longer made financial sense.[101] Another six or seven gas projects that were seeking low interest funding from the state of Texas have recently withdrawn from the fund.

Q. How much does PIESAC assume it would cost to build an NGCC with carbon capture?

A. The PIESAC assumes that building an NGCC with CCS would cost $1.345 billion. But like the rest of PIESAC's estimated construction costs, this does not include owners' costs.

Q. Is this a reasonable cost for a new NGCC with CCS?

A. No. It might be enough to acquire the turbines and the other equipment needed for an NGCC. However, I would expect that the cost of the equipment and components for CCS would easily bring the total cost to more than $2 billion.

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[101] Wallis Snowdon, *Plans for $2.4B carbon capture and storage project near Edmonton have been cancelled*, CBC News, May 2, 2024, https://www.cbc.ca/news/canada/edmonton/plans-for-2-4b-carbon-capture-and-storage-project-near-edmonton-have-been-cancelled-1.7191573.

Q. What is your conclusion regarding adding an NGCC with CCS as the replacement for Comanche 3?

A. Like SMRs and new large reactor designs, CCS is burdened by unproven technology, uncertain performance, unknown costs and schedule, and the lack of a track record as an effective and reliable tool for decarbonization.

Q. What are your recommendations for the Commission on the gas + CCS alternative proposed by the PIESAC committee?

A. I recommend that the Commission prohibit PSCo from funding any steps to develop any gas + CCS project through the Carbon Free Future Development mechanism. I also recommend that the Commission, based on what is unknown about the costs and effectiveness of CCS, direct the company to model wide ranges of carbon capture rates, CCS construction costs, and gas turbine prices; and to model the full life cycle CO2e emissions of each gas + CCS scenario its models or otherwise evaluates. Finally, I recommend the Commission direct the Company to make public to its ratepayers any information it obtains about the estimated CO_2 capture performance and the estimated construction costs (both overnight and all-in) and schedules of the CCS project designs it is modeling or otherwise evaluating.

In addition, I recommend that the Commission direct the Company to make public as much of the information about the costs and schedules of proposed CCS projects as possible.

VII. SCGT-Burning Hydrogen

Q. Did the December 2023 PIESAC report study scenarios that involve building a gas plant that burns hydrogen?

A. Yes, two of the scenarios in the December 2023 PIESAC report analyzed burning hydrogen at a gas plant. One scenario involved building a 250 MW simple cycle gas turbine that uses hydrogen fuel and a medium duration energy storage solution, and another scenario involved a 500 MW stand-alone simple-cycle gas turbine with hydrogen fuel.[102]

Q. Would burning hydrogen in a gas turbine be an effective tool for decarbonization?

A. The two most commonly projected ways to make hydrogen are (1) what's commonly called "green hydrogen," which is produced by using electricity from renewable resources to power electrolyzers in which water molecules are broken into their constituents hydrogen and oxygen; and (2) by producing what is called "blue hydrogen" from the methane in natural gas. There are a number of other ways to produce hydrogen using either the electricity from an SMR to power the electrolyzers or making it from biogas. However, I believe these both have significant issues that make them financially and/or technically infeasible. Therefore, I'm not discussing them in this testimony, although much of what I say applies to them as well.

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[102] Hr'g Ex. 101, Attach JWI-4 at 18–19.

To be fair, hydrogen does have the benefit that when burned, it does not produce any CO_2. And green hydrogen is, of course, made using electricity generated by renewable resources. These factors are behind what some have called the "hopium" (a combination of hope and opium meaning unfounded hope) behind claims that hydrogen will be a key tool for decarbonization that have run wild the past few years.[103]

Q. Let's look at green and blue hydrogen one at a time. First, is burning green hydrogen in gas turbines currently an effective tool for decarbonization or will it be one in the foreseeable future?

A. No. The world has a number of essential uses for hydrogen, and using green hydrogen in these applications could be a tool for decarbonization. However, making green hydrogen and then burning the hydrogen in a turbine is not one of these. Instead, it is a very inefficient and wasteful process. After all, why use the renewable electricity to produce hydrogen in the first place when it can be better used to displace fossil fuels directly?

Q. What is the basis for this conclusion?

A. I calculated the efficiency of burning green hydrogen in very efficient SCGT and NGCC units using the following steps:

[103] Credit is due to Michael Liebreich and Paul Martin for applying this term to hydrogen. *See Chemical Engineer Paul Martin Reflects on Liebreich's Hydrogen Ladder & #Hopium—Part 1*, Clean Technica, https://cleantechnica.com/2021/09/01/cleantech-talk-chemical-engineer-paul-martin-reflects-on-liebreichs-hydrogen-ladder-hopium-part-1/ (last visited Apr. 17, 2025). I would note that it also applies as well to the SMR and gas + CCS options I've previously discussed.

- I started with how many cubic feet of natural gas are burned in a very efficient (that is, low heat rate) NGCC and a SCGT. For this analysis, I chose the Greensville NGCC, which had an average 6500 btu/kwh in 2024 and the Montana Power Station SCGT (which is in Texas, not Montana), which had an average 9200 btu/heat rate the same year. These were among the most efficient NGCC and SCGT units at burning natural gas during the year.
- Using the H2Tools site developed by the DOE's Pacific Northwest National Laboratory to convert the mmcf of natural gas consumed by each plant in 2024 to the kilograms of hydrogen that would be needed to generate the same MWhs of electricity as each unit actually produced.[104]
- Based on a literature search, I assumed that 50 KWh of electricity from renewable resources would be consumed to produce one kilogram of green hydrogen in an electrolyzer.
- Finally, I divided the figure by the unit's actual generation in 2024.

Q. What were your results?

A. On average, producing enough green hydrogen to generate each MWh of electricity from burning green hydrogen in an efficient SCGT turbine would consume 3.86 MWh of electricity from renewable resources—for a round-trip efficiency of just 26%. Producing enough green hydrogen to generate electricity in an efficient NGCC would be a bit more efficient, requiring 2.68 MWh of

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[104] Hydrogen Tools, https://h2tools.org/sites/default/files/2017-12/energy_equivalency_calculator.html (last visited Apr. 17, 2025).

electricity from renewable resources for each MWh of electricity generated by the power plant—a round trip efficiency of 37%.

Q. Have you included any efficiency loss from transmission and/or storage of the hydrogen?

A. No. These results assume that the green hydrogen production facility would be immediately next to the power plant and that the green hydrogen would be burned immediately after it was produced. Assuming any additional loss in efficiency from transmission and/or storage would make the round-trip efficiency of the processes even worse in both SCGT and NGCC.

The bottom line is that producing green hydrogen and then burning it as a fuel in power plants is a waste. Green hydrogen should be used only where absolutely essential and where there is no feasible alternative.

Q. Would burning hydrogen produced from methane, commonly called blue hydrogen, as a fuel in an SCGT or NGCC be an effective decarbonization tool?

A. No. The production, transportation, and combustion of clean (i.e., very low-carbon) hydrogen all involve technical uncertainties and risks that likely will take years to resolve and will be extremely expensive, if, indeed, they are ever resolved. It's not as simple as connecting a new turbine to a natural gas pipeline in Pueblo and having clean blue hydrogen or a blend of clean blue hydrogen and natural gas flow into a turbine for combustion.

Q. Please explain.

A. Burning blue hydrogen in a turbine as a decarbonization tool is really the last step in a longer process. First, you need a source of methane in natural gas. Second, you need to transport that methane from the well to the blue hydrogen production facility. Third, you need a pipeline network to transport that blue hydrogen from the production facility to the turbine. And finally, you need a turbine with materials and design features that are compatible with burning hydrogen or a blend of hydrogen and natural gas containing a high percentage of hydrogen by volume. But even then, producing, transporting and burning blue hydrogen might not reduce CO_2e emissions by that much, if at all.

Q. What is clean hydrogen?

A. The 2022 Inflation Reduction Act defined qualified clean hydrogen as that which emits 4.0 kilograms or less of CO_2e for each kilogram of hydrogen produced. This is called having a carbon intensity (CI) of 4.0 or less.

Q. Are there any production facilities in the United States that currently produce hydrogen that meet this standard?

A. No.

Q. Is there a set schedule when clean hydrogen that meets this standard will be available?

A. No.

Q. Is it even certain that PSCo would be able to obtain any clean hydrogen that meets this standard if and when it becomes available?

A. No. As I will discuss, I don't believe that the hydrogen that will be produced in the plants currently being proposed/planned around the United States will actually meet the federal government's clean hydrogen standard. But even if it does, it's uncertain when any clean hydrogen that meets the standard will be available, and how great the demand will be. Thus, it is completely unknown if PSCo will be able to obtain any clean hydrogen for burning in a new SCGT in Pueblo.

Q. How is the carbon intensity of blue hydrogen calculated?

A. The carbon intensity of blue hydrogen is determined from running the DOE's GREET (Greenhouse Gases Regulated Emissions Energy Use in Technologies) model.

Q. Is there a certain set of assumptions that must be input into the GREET to produce the final result that the blue hydrogen being produced in a facility has a carbon intensity of less than or equal to 4.0 kilograms of CO_2e emitted per kilogram of hydrogen produced?

Yes. A finding that blue hydrogen is clean under the federal government's standard follows from the following four key assumptions:

- That only 0.9 percent of the methane is, and in the future will be, emitted into the atmosphere upstream of the facility where the hydrogen is produced, even though recent scientific surveys and analyses have found much higher emission rates in major U.S. oil and gas-producing basins.[105]

- That methane's lower 100-year GWP, and not its very potent 20-year GWP, needs to be included in the analysis of how clean and low-carbon blue hydrogen actually is.
- That blue hydrogen production facilities definitely will capture 94.5% or more of the CO_2 they produce depending on the technology they use to produce blue hydrogen—even though there is no evidence that any commercial-scale carbon capture facility in the world has done so.
- That the 20-year and 100-year global warming effects of hydrogen downstream of the production facility should be ignored entirely.

Q. Are these reasonable assumptions?

A. I was lead author for a report titled "Blue Hydrogen: Not clean, not low carbon, not a solution."[106] After looking at the latest scientific evidence about the emission rates of methane and hydrogen and the performance to date of capturing CO_2 at hydrogen production facilities, we determined that these DOE key assumptions were not realistic and not based on the best and most recent science available.

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[105] Upstream methane emissions include the losses at the well sites, plus those incurred during the processing, storage, and transport of gas in high-pressure pipelines.

[106] David Schlissel & Anika Juhn, Inst. for Energy Econs. & Fin. Analysis, *Blue Hydrogen: Not Clean, Not Low Carbon, Not a Solution* (2023), https://ieefa.org/resources/blue-hydrogen-not-clean-not-low-carbon-not-solution.

Q. Have you already discussed the first two of these assumptions—the appropriate upstream methane rate to use and the need to use methane's 20-year GWP, not solely its 100-year GWP?

A. Yes. See the discussion proceeding and following Figure DS-16 and Table DS-1 above.

Q. Turning to the question of capturing CO_2 from hydrogen production facilities, how much of the hydrogen produced in the world today relies on fossil fuels without any carbon capture?

A. I've seen it quoted that 99% of the dedicated hydrogen production in the world today relies on fossil fuels without any carbon capture.[107] Based on my experience, I think that's an acceptable figure.

Q. Do hydrogen production facilities without carbon capture emit a lot of carbon dioxide?

A. Yes. The production of hydrogen without carbon capture is very dirty, meaning the carbon intensity of the hydrogen produced this way is on the order of ≥10-20 kilograms of CO_2e per kilogram of hydrogen produced.

[107] Paul Martin et al., *A review of challenges with using the natural gas system for hydrogen*, 12 Energy Sci. & Eng'g 3995 (2024), https://scijournals.onlinelibrary.wiley.com/doi/10.1002/ese3.1861.

Q. What two processes are currently most used for producing hydrogen from methane?

A. Steam methane reforming is the most widely used process around the world to produce hydrogen from methane.[108] A different process, autothermal reforming (ATR) is expected to become more widely used in coming years.

Q. What capture rates does the DOE assume in the GREET model for hydrogen production facilities using each of these facilities?

A. The DOE assumes that a hydrogen production facility using steam methane reforming will capture 96.2% of the CO_2 it creates. It similarly assumes that a facility using ATR will capture 94.5%.

Q. Does the DOE perform any sensitivity analyses using lower CO_2 capture rates before deciding whether blue hydrogen is clean or not?

A. No. Users of the GREET model can change the assumed CO_2 capture rate, but I've not seen any evidence that the DOE performs any sensitivity analyses before deciding whether the blue hydrogen being produced at a facility has a carbon intensity of ≤ 4.0.

Q. How many facilities around the world using steam methane reforming to produce blue hydrogen have captured any of the CO_2 they create?

A. Only three.

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[108] Steam methane reforming is commonly referred to as SMR, but I've chosen to write the full name out to avoid confusing with small modular reactors.

Q. What capture rates have these facilities achieved?

A. None of these facilities has captured even 80% of the CO_2 they produce. Only one, Project Quest in Alberta, has captured 78% of its CO_2, and it only appears to have achieved that level of performance if the emissions associated with the capture process are ignored. If you include the CO_2 associated with the carbon capture process, Project Quest's capture rate is below 70%. DOE has estimated that the other two facilities capture just 60% of the CO_2 they create when producing hydrogen.

Q. How many facilities around the world using ATR to produce blue hydrogen have captured any of the CO_2 they create?

A. At the time we were preparing our 2023 report on blue hydrogen, there were zero facilities around the world using ATR to produce hydrogen that captured any of the CO_2 they created.

Q. Nevertheless, is there any reason to believe it may be possible that a facility using ATR might achieve a capture rate of higher than 60% in the future?

A. Yes. It is possible that new hydrogen production facilities using autothermal reforming will achieve higher CO_2 capture rates than those using steam methane reforming have achieved in the past. However, as we stated in our report, "it still remains a big gamble how close future capture rates will be to the near-perfect performance assumed in GREET."[109]

[109] Schlissel & Juhn, *Blue Hydrogen: Not Clean, Not Low Carbon, Not a Solution*, at 19.

Q. It is important to consider hydrogen's impact on global warming when determining whether blue hydrogen's carbon intensity and whether it is clean?

A. Yes. As we quoted in our September 2023 report on Blue Hydrogen:

> Hydrogen matters for the global climate because its emissions extend the life of methane in the atmosphere and increase its concentration. . . . Although hydrogen is not a greenhouse gas, changes in its abundance in the atmosphere will change the concentrations of important greenhouse gases. Scientists have warned that this process can have "decades long climate consequences."[110]

Q. Is hydrogen a much smaller molecule than methane?

A. Yes. Hydrogen is the lightest and the smallest molecule.

Q. Is this important?

A. Yes. As we noted in September 2023, "[d]ue to its extremely small size, hydrogen is a "slippery" module that can be expected to leak into the atmosphere at every stage of the hydrogen production value chain, from production to compression to pipeline transport through final use.[111] And, as a recent paper on challenges with using the natural gas system for hydrogen has noted, because hydrogen is a much smaller and lighter than methane, hydrogen has an "[o]verall tendency to leak at a greater extent through intact materials of construction, seals, and piping joints," it

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[110] *Id.* at 23.
[111] *Id.*

"[p]ermeates faster from gaskets, seals, plastic pipes and other 'soft' materials," and it "[r]equires much more energy to convert to a liquid state."[112]

Q. Is there a typical or average hydrogen leak rate?

A. No. Because there is currently no commercially available sensing technology that can detect the very small leaks through which hydrogen can escape into the atmosphere and affect the climate, it is unknown how much hydrogen is currently being emitted from existing production facilities and the downstream processes (compression, storage, and transport) in the hydrogen production value chain.[113] Consequently:

> Without any empirical data on actual leakage rates, scientific analyses of the climate impact of hydrogen emissions have frequently looked at a wide range in their studies, generally from 1% or less to about 10%. It is far better to recognize that the amount of hydrogen being emitted into the atmosphere is unknown than to pretend that such emissions do not exist at all . . . .[114]

Q, What did you assume for a hydrogen emission rate in your September 2023 study on blue hydrogen?

A. We assumed a 5% average hydrogen leakage rate—the approximate midpoint in the 1% to 10% range of leakage rates we found were assumed in scientific studies.

[112] Martin et al., *A review of challenges with using the natural gas system for hydrogen*, at 3997.
[113] Schlissel & Juhn, *Blue Hydrogen: Not Clean, Not Low Carbon, Not a Solution*, at 23–24.
[114] *Id.* at 24.

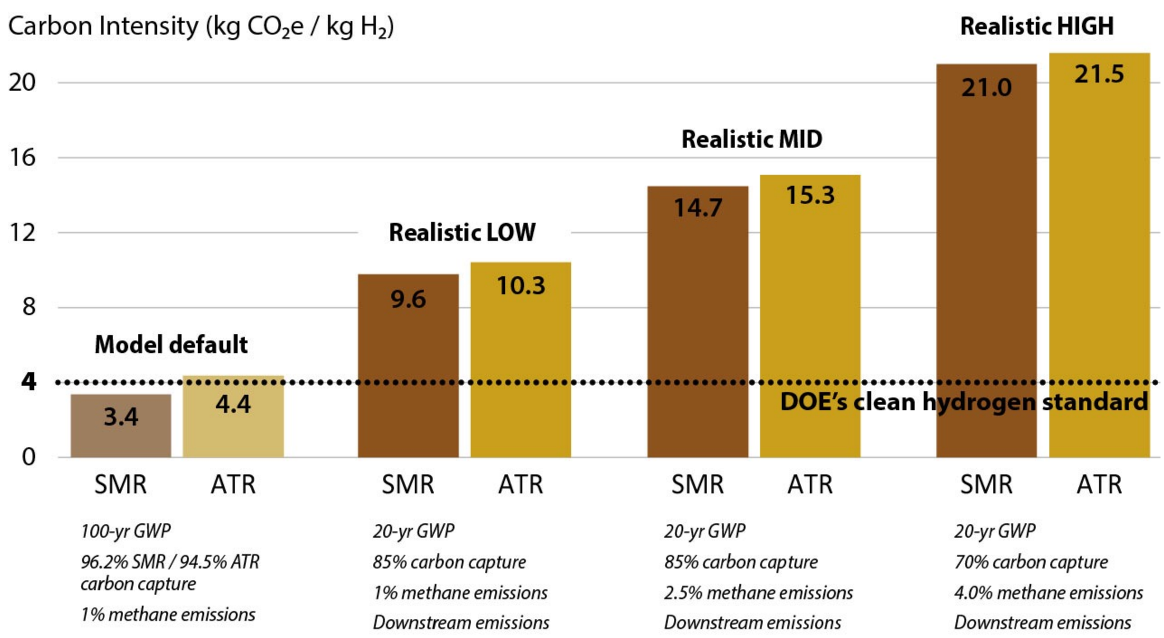
Q. Did you analyze what blue hydrogen's carbon intensity would be if you assumed more realistic real-world and science-based estimates for these four flawed DOE assumptions in its assessment of how clean blue hydrogen is?

A. Yes. We looked at a wide range of scenarios reflecting different upstream methane leakage rates, different CO_2 capture rates, both 20-year and 100-year GWPs, and with and without minor downstream hydrogen emissions.[115]

Q. Can you please give some examples of your results?

A. Yes. Please see Figure DS-20 below.

Figure DS-20. Examples of Blue Hydrogen Carbon Intensities Using Real-World and Science-Based Assumptions[116]



[115] *Id.* at 29.
[116] *Id.* at 27.

As you can see, blue hydrogen is an extremely dirty fuel when more real-world and science-based assumptions are used in the DOE's GREET model. This is true if the only changes you make are (1) to use methane's 20-year GWP, and (2) a slightly lower 85% CO_2 capture rate.

Q. Are there any other significant differences in physical and chemical properties between hydrogen and methane, that in addition to size, could limit blue hydrogen's effectiveness as a tool for decarbonization?

A. Yes. Hydrogen also has only about 1/3 the energy density per volume as methane, it reacts more strongly with other molecules, it has an 8 times faster flame speed, it has a flame that is less visible, and it burns at a higher temperature.[117] This means that compared to methane, hydrogen:

- "[a]ccelerates fatigue cracking and reduces fracture toughness of steels"
- "[m]ay be depleted in underground storage"
- has a "[h]igher fire risk"
- has "[l]ower flame stability in burners" and a "risk of flash-back;"
- when burning, is "[h]arder to detect"
- produces more NOx when burned[118]

[117] Martin et al., *A review of challenges with using the natural gas system for hydrogen*, at 3998.
[118] *Id.* at 3997.

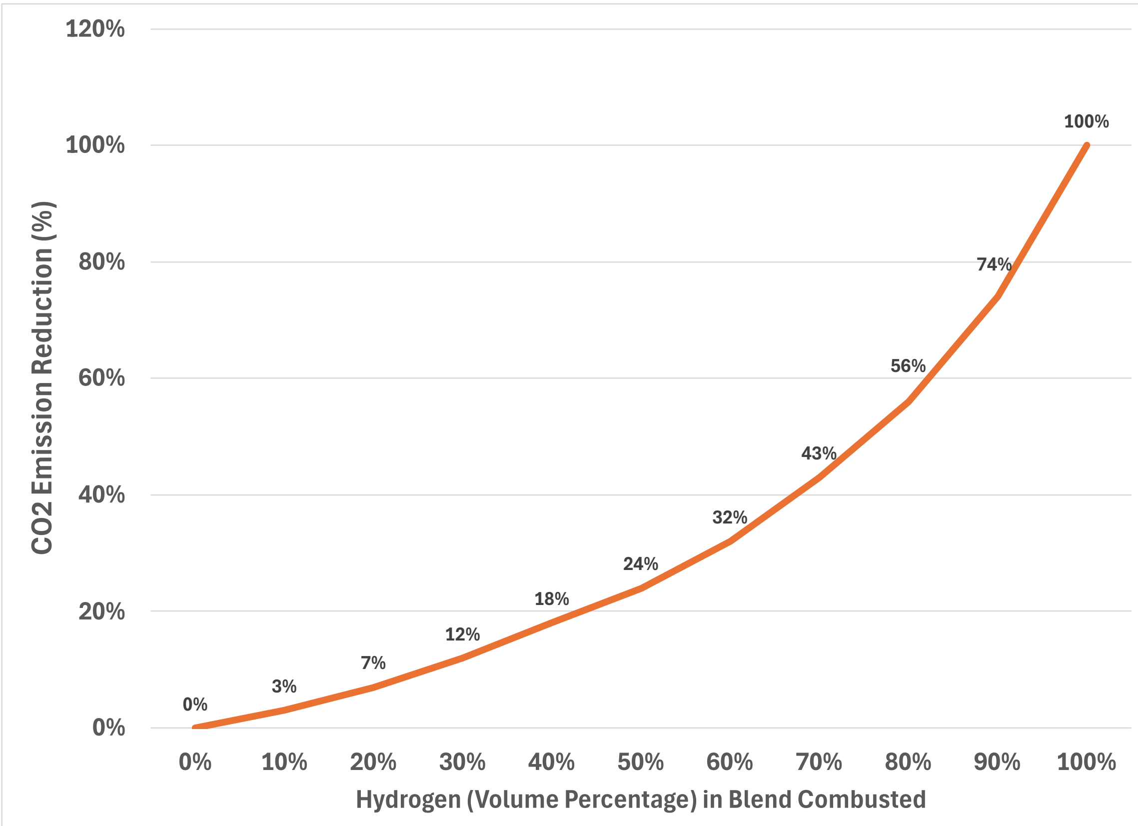
Q. What do these different physical and chemical properties mean for hydrogen's use as a fuel?

A. Because hydrogen's energy density, on a volume basis, is about one-third that of methane, three times as much hydrogen as methane is needed to provide the same amount of energy to generate an equal amount of electricity in a turbine. At the same time, the gas velocity required in a pipeline to deliver the same amount of heat energy per unit of time (such as in an hour) is three times as fast with hydrogen as with methane. In addition, hydrogen's much smaller size means it is much more likely to leak from piping into the atmosphere during transportation and diffuse into metals to cause pipe cracks, failures, or other problems with the materials used in the construction of pipelines and turbines.

Q. What is the significance of the fact that hydrogen only has one-third or less of the energy density by volume as methane?

A. This means that if you want to achieve significant reductions in CO_2 emissions, you either have to burn only 100% hydrogen or a blended gas of hydrogen and natural gas that is as close to 100% hydrogen as you can get.

Figure DS-21. CO_2 Emission Reductions Increase as the Percentage of Hydrogen in a Hydrogen-Natural Gas Blend Goes Up[119]



As you can see, if you burn a blend containing 20% hydrogen and 80% methane, the net reduction in CO_2 emissions is just 7%. Burning a 50% hydrogen blend reduces CO_2 emissions by only 24%. Burning even a blend that is 70% hydrogen would only reduce CO_2 emissions by 43%. It is only when the blend is above 90% or higher hydrogen that you start to achieve really significant reductions in CO_2. But transporting a gas blend with that high a percentage of hydrogen increases the

[119] GE, *Hydrogen for power generation* 6 (2002), https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf.

risk that the pipes carrying the hydrogen-gas blend could experience accelerated cracking and failures.

Q. Do the results of demonstration testing in existing turbines confirm that there is only a relatively small reduction in CO_2 emissions unless you burn a blend with a high percentage of hydrogen and a low percentage of natural gas?

A. Yes.

Q. How extensive is the existing natural gas pipeline network in the United States?

A. I've seen estimates that there are three million miles of natural gas pipelines in the country.

Q. Have many miles of dedicated hydrogen pipelines are there in the United States?

A. Approximately, 1500 miles, concentrated in Texas and Louisiana.

Q. What evidence have you seen that transporting hydrogen in the existing natural gas pipeline network could lead to pipe cracks, failures, or other problems as a result of the materials used in pipeline construction?

A. A number of recent reports and papers have raised concerns about the serious risks of transporting a blend of hydrogen and natural gas in existing natural gas pipelines. For example, a recent paper concluded that there is "considerable risk of premature failure if natural gas pipes are re-purposed for [hydrogen] service."[120] The paper further stated:

> There are several issues with using the current natural gas transmission system for H_2, relating to pipeline material, line capacity, valves, and compressors. Hydrogen accelerated fatigue cracking (HFAC) is the primary concern in converting existing natural gas pipelines for H_2. In high-yield strength steels commonly used in gas transmission pipelines, exposure to molecular hydrogen combined with cyclic stress, initiated at manufacturing or welding flaws or corrosion points in the piping system, increases the growth rate of cracks. The process, known as HAFC, occurs because hydrogen atoms diffuse into the steel. The cracks may ultimately extend through the wall of the pipe, causing it to leak or burst. The hydrogen atoms can also recombine into molecular hydrogen gas at defects in the steel. Low-yield-strength steel pipes are not particularly susceptible to fatigue cracking unless both temperature and the partial pressure are quite high.
>
> Recent, extensive testing of typical pipeline materials in Europe demonstrates both acceleration of fatigue cracking and reduction in fracture toughness when hydrogen is used, but the impacts vary widely depending on the material. Welds and their heat-affected zones, as well as manufacturing or fabrication defects in the pipe increase vulnerability by serving as crack initiation sites. The issue has been known for decades.
>
> Pipe failure is of concern due to potential asphyxiation and fire and explosion. Because natural gas pipes are usually buried, external inspections are difficult and internal inspections are largely relied upon to verify the integrity of the pipe material. Consequently, there is a considerable risk of premature pipe failure if natural gas pipes are re-purposed for H_2 service. . . .[121]

The same paper concluded:

> However, hydrogen has fundamentally different physical and chemical properties to natural gas, with major consequences for safety, energy supply, climate and cost. . . . We find that every

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[120] Martin et al., *A review of challenges with using the natural gas system for hydrogen*, at 4000.
[121] *Id.* (parentheticals and footnotes omitted).

> value chain component [of the piping system] is challenged by reuse. Hydrogen blending can circumvent many challenges but offers only a small reduction in greenhouse gas emissions due to hydrogen's low volumetric energy density. Furthermore, a transition to pure hydrogen is not possible without significant retrofits and replacements. Even if technical and economic barriers are overcome, serious safety and environmental risks remain.[122]

A technical report by NREL that reviewed the state of hydrogen blending technology identified a similar set of challenges associated with hydrogen blending in transmission and distribution gas piping networks. These included:

- Enhanced fatigue crack growth in pipeline steel
- Reduced fracture resistance in pipeline steel
- Reduced energy transmission capacity
- Increased pressure drop when meeting energy demand
- Increased gas velocities
- Increased required compressor power
- Increased NOx emissions for prime movers and end users
- Excessive combustion dynamics, flame lift-off, flashback
- Meter accuracy and durability
- Valve leakage and durability
- Gas composition analysis accuracy
- Hydrogen leakage in polymer piping (in distribution networks)
- Biochemical hydrogen corrosion in underground storage
- Hydrogen loss through the cap rock in underground storage[123]

The NREL report also found: "Gaseous hydrogen has a considerable effect on fatigue and fracture resistance of steels, including pipe steels and any other steel components operating at pressure within a pipeline. These effects are important because fatigue crack growth and fracture resistance are properties used directly

[122] *Id.* at 3995.
[123] Kevin Topolski et al., NREL, *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology* 10 (2022), https://www.nrel.gov/docs/fy23osti/81704.pdf.

in fitness-for-service assessments of pressure pipe . . . ."[124] The report further warned:

> Current research in line pipe steels and welds have focused on post-1990 material samples, whereas most of the U.S. natural gas pipeline system is composed of pre-1970s (or vintage) steel. This vintage steel line pipe may contain higher quantities of defects due to initial lower manufacturing quality and inherent wear from operation over service lifetime. The population and extent of defects will likely have a significant impact on pipe suitability for hydrogen blending and remaining service lifetimes, especially for environments containing hydrogen. . . . The material qualities of these vintage pipes and their response to hydrogen environments introduce considerable operational uncertainty and safety risks[125]

Q. What can be done to address these issues?

A. Potential measures could either be the use of new pipelines with materials compatible with hydrogen, or the hydrogen could be blended with natural gas below certain levels so that the hydrogen accelerated fracture risk is reduced. However, as a recent report noted:

> [T]his significantly limit[s] the decarbonization potential of using hydrogen, because it is not safe to pursue higher blending rates without undertaking retrofits or complete replacement of pipes. Even with small percentage admixtures of molecular hydrogen in high pressure natural gas pipes made of high-yield strength carbon steels it is expected that considerable acceleration of fatigue cracking, by as much as 30-fold, will occur with fracture resistance of the piping material reduced by as much as 50%.[126]

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[124] *Id.*
[125] *Id.* at 43 (parentheticals omitted).
[126] Martin et al., *A review of challenges with using the natural gas system for hydrogen*, at 4000.

Whatever solution is attempted, rather than simply ignoring the problem and hoping for the best, is likely to take a very long time and be very expensive.

Q. Would it be possible to bring hydrogen by truck to an SCGT in Pueblo?

A. That is possible, but it is not really viable or likely due to the huge amount of hydrogen that would be needed to run a 500 MW SCGT, as proposed by the PIESAC, even at a low 10% capacity factor and the limited carrying capacity of pressurized hydrogen carriers—and possibly the very long distances over which the hydrogen would have to be trucked. There are also other potential issues such as the possibility for hydrogen leakage during the trucking, as well as the wasted amounts of the energy that would have to be used to compress the hydrogen so it could be trucked.

Q. Are there turbine models with materials and design features that make them hydrogen compliant, available today?

A. Yes. Turbine vendors say that they already have hydrogen-compliant turbine designs. However, given the current problems and delays in the turbine supply chain, I don't know how expensive such a hydrogen-compliant turbine would be or how long it would take to get one for installation on PSCo's system.[127]

[127] *See, e.g.*. Advait Arun, *The Natural Gas Turbine Crisis*, Heatmap, Feb. 26, 2025, https://heatmap.news/ideas/natural-gas-turbine-crisis.

Q. Do utilities generally accept that burning blended gas with a high percentage of hydrogen in existing turbines is a proven or demonstrated technology?

A. Some have, but many haven't. For example, AEP noted the following in its May 2024 comments to the EPA:

> Current combustion turbine technology does not support the co-firing of hydrogen at the previously proposed rates of 20-30% blends, and certainly not at 90% + co-firing rates.
>
> Existing natural gas pipeline infrastructure is not capable of transporting 100% hydrogen or even high percentages of hydrogen. The fact that infrastructure does not exist for transporting even small amounts of hydrogen is further evidence that this option has not been adequately demonstrated.[128]

TVA's comments in the same EPA Docket similarly stated that "[h]ydrogen co-firing could become a promising technology for some applications but has not been adequately demonstrated for electric power generation."[129]

But this question is being tested at demonstration projects at a number of existing turbines around the country. Even if it is ultimately determined that burning 100% hydrogen, or gas blends with very high percentages of hydrogen, is demonstrated for existing turbines, the demonstration testing being conducted by

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[128] 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, at 5–6 (May 28, 2024), https://www.regulations.gov/comment/EPA-HQ-OAR-2024-0135-0110.

[129] TVA 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, at 5 (May 28, 2024), https://www.regulations.gov/comment/EPA-HQ-OAR-2024-0135-0069.

turbine owners and vendors likely is going to take a long time. And it is possible that the result may vary from turbine to turbine.

For example, when the 461 MW Long Ridge combined cycle plant in Ohio began commercial operations in 2021, it was lauded as a major step forward because it was "purpose-built to transition from natural gas to hydrogen blends and ultimately be capable of burning 100% hydrogen."[130] Yet later that year, the owner of the plant said that despite the successful completion of testing using a blend with 5% hydrogen, he expected that it might be a decade before further testing showed that the plant could burn 100% hydrogen.

Q. If PSCo decided that it wants to add an SCGT in Pueblo that burns a very high blend of hydrogen, how soon would that likely be possible?

A. That's a complicated question with a number of unknowns. First, is the question I addressed above: when will combustion turbines and other plant equipment that is compliant with hydrogen be available? But that may be the easier question to answer.

The more difficult questions are when, if ever, will there be a supply of clean, low carbon hydrogen available for the company to purchase? And when will there be a hydrogen-compliant pipeline infrastructure available to transport the hydrogen from where it is produced to Pueblo? There are no answers for either of these questions. The future of green hydrogen is, no pun intended, up in

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[130] Sonal Patel, *First Hydrogen Burn at Long Ridge HA-Class Gas Turbine Marks Triumph for GE*, Power Mag., Apr. 22, 2022, https://www.powermag.com/first-hydrogen-burn-at-long-ridge-ha-class-gas-turbine-marks-triumph-for-ge/.

the air given developments in the federal government, as is the plan to develop hubs around the nation producing what they claim will be clean, low-carbon blue hydrogen from methane.

Q. What is your overall conclusion on the PIESAC scenario in which PSCo would add an SCGT in Pueblo as a replacement for Comanche 3?

A. Considering the issues I have addressed in my testimony, I think it will be a very long time before there will be truly clean hydrogen available at a site in Pueblo for an SCGT to burn, if, indeed, it is ever possible. And until that happens burning hydrogen will not be a reliable tool for decarbonization.

I fear that if PSCo installs an SCGT or an NGCC in Pueblo, or anywhere else on its system, that it claims is "hydrogen-ready," it would burn 100% natural gas for an indefinite period in the future without any reductions in CO_2 emissions or even with increases in emissions.

Q. What are your recommendations to the Commission concerning the burning of green hydrogen made from renewable resources in turbines to produce electricity?

A. I recommend that the Commission find that burning green hydrogen made using the electricity from renewable resources in a turbine to produce electricity will be a wasteful process and not an effective tool for carbonization.

Q. Are you making the same recommendation concerning the burning of hydrogen produced using the electricity from an SMR or large reactor?

A. Yes.

Q. What is your recommendation to the Commission concerning the burning of blue hydrogen made from the methane in natural gas in a turbine to produce electricity.

A. Given the technical uncertainties and risks I have outlined in this testimony, I recommend that the Commission find that burning blue hydrogen made from the methane in natural gas in a turbine to produce electricity will not at any time in the foreseeable future be an effective and reliable tool for decarbonization.

VIII. Recommendations on the Carbon Free Future Development Proposal

Q. Do you have any recommendations for the Company's Carbon Free Future Development proposal?

A. Yes. I recommend the Commission modify PSCo's Carbon Free Future Development proposal in three ways.

Q. What is your first recommendation?

A. My first recommendation is that the Commission direct PSCo to study the potential development of a renewable energy park in Pueblo and to fund that study, and a related stakeholder process, out of the $100 million it is seeking for its Carbon Free Future Development proposal. Such a stakeholder process will allow a diverse set of stakeholders to discuss and make recommendations for how PSCo should implement a renewable energy park in Pueblo. The Commission should also instruct the Company to invite all the parties in this case, a diverse range of Pueblo community members, and Energy Innovation to participate in the stakeholder process.

In addition, the Commission should order PSCo to file a report in this proceeding no later than one year after the Commission's final Phase I decision that discusses and recommends the next steps for establishing an energy park in Pueblo. This report should also summarize the feedback and proposals the Company received from the participants in the stakeholder process. Parties should have thirty days to submit comments responding to PSCo's Pueblo renewable energy park report.

Q. Please briefly describe what you mean by a renewable energy park.

A. The December 2024 report by Energy Innovation titled "Energy Parks – A New Strategy to Meet Rising Electricity Demand" succinctly describes an energy park as follows:

> An energy park combines generation assets, complementary resources like storage, and connected customers (co-located loads). Energy parks can feed electricity and grid reliability services to the bulk power grid while maintaining a degree of self-sufficiency to provide crucial support for co-located loads. Essentially, an energy park is a large-scale microgrid.
>
> Energy parks with co-located loads are particularly compelling for large customers due to the cost advantages of sourcing electricity directly from the cheapest, cleanest sources and due to the challenges of connecting large capacities to the existing grid. Energy parks also provide new pathways to achieving the massive increases in clean electricity generation needed to achieve U.S. climate goals, including the target of halving economy-wide emissions by 2030.[131]

[131] Eric Gimon et al., Energy Innovation Pol'y & Tech. LLC, *Energy Parks: A New Strategy to Meet Rising Electricity Demand* 8 (2024), https://energyinnovation.org/report/energy-parks-a-new-strategy-to-meet-rising-electricity-demand/ (Attach. DS-3).

Energy Innovation's recent April 2025 report also summarizes what a renewable energy park in Pueblo would entail:

> An energy park as we envision here consists of four main components working in concert to support the electricity grid and its users. The four components are 1) renewable energy (primarily wind and solar), 2) short-duration battery storage, 3) flexible industrial customers that can use electricity when wind and solar generation are high but ramp down when available output is low, and 4) long-duration energy storage in the form of additional flexible technologies that can both store energy and reconvert it to electricity.
>
> For Pueblo, these components would be sited primarily in-county, using the existing Comanche coal plant substation as a primary hub for coordination and interconnection, but with projects spread across the city and county. With some incremental high-voltage line capacity, some of the wind resources could be sited out-of-county, in further southeast Colorado, but still work in concert with the other parts of the energy park.
>
> These resources can be constructed over time, building up the energy park into a grid resource that is even more reliable and flexible than the original coal plant and diversifying the sources of tax revenue and job base in Pueblo.[132]

[132] Eric Gimon & Michelle Solomon, Energy Innovation Pol'y & Tech. LLC, *Flexible, Clean Industry and Sustainable Energy Power Strong Economies: A case study in Pueblo, Colorado* 5 (2025), https://energyinnovation.org/report/flexible-clean-industry-and-sustainable-energy-power-strong-economies-a-case-study-in-pueblo-colorado/ (internal footnote omitted) (Attach. DS-4); *see also* Eric Gimon & Michelle Solomon, Energy Innovation Pol'y & Tech. LLC, *Renewable Energy Parks: An Economic Development Strategy for Pueblo, Colorado* (2025), https://energyinnovation.org/report/energy-parks-an-economic-development-strategy-for-pueblo-colorado/ (Attach DS-5).

Q. Has the Commission expressed an interest in energy parks in this proceeding?

A. Yes. Shortly after Energy Innovation issued its initial report on energy parks in December 2024, the Commission expressed an interest in energy parks in one of its interim decisions in this case. The Commission stated:

> We note the recently published report by Energy Innovation on co-locating new load and generation for the overall benefit of the system. We also note that the Company has proposed bonus incentives for new generation located within transition communities and has indicated that it will facilitate discussions with just transition communities to site large new loads in those communities. However, the Company may have failed to adequately evaluate the benefits when new generation and new load are located together as outlined in the Energy Innovation report. We flag this issue as an area of interest for the forthcoming Denver Metro CPCN proceeding and note that we will be requiring the Company to quantify the benefit of adding load outside of the Denver Metro constraint.[133]

Q. Does the EJC support developing a renewable energy park in Pueblo?

A. Yes. As Mr. Valdez explains in his Answer Testimony, the EJC supports building truly clean, renewable energy resources in Pueblo, and it opposes replacing the coal plant with nuclear, gas with CCS, or a hydrogen-burning turbine that would exacerbate the historical inequities Pueblo faces. The EJC believes that developing a renewable energy park in Pueblo holds great promise for advancing a truly just transition.

[133] Decision No. C24-0956-I at 17–18 ¶ 44 (Dec. 31, 2024) (internal footnote omitted).

Q. In your view, what would be the benefits of a renewable energy park in Pueblo?

As shown in the recent analyses by Energy Innovation, a renewable energy park could provide substantial benefits to PSCo, its ratepayers, the state of Colorado, and the local economy and taxpayers in and around Pueblo:

1. The energy park can deliver energy to the grid 99% time matched with a corrected version of the Comanche Unit 3 dispatch schedule.
2. The energy park can create the jobs and tax revenue needed to replace Comanche Unit 3—over 350 jobs and up to $40 million in annual tax revenue. Because the energy park would be made up of multiple different resources, it also would diversify Pueblo's economy and tax base.
3. The flexible loads included in the energy park are central to jobs, tax revenue, and reliability because they help keep energy in Pueblo, help balance additional renewable energy capacity, and provide energy back to the grid from thermal batteries. Thermal batteries as flexible loads would help PSCo and Colorado meet clean heat standard targets, and electrolyzers could take advantage of the additional Colorado green hydrogen tax credit.
4. The cost of the energy park to Colorado's electricity ratepayers could be less than half that of a small modular reactor ($3 billion vs. $5 to $10 billion or more).

5. Because PSCo could start building an energy park in the next few years, the just transition replacement tax revenues would be reduced and jobs and energy from Comanche could be replaced sooner.

Overall, Energy Innovation's Pueblo case study illustrates how flexible industrial loads running at a 25-70% load factor and dispatched by the utility can play a catalytic role for grid reliability and affordability in a renewables heavy mix, while providing significant local economic benefits. While the technology is available today, with significant industry interest, rate design and utility resource planning need to catch up to take advantage of this opportunity, not just in Pueblo but statewide where existing facilities using large boilers can be electrified and new industries can be incubated.

In addition, the renewable energy park would give the Company valuable flexibility in its resource planning. This would enable it to avoid being trapped in expensive nuclear and gas investments should the dramatic increases in future demands, such as those now being forecasted by PSCo for the loads from new data centers and AI, not materialize or materialize differently than expected. At the same time, new resources could be added in a relatively shorter number of years if demand grows at a higher rate than now expected. This flexibility is vital in today's dynamic energy transition.

Q. Is the EJC proposing that the Commission order PSCo to implement the specific renewable energy park that Energy Innovation analyzed for Pueblo?

A No, the April 2025 Energy Innovation report contains an illustrative case study of what could be included in a Pueblo renewable energy park. While this case study is a good starting point, the EJC recommends that the Commission order PSCo to begin studying and implementing a Pueblo renewable energy park, and the details of the renewable energy park would be determined through those processes and future Commission proceedings.

Q. Would an energy park with an SMR, a gas-fired turbine with CCS, or a hydrogen-burning turbine provide these same benefits as the renewable energy park that Energy Innovation analyzed?

A. No, for a number of reasons. First, the two turbine options would not produce any reduced CO_2 emissions in the next few years, if indeed, they ever do given their associated technology uncertainties. A new SMR likely wouldn't provide any CO_2 emission reductions within a decade or longer. This simply should not be acceptable given the climate emergency the world is facing.

Second, even with uncertain benefits, the SMR option is certain to be much more expensive for PSCo's ratepayers than a renewable energy park, as is the turbine + CCS option. The total cost of the hydrogen-burning turbine option is completely unknown at this time, and not even considered by the PIESAC.

Third, it is uncertain whether any of the three technologies will work as effectively as they have been advertised. The turbine + CCS option could turn out to be a turbine without CCS if the capture technology doesn't work well. Similarly, the success of the hydrogen-burning turbine option depends on the uncertain availability of truly clean hydrogen and the existence of a hydrogen-compatible network that can transport clean hydrogen to Pueblo.

Fourth, none of these resources would be as flexible as a renewable energy park, as each would require expensive long-lead time investments. In addition, starting down the road with any of these options would be a very big gamble that the future demands now being forecast will actually materialize.

Finally, there is no "first-mover" benefit to rushing ahead to be the first, or even among the first, to try to build and operate unproven technologies, particularly large, risky and expensive projects. A far smarter move is to watch what is happening to other projects trying to use the same technologies, and learn from their mistakes and successes. While a renewable energy park may be a relatively new concept, it would likely consist largely of established technologies that do not present the "first-mover" risks that SMRs, CCS, and hydrogen-burning turbines present.

Q. What path has led you to propose that a renewable energy park in the Pueblo area is a reasonable option for replacing the capacity and energy from the Comanche coal plant?

A. When I began my work for this proceeding, I was thinking about proposing that a new stand-alone battery storage facility be studied as a way to reduce reliability-related concerns associated with the concentration of solar in the Pueblo area. But then I read the December 2024 Energy Innovation report on energy parks and I reread an earlier report, also by Energy Innovation, on industrial thermal batteries.[134] These reports helped me recognize that there are other resources that could be added to improve the benefits from the stand-alone battery storage facility I was initially considering. These additional resources are flexible demands and thermal battery storage.

Through my 51-year career I have become familiar with the benefits of flexible demands, intermittent renewable resources, and fast responding battery storage capacity. For example, more than two decades ago, I learned about the benefits for utility resource planning and customers' bills from load shifting and what was being called "demand or load response," where large customers would be paid to agree to reduce their loads on the grid when called upon by a utility or ISO. More recently, I've followed how the massive increases in battery storage capacity in both CAISO and ERCOT, with fast-responding solid-state controls, have improved the reliability of those grids in both normal and abnormal weather conditions.

[134] Jeffrey Rissman & Eric Gimon, Energy Innovation Pol'y & Tech. LLC, *Industrial Thermal Batteries: Decarbonizing U.S. Industry While Supporting a High-Renewables Grid* (2023), https://energyinnovation.org/report/thermal-batteries-decarbonizing-u-s-industry-while-supporting-a-high-renewables-grid/.

Q. What is your second recommendation for modifying the Carbon Free Future Development proposal?

A. For the remaining funds related to the Carbon Free Future Development policy, I recommend the Commission limit any funds PSCo seeks to spend on any of the three technology options I have discussed, i.e., an SMR, a turbine with CCS, and a hydrogen-burning turbine. Specifically, I recommend the Commission limit PSCo to only spending funds related to these technologies in the following ways: (1) following industry developments and proposals in other states, Canada, and overseas; and (2) conducting internal analyses of the technical and financial viability of each technology. Given the very speculative statuses of all three of these technologies, no funding for initial implementation should be allowed at this time.

Q. Are there any other technologies you believe the Company should be directed to use the Carbon Free Future Development policy to investigate?

A. Yes. Geothermal and long-term battery and thermal storage alternatives.

Q. And what is your third recommendation for modifying the Carbon Free Future Development proposal?

A. Given the importance of selecting future carbon free technologies and potentially large to huge costs for ratepayers, I recommend that the membership and process of the Advisory Committee be designed to ensure that voices from all perspectives be heard. In particular, the Advisory Committee should include a more diverse range of Pueblo community members. I think we can agree that companies seeking funding are going to emphasize the positives of their proposed projects. Those skeptical of proposed technologies should be given an opportunity to be heard as well, or the results of the process will be questioned. Finally, there also should be non-governmental members of the committee who are PSCo ratepayers. They and their descendants are going to have to bear the costs of future technologies, so their voices deserve to be heard as well.

Q. Does this conclude your Answer Testimony?

A. Yes.