EPRI Comments on the U.S. Environmental Protection Agency's "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule"

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EPRI submits the enclosed comments to the United States Environmental Protection Agency (EPA) on the proposed rules titled "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule." EPRI thanks EPA for the opportunity to comment.

EPRI is an independent, nonprofit organization for public-interest energy and environmental research. Founded in 1972, EPRI brings together member organizations, EPRI's scientists and engineers, and other leading experts and stakeholders to work collaboratively on solutions to the challenges of electric power and broader energy systems. This collaborative research, development, and deployment spans nearly every area in the generation, delivery, and use of electricity, including reliability, efficiency, health, safety, and the environment.

Specifically related to these proposed rules, EPRI has been involved in decarbonization-related research for more than five decades, with economic and integrated assessment analyses and expertise related to emissions projections, decarbonization pathways, mitigation technologies, and climate science and economics. EPRI is leading global collaboration surrounding the transition to a low-carbon energy system through a pair of industry-level initiatives—the Low-Carbon Resources Initiative and Climate READi. Technology assessment, development, and innovation have been central to EPRI since its inception. These comments on EPA's proposed rules and regulatory impact analysis (RIA) reflect EPRI's research expertise and are technical rather than legal in nature. In assembling these comments, EPRI draws upon decades of experience and expertise in wide-ranging research efforts associated with:

- Generation technology cost and performance assessment
- Low-carbon electric generation technologies and energy carriers such as clean hydrogen, bioenergy, and renewable natural gas
- Carbon capture, utilization, and storage (CCUS) and cofiring fuels at power plants
- Modeling the electric power sector, energy systems, and linkages to the broader economy
- Resource adequacy, reliability, and resiliency tools and data
- Air quality models, measurements, and health effects
- Climate impacts and the social costs of carbon and other greenhouse gases
- Energy equity and environmental justice

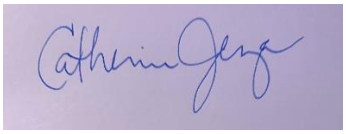
EPRI's comments are organized into several sections that parallel the structure of the proposed rules, RIA, and supporting material. The first four sections comment on the proposed rules, while the latter two address the supporting documents:

1. Subcategorization
2. Best System of Emissions Reduction (BSER)
    a. Carbon Capture and Storage
    b. Hydrogen
    c. Natural Gas Cofiring at Coal Plants
3. System Impacts
4. State Plans and Trading
5. Regulatory Impact Analysis (RIA)
6. Technical Support Documents (TSD)

Energy-economic model results referenced in these comments, from EPRI's US-REGEN model and others, provide cost-optimized pathways for energy supply and demand given alternative assumptions about technology costs, markets, and policies. Model results should be interpreted as indicative rather than predictive because of uncertainties associated with policy implementation, siting and permitting, scaling supply chains and workforce, readiness for emerging technologies, and ramping up infrastructure investments (for example, transmission).

Model results are valuable complements to historical data, given how future power systems may differ from those of the past. For instance, changing resource mixes, load shapes from electrification, fuel prices, policies, and other drivers may alter regional investments and operations.

Modeling studies are typically scenario analyses designed to understand alternative technology pathways to meet policy goals, which makes it important to understand the underlying model inputs and scenario assumptions to properly contextualize the results. Model results should not be interpreted as feasibility assessments, but instead as exercises to investigate the economic, technical, and market trade-offs associated with proposed policy and regulatory targets. Models typically do not address supply chain and infrastructure ramp-up constraints to deploying new technologies at scale.



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Executive Summary

EPA and EPRI share a fundamental interest in advancing energy technologies for the benefit of customers, communities, and the environment. As an independent, nonprofit energy and environment research organization that collaborates with industry and government stakeholders worldwide to advance its society-focused mission, EPRI is uniquely qualified to provide objective, technology-agnostic comments and recommend courses of action, where requested in EPA's proposal. This response reflects the latest insights from EPRI's industry-leading experts and is informed by more than 50 years of research and development involving hundreds of energy companies, technology developers, academic institutions, and government entities.

A consumer-centered clean energy transformation rests on balancing competing priorities, accounting for wide-ranging implications of resource decisions, and determining feasible, yet intentional timing. As EPA states, the electric sector is a key pillar of economy-wide decarbonization efforts, both through direct emissions reductions and its support of end-use decarbonization (Rules, p. 14), making continued progress in electric sector decarbonization foundational to emission reduction across the U.S. economy.

The combined effects of the proposed rules would impact approximately 40% of total U.S. dispatchable power generation capacity. To maintain reliability through the clean energy transition, the power sector would need to address the resulting dispatchable generation impact with similarly flexible resources. Phased approaches that involve full-scale demonstrations prior to widespread deployment are critical to a reliable and affordable transition.

Through its review of the proposed rules, EPRI has developed technical recommendations with a focus on maintaining reliability, affordability, and equity for consumers through the clean energy transition. Four overarching themes emerged in the process:

1. **Carbon capture and sequestration (CCS):** A phased approach to CCS deployment provides opportunities to address key uncertainties around cost, performance, and operation, and achieve n^{th}-of-a-kind cost. (Sections 1 and 2).
2. **Hydrogen**: A large-scale infrastructure buildout is necessary to support power generation. (Sections 1 and 2).
3. **Modeling:** The rules' assumptions do not reflect the impacts on the power sector, environment, customers, and communities. (Section 5).
4. **Broader impacts:** There are wide-ranging energy system and societal effects that need to be understood to inform the proposed rules. (Sections 3 and 5).

The emerging technologies identified in the rules—CCS and hydrogen—have seen little to no deployment at scale so far and depend on new infrastructure with impacts to project timelines, feasibility, and costs beyond the scope of EPA's analysis. Although the proposed rules treat CCS and hydrogen similarly, they are two very different technologies that are not comparable in their greenhouse gas (GHG) reduction impacts or timelines to scale. These emerging resources require entire new supporting infrastructure (that is, production, pipelines, and storage for hydrogen; pipelines and storage for CCS), and should be considered in their entirety to fully understand the potential benefits, costs, and deployment challenges and opportunities.

1. CCS: A phased approach to CCS deployment provides opportunities to address key uncertainties around cost, performance, and operation, and achieve n^{th}-of-a-kind cost.

The power industry's experience with full-scale construction, deployment, and operation of CCS technology is nascent. A phased approach to CCS deployment is needed to allow further demonstrations in order to answer key questions around costs, development, and operation prior to industry-level deployment.

CCS is an important technological option to support economy-wide decarbonization. As with all emerging technologies, early experience with existing power generation CCS facilities has presented challenges. Particular difficulties with CCS surround cost, operation, availability, and achieving a 90% capture rate. The timing and scale of CCS deployment depend on factors such as siting, permitting, construction, and operations, which are uncertain and are not solely dependent on the utility industry (Section 2.1). The rules use optimistic assumptions about cost, project schedule, operational flexibility, regional viability for CCS, and accessibility of Inflation Reduction Act (IRA) incentives (Section 2.2).

> **Costs:** The rules' cost assumptions are not representative of current trends. The estimates do not adequately account for uncertainty associated with early deployment of these emerging generation options and assume n^{th}-of-a-kind costs are within reach. Potential delays in beginning CCS projects or development of the associated carbon dioxide (CO_2) transport and storage infrastructure may impact companies' ability to mitigate customer costs of the rules through IRA's production-based incentives.
>
> **Operational experience:** Research has shown that adding CCS to operating facilities reduces flexibility, potentially impacting steam pressures, ramping rates, and minimum load (Section 2.2). Prior to widescale deployment, it is important to assess the ability of CCS-equipped resources to follow variable load, analyze real-world water and resource requirements, capture at the target rate, and quantify the costs and performance of startup, shutdown, operations, and maintenance. Accounting for these operational uncertainties may alter the costs, emissions, and power system impacts of the rules.
>
> **Regional differences:** Access to and feasibility of CO_2 transport and storage infrastructure varies across regions. Understating the impacts of regional differences can lead to inaccurate cost estimates, particularly for retrofits of existing plants and generation facilities opting for alternate compliance pathways.

2. Hydrogen: A large-scale infrastructure buildout is necessary to support power generation.

Hydrogen power generation has the potential to play an important role as part of a net-zero economy. Although hydrogen is an emerging resource and a growing focus of pilot and demonstration efforts, the technology—and its key supporting components—have not been demonstrated at the scale envisioned in the rules (Section 2.3). Low-GHG hydrogen is not available at commercial scale today, and there are not markets that recognize production characteristics consistent with the rules. Deployment at the scale proposed by the rules—nearly 770 trillion Btu of hydrogen

demand by 2035 in one power sector scenario, representing an increase of more than two-thirds of today's production (Section 5.1)—would require new infrastructure, markets, policies, and technologies.

Low-GHG hydrogen production scaling: Though hydrogen is a part of the current U.S. energy economy, low-GHG fuel suitable for power generation under the rules is not at scale today. Low-GHG hydrogen production would need to scale to the level necessary to support the future power system and other potential applications. Accounting for these scaling dynamics may alter the costs and compliance pathways under the rules.

Hydrogen economy: Hydrogen power generation depends on extensive supporting infrastructure that does not exist today. Beyond the production of low-GHG hydrogen, which EPRI estimates to cost $3–5 per kilogram of hydrogen by 2030 before tax credits, additional costs associated with the hydrogen transport, storage, and delivery could add between $0.30/kg-$H_2$ and $3.30/kg-$H_2$, according to U.S. Department of Energy estimates. Increased hydrogen costs could place additional costs pressure on consumers through the transition envisioned by the rules.

Production: Producing low-GHG electrolytic hydrogen to achieve emission goals would require access to substantial additional low-emission electricity. The cost and timing of this scale-up could be complicated by other demands for low-emission electricity and siting, permitting, interconnection, and other deployment issues.

Hydrogen use in the power sector: The nascent state of hydrogen demonstrations in electricity generation, the current absence of low-emitting hydrogen production, and limited industry experience with hydrogen project development and operation make the prospect of deploying hydrogen-powered generation reliably and affordably an uncertain proposition in the near term. In addition, hydrogen blending readiness across the current U.S. natural gas fleet varies, and many aspects still need to be studied, including understanding operation profiles, performance and flexibility, retrofit needs and costs, and potential impacts on other air emissions, such as nitrogen oxides (NOx).

Energy and production costs: The low levelized hydrogen costs assumed by the RIA conflict with analyses by EPRI and others indicating regional variation and uncertainty around future costs, which are expected to increase when tax credits are not available. From a practical application standpoint, hydrogen's economics and high marginal cost relative to other resources may mean that it is used with lower capacity factors—not over 50%, as the rules suggest.

3. Modeling: The rules' assumptions do not reflect the impacts on the power sector, environment, customers, and communities.

Modeling in the Regulatory Impact Analysis (RIA) has limitations that likely result in understated compliance costs, associated impacts of the rules, and uncertainty (Sections 5.1 through 5.4).

Modeling and assumptions should be revised to better capture the costs, benefits, and uncertainty associated with the proposed rules and the environmental and societal impacts of compliance.

Power sector: Power sector modeling—the basis of the RIA—should be modified to provide better representations of power systems and market dynamics. For instance, the current modeling

likely overstates renewables deployment and understates firm capacity and energy storage deployment (Section 5.1).

Technology modeling and assumptions: Technology modeling and cost assumptions assume a n^{th}-of-a-kind costs, do not account for the full infrastructure needed to support CCS and low-carbon hydrogen, reflect aggressive deployment timelines, and do not reflect the uncertainty associated with these technologies.

Air quality: RIA modeling to calculate air quality health benefits should consider a more robust analysis of uncertainty, the full effects of co-pollutants, and potential air quality impacts of the chemicals used in carbon capture processes.

Electrification growth: Anticipated end-use electrification trends and their impacts on electricity demand growth, load profiles, and flexible demand may impact the costs and emissions associated with the rules. Key factors to consider include electricity demand and supply from electrolytic hydrogen production.

Climate and net benefits: The social cost of carbon (SCC) methodology and estimates—critical inputs into the climate benefit calculations in the RIA—should be revised to produce scientifically grounded and robust climate and net benefits estimates.

Customer and community impacts: The Environmental Justice (EJ) Impacts section of the RIA, which analyzes the effects of the proposed rules on disadvantaged communities, should be augmented to include considerations beyond air quality, quantify cumulative impacts, and assess the full proposed rules rather than a subset of the standards.

4. Broader Impacts: There are wide-ranging energy system and societal effects that need to be understood to inform the proposed rules.

Balancing affordability, reliability, sustainability, and equity requires accurate information about potential changes affecting many facets of the energy system. The proposed rules provide opportunities to advance the transition in some areas while introducing new challenges in others. In addition to characterizing the rules' impacts on costs and emissions, there may be additional consequences on reliability, resiliency, water, land, energy security, and other energy system and societal outcomes. Understanding these impacts requires more in-depth analysis.

Resource adequacy and reliability: A more robust analysis of resource adequacy is needed that considers grid operational reliability impacts utilizing an adjusted approach, set of assumptions, and metrics. Include probabilistic assessments, such as loss of load expectation, expected unserved energy, or loss of load hours (Section 3.2).

Water requirements: Water consumption and wastewater management should be considered when evaluating CCS and hydrogen as BSER. CO_2 capture systems require significant amounts of water and carbon storage systems may require the extraction, treatment, and disposal of saline groundwater. For hydrogen, electrolytic processes require water resources – not only high-purity

water for the direct production of hydrogen, but also for balance-of-plant systems such as cooling water.

EPRI's technical recommendations are discussed in detail in the pages that follow.

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List of Abbreviations

45Q	Inflation Reduction Act tax credits for captured CO_2
45V	Inflation Reduction Act tax credits for hydrogen
111	Section 111 of the Clean Air Act
111(b)	new source performance standards under Section 111 of the Clean Air Act
111(d)	existing source performance standards under Section 111 of the Clean Air Act
AACE	Association for the Advancement of Cost Engineering
AEO	Annual Energy Outlook
ASTM	American Society for Testing and Materials
BECCS	bioenergy with carbon capture and storage
BenMAP	Environmental Benefits Mapping and Analysis Program
BSER	Best System of Emissions Reduction
CCS	carbon capture and storage
CDC	Centers for Disease Control and Prevention
CDR	carbon dioxide removal
CF	capacity factor
CO_2	carbon dioxide
DAC	direct air capture
DLN	dry-low NOx
DOE	U.S. Department of Energy
EAV	equivalent annualized values
EGU	electric generating unit
EIA	U.S. Energy Information Administration
EJ	environmental justice
EPA	U.S. Environmental Protection Agency
EPC	engineering, procurement, and construction
EPRI	Electric Power Research Institute
ESPS	existing source performance standard
FEED	Front-End Engineering Design
FGD	flue gas desulfurization
FOAK	first-of-a-kind
gal	gallon
GDP	gross domestic product
GHG	greenhouse gas
H_2	hydrogen
HRSG	heat recovery steam generator
IIJA	Infrastructure Investment and Jobs Act
IPM	Integrated Planning Model
IRA	Inflation Reduction Act of 2022
ISO	International Organization for Standardization
IUA	integrated uncertainty analysis
kg	kilogram
LCOE	levelized cost of electricity
LNG	liquified natural gas
LOLE	loss of load expectation
MW	megawatt

MWh	megawatt-hour
NASEM	National Academies of Sciences, Engineering, and Medicine
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NGCC	natural-gas combined-cycle
NGGT	natural gas combustion turbine
NOAK	n^{th}-of-a-kind
NSPS	new source performance standard
O&M	operations and maintenance
OEM	original equipment manufacturer
OMB	Office of Management and Budget
PC	pulverized coal
PEM	proton exchange membrane
PM	particulate matter
PRM	planning reserve margin
PV	present value or photovoltaic
R&D	research and development
RIA	regulatory impact analysis
RULOF	remaining useful life and other factors
SCC	social cost of carbon
SCF	standard cubic feet
SCR	selective catalytic reduction
SMR	steam methane reforming
TRL	technology readiness level
TSD	technical support document
US-REGEN	U.S. Regional Economy, GHG, and Energy

1. Subcategorization

Section Summary: EPRI suggests establishing subcategories and best system of emissions reduction (BSER) that use the best-available technical knowledge, account for variability within source categories, characterize uncertainty, and clarify ambiguities in the rules. Greater clarity should be provided on the definition of the capacity threshold for applicable gas-fired units that would be subject to requirements for existing gas, given how this threshold has significant implications for the applicability of these rules and their emissions and cost impacts. Subcategories should be designed to reflect cost-effective abatement while preserving system reliability and flexibility, which includes considering regional differences and actual operating conditions.

Provide greater clarity on the definition of the 300-MW threshold for applicable gas-fired capacity that would be subject to 111(d) requirements for existing gas.

The capacity threshold definition is ambiguous as currently proposed. The rules should explicitly define how to determine the 300-MW threshold and provide additional detail on how to make this determination on a combined-cycle plant.

In the proposed rules, there is ambiguity in the description about whether the capacity threshold includes the nameplate capacity of individual combustion turbines or aggregate output (for example, when the combustion turbine is in a combined cycle of both the combustion turbine nameplate MWs and the steam turbine MWs attributable to the combustion turbine). If the applicable capacity includes the steam turbine, there is also ambiguity about accounting for capacity from the use of duct burners. Clarification is also warranted on how combined-cycle combustion turbines that can operate in either combined-cycle mode or open-cycle mode are to be treated with regard to these thresholds. A memo[1] issued on June 12, 2023 clarifies some of the applicability requirements in 40 CFR part 60, subpart UUUUb; however, this document does not update the calculation of applicable and exempt capacity.

IPM modeling projections understate the existing gas capacity impacted by the rules. Units impacted should be determined based on existing generation capacity.

The rules used IPM modeling to project 36.8 GW of current natural-gas-fired electric generating unit (EGU) installed capacity would be impacted by subcategory capacity threshold of 300 MW in 2035 (Rules, p. 12[2]; Resource Adequacy TSD, p. 7). This does not account for units that were projected via the model to run less than 50% capacity factor, therefore understating the overall number of impacted units. Even though CCS or hydrogen co-firing are not required, these units are still impacted by the rule given that they will no longer have the option to operate greater than a 50% capacity factor without retrofitting.

Existing generation utilization data should be used to accurately account for the impacted units in this subcategory. EPRI has used available data from https://www.epa.gov/egrid/download-data eGRID2021, assuming that the 300-MW cutoff included both individual combustion turbine MWs and approximate attributable steam turbine MWs (consistent with EPA's June 12, 2023 memo) with greater than a 50%

[1] U.S. EPA (2023). Applicability of Emission Guidelines to Existing Stationary Combustion Turbines: FAQs Memo to the Docket (link).
[2] Page numbers referenced in these comments refer to the PDF of the proposed rules, which was made available on May 11, 2023.

capacity factor in the 2021 data. This assessment yielded >160 GW of natural gas EGU capacity subject to the rules, rather than the 36.8 GW in the rules. In 2021, this capacity represented ~919 GWh of generation out of a total of 1,474 GWh of natural gas generation, which is roughly 62% of the total gas generation and 23% of total electricity generation.

Emission rate standards for existing gas turbines should consider actual operating conditions, such as variances from the International Organization for Standardization (ISO) rated conditions, varying operating loads, and equipment degradation.

The CO_2 emissions rate standard of 770 lb-CO_2/MWh-gross is only achievable for the newest gas turbine models in a combined-cycle configuration at full load operations at ISO-rated conditions. In actual applications, ISO-rated conditions (that is, gas turbines operating at sea level at 59 °F) are rarely encountered. This can have a material effect on emissions rates per MWh produced. In addition, gas turbines are often not at full load operating conditions but increasingly operate flexibly to accommodate additional renewable generation. Another compounding factor is that fouling and wear can lead to increased emission rates compared to the achievable rates for the new gas turbines. 2021 emissions from EPA's eGrid2021 show that 4 out of 119 plants with capacity factors greater than 50%, achieved the proposed limit.

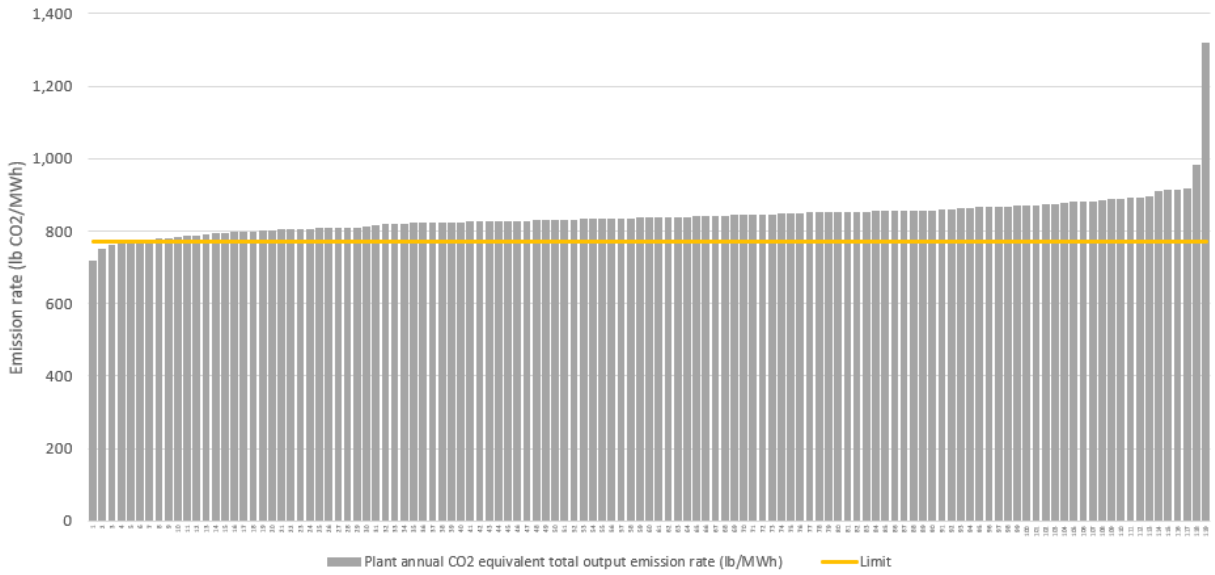


Figure 1. 2021 CO_2 emission rates for gas turbines with capacity factors greater than 50%. Data comes from EPA's eGrid2021.[3]

Actual operating conditions should be considered when setting rate standards, including the necessary flexible operation of future combined-cycle power plants and the technical feasibility of achieving this proposed limit under these operating conditions, particularly those that have maximum running hours in summer periods when emission rates will be increased because of warm ambient conditions.

[3] https://www.epa.gov/egrid/download-data eGRID2021 .

The rules also set a 770–900 lb-CO_2/MWh-gross standard for base load EGUs with a rating less than 2,000 MMBtu/h. Although the upper limit is readily achievable by large, high-efficiency gas turbines in combined-cycle configurations, smaller units may not be able to readily achieve this emission rate. It is recommended that potential impacts of these standards for smaller power plants be examined.

The low load subcategory (that is, with capacity factors less than 20%) sets limits based on fuel type at 120–160 lb-CO_2/MMBtu. These standards appear appropriate for natural gas but are lower than the standard emission factors from EIA[4] for distillate oils and may preclude oil firing, which is an important option for winter resilience of the gas fleet.

The intermediate load subcategory (that is, with capacity factors between 20% and 50%) sets out a standard of 1,150 lb-CO_2/MWh-gross. This is readily achievable for large, modern gas turbines in simple-cycle configurations (>150MW) but may not be achievable for mid-size to smaller heavy-duty gas turbines. The implied heat rate for this CO_2 limit is slightly below 10,000 BTU/kWh, and many E- and B-class gas turbines in simple-cycle configurations have heat rates above this value.

Subcategorizations for existing coal-fired steam units should account for announced plans of plant owners and operators to ensure cost recovery.

Many utilities have announced retirement dates for existing coal units because of economic drivers, other regulations and legislation, or voluntary company emissions commitments. As the rules state, "Subcategorizing on the basis of operating horizon is consistent with a central characteristic of the coal-fired power industry that is relevant for determining the cost reasonableness of control requirements: A large percentage of the industry has announced, or is expected to announce, dates for ceasing operation, and the fact that many coal-fired steam generating units intend to cease operation affects what controls are 'best' for different subcategories" (Rules, p. 397). This dependence of the cost of controls on the amortization period means that plants with near-term announced retirements would have less time to recover capital costs, which would alter their cost effectiveness. Based on announced retirements, Figure 2 shows how a large fraction of the U.S. coal fleet has either retired or plans to retire in the next decade—resulting in less than 90 GW of capacity installed after 2035.

[4] EIA (2022). Carbon Dioxide Emissions Coefficients (link).

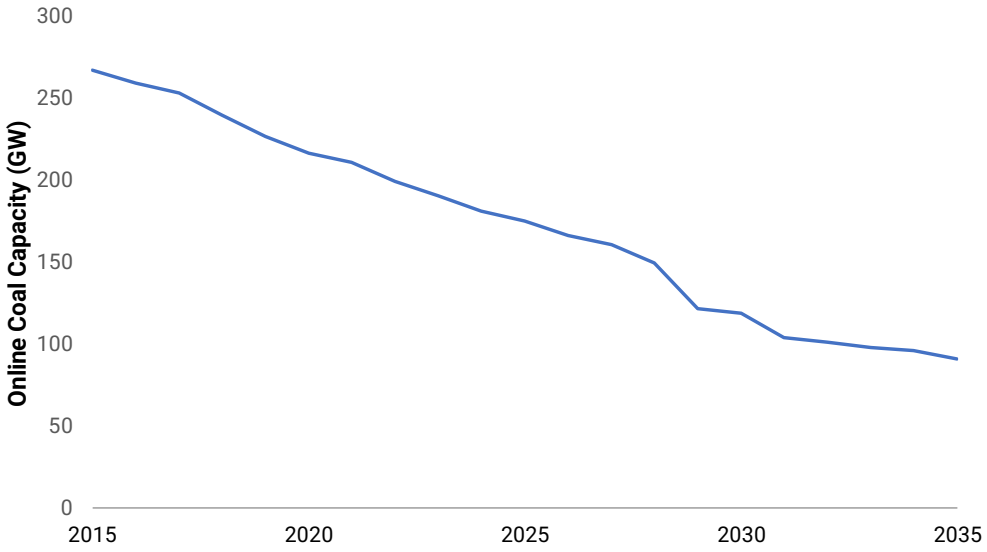


Figure 2. Coal capacity announced retirements (net summer capacity). Coal capacity online comes from a comprehensive database of announced retirements compiled by EPRI, which was last updated in June 2023.

Regional variation and uncertainty about future operating conditions should be considered in developing subcategories and cost estimates.

The costs of emissions controls can change significantly based on the assumed capital recovery period, utilization, and other unit-specific features. Distinguishing subcategories based on these attributes can help account for these differences, which is done in several areas of the rules. The proposed new and existing source performance standards include subcategories that are based on characteristics such as size, operating frequency, and planned retirement dates. The proposed rules note that EPA is "soliciting comment on a number of variations to the subcategories and BSER determinations," including the "capacity factor threshold for inclusion" (Rules, p. 24). Instead of using fixed capacity factor thresholds that do not vary by region or time, several factors can be used to develop these capacity-factor-based subcategories and cost estimates for control technologies—including the economics of control technologies to contribute toward systemwide mitigation and detailed prospective modeling of electric sector capacity planning under a range of scenarios. For instance, EPRI modeling[5] of U.S. power system investments and emissions indicates that future investment and utilization are scenario- and context-specific (Figure 3):

- Capacity factors of natural-gas combined-cycle (NGCC) units vary by region (because of fuel costs, existing system mixes, renewable resources, and policies) and by assumed policies (because NGCC capacity plays different functional roles depending on decarbonization targets).

[5] EPRI (2022). Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis. EPRI Report 3002024882 (link). Bistline and Young (2022). The Role of Natural Gas in Reaching Net-Zero Emissions in the Electric Sector. Nature Communications, 13: 4743 (link).
Bistline et al. (2018). Electric Sector Policy, Technological Change, and U.S. Emissions Reductions Goals: Results from the EMF 32 Model Intercomparison Project. Energy Economics, 73: 307–325 (link).

This variation aligns with historical NGCC capacity factors, which exhibit differences by region, plant age, and time (Figure 4).

- Carbon-capture-equipped gas tends to be deployed with higher capacity factors between 55% and 85% depending on the region and scenario.
- Hydrogen-fired plants under these scenarios vary in their deployment but generally tend to run with lower capacity factors between 10% and 35% because of their higher short-run marginal costs than traditional gas-fired plants. However, this utilization could change in the presence of large production-based incentives, including the tax credits provided through the Inflation Reduction Act's (IRA's) 45V.

These figures highlight regional variation because of differences in fuel costs, existing system mixes, renewable resources, policies, and other factors that influence mitigation costs and the roles of specific electric sector resources.

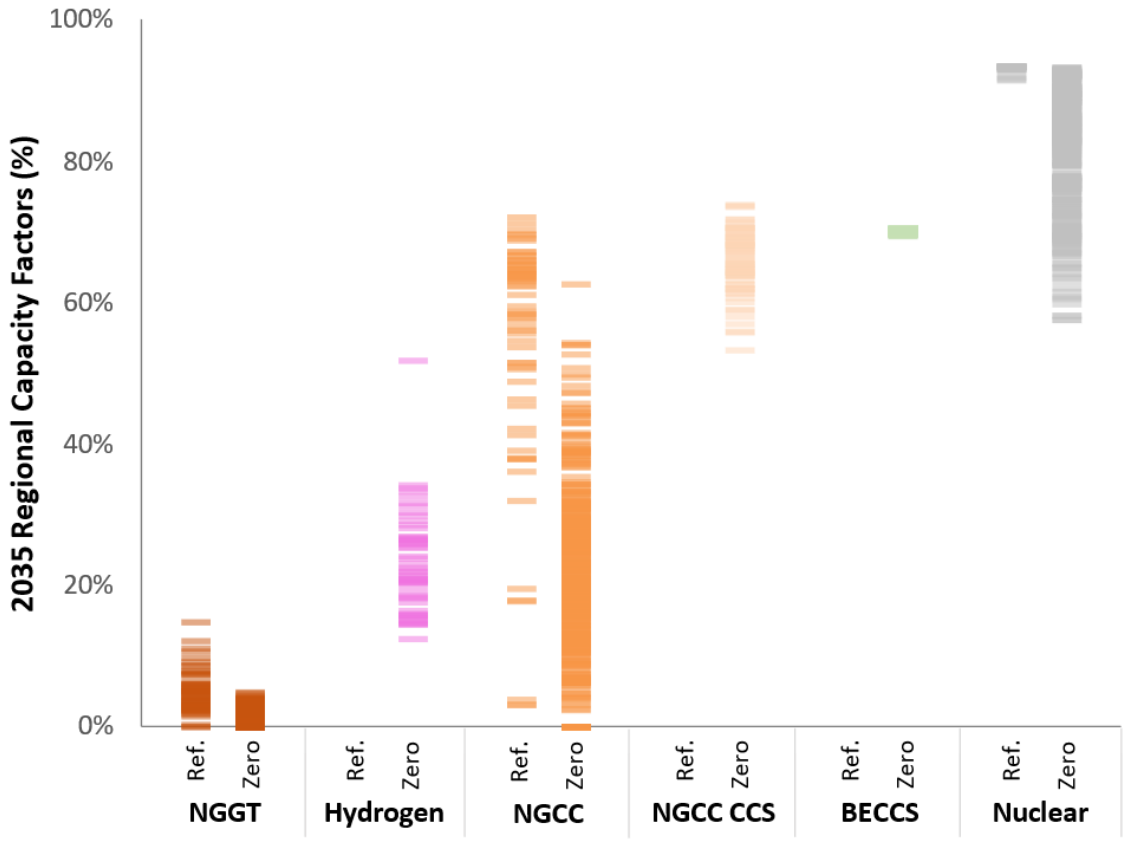


Figure 3. Modeled regional capacity factors by technology across different policy scenarios (reference scenario with on-the-books policies and a net-zero power sector scenario). Dashes show capacity factors across regions and scenarios.[6]

[6] Bistline and Young (2022). The Role of Natural Gas in Reaching Net-Zero Emissions in the Electric Sector. Nature Communications, 13: 4743 (link).

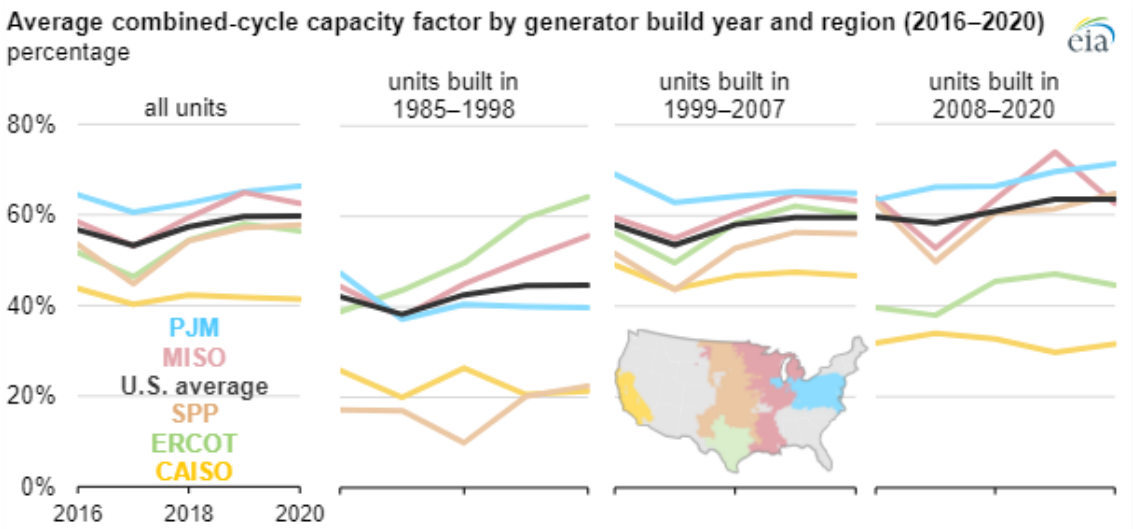


Figure 4. NGCC capacity factors by region and age over time. Source: U.S. Energy Information Administration (2021).[7]

In contrast to this variation, subcategories for the new and existing source performance standards (ESPS) for fossil-fuel-fired combustion turbines use fixed capacity-factor-based thresholds that do not vary across region or time.

The low-load subcategory for combined-cycle and simple-cycle combustion turbines is consistent with their expected future role in the modeling literature on electric sector decarbonization. This could help balance emissions reductions with reliability and affordability considerations as coal capacity retires, electrification increases, and deployment of renewables accelerates.

EPRI research supports such subcategories if the threshold is informed by analysis, defined clearly, and recognizes regional differences. EPRI modeling suggests that lower-utilization resources can provide dispatchable capacity for extended periods, which can contribute to keeping power systems affordable, reliable, and resilient during the transition—even while operating with lower capacity factors.[8] This finding is consistent with the broader energy systems decarbonization literature, though questions remain about wholesale and retail market design changes that might become increasingly valuable as systems approach net-zero emissions levels.[9]

Modeling studies indicate that natural-gas-fired generation can lower the cost of electric sector decarbonization—a result that is robust to a range of sensitivities—when carbon removal is allowed under policy, which lowers marginal abatement costs of reaching net-zero power sector CO_2 emissions by over

[7] EIA (2021). Natural-Gas Combined-Cycle Plant Use Varies by Region and Age (link).
[8] Bistline and Young (2022). The Role of Natural Gas in Reaching Net-Zero Emissions in the Electric Sector. Nature Communications, 13: 4743 (link).
Bistline and Blanford (2021). Impact of Carbon Dioxide Removal Technologies on Deep Decarbonization of the Electric Power Sector. Nature Communications, 12: 3732 (link).
Woollacott (2020). A Bridge Too Far? The Role of Natural Gas Electricity Generation in U.S. Climate Policy. Energy Policy, 147: 111867 (link).
[9] Bistline and Blanford (2021). The Role of the Power Sector in Net-Zero Energy Systems. Energy and Climate Change, 2: 100045 (link).
Ela et al. (2021). Electricity Market of the Future. IEEE Power and Energy Magazine, 19 (link).

two orders of magnitude.[10] System needs are evolving over time as the generation mix changes, which means that units could be operated differently in the future, with regional variation. The value of natural gas generally shifts from providing energy to providing capacity over time and with deeper decarbonization, and capacity factor changes exhibit strong regional variation (Figure 3).

[10] Bistline and Young (2022). The Role of Natural Gas in Reaching Net-Zero Emissions in the Electric Sector. Nature Communications, 13: 4743 (link).

2. Best System of Emissions Reduction

2.1. Cost Estimates

Section Summary: Attention to the dynamics of technological change—including research, development, demonstration, and deployment for emerging technologies—is important to advance an affordable and reliable clean energy transition. These factors should be included in the rules and their supporting analysis. Cost estimates for emerging technologies may be understated if demand for equipment, materials, and labor increase during a scale-up over a limited time horizon. Metrics for comparing the costs of control technologies in the proposed rules may be incomplete representations of the costs and benefits across resource alternatives, and their estimates may understate uncertainty—especially given the limited experience at scale for emerging technologies related to the rules.

Expectations and estimates of future costs of emerging technologies, such as CCS and hydrogen, should be informed through various complementary methods, including reviews of historical experience with similar or analogous technologies, detailed bottom-up technoeconomic analysis, and expert elicitations.[11]

Previous industry experience with less complicated (that is, lower capital costs, fewer components, and less off-site integration of infrastructure) efforts involving the installation of flue gas desulfurization (FGD) and selective catalytic reduction (SCR) technologies resulted in increased costs over the short term before costs declined (Figure 5).[12] Capacity planning and energy systems models that analyze potential deployment of CCS in economic scenarios may not account for the first projects and their costs compared to the lowest potential cost achieved when technology reaches scale. Experience from FGD and SCR installations suggest that the cost reductions to nth-of-a-kind (NOAK) may not occur if accelerated construction for policy compliance does not provide enough opportunity for cost savings through incremental learning-by-doing and other serialized learning mechanisms for subsequent projects.[13] Furthermore, energy technologies with high design complexity and lack of standardized design as well as larger and less modular designs have been found to progress at a relatively slower pace, which may alter projected cost and performance assumptions for CCS and hydrogen.[14] In addition, whether anticipated cost reductions at higher deployment are driven by learning-by-doing, economies of scale, or other factors may alter the cost implications of rapid scaling.[15]

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[11] Rai, Victor, and Thurber (2010). Carbon Capture and Storage at Scale: Lessons from the Growth of Analogous Energy Technologies. Energy Policy, 38(8): 4089–4098 (link).
van Ewijk and McDowall (2020). Diffusion of Flue Gas Desulfurization Reveals Barriers and Opportunities for Carbon Capture and Storage. Nature Communications, 11(1): 4298 (link).
EPRI (2022). *TAGWeb*. EPRI Report 3002025747 (link).
Bistline (2014). Energy Technology Expert Elicitations: An Application to Natural Gas Turbine Efficiencies. Technological Forecasting and Social Change, 86: 177–187 (link).
[12] Rubin et al. (2007). Use of Experience Curves to Estimate the Future Cost of Power Plants with CO_2 Capture. International Journal of Greenhouse Gas Control, 1(2): 188–197 (link).
[13] NETL (2013). Quality Guidelines for Energy System Studies: Technology Learning Curve (FOAK to NOAK). National Energy Technology Laboratory Report DOE/NETL-341/081213 (link).
[14] Wilson et al. (2020). Granular Technologies to Accelerate Decarbonization. Science, 368(6486): 36–39 (link).
Malhotra and Schmidt (2020). Accelerating Low-Carbon Innovation. Joule, 4(11): 2259–2267 (link).
[15] Nemet (2019). How Solar Energy Became Cheap: A Model for Low-Carbon Innovation. Routledge (link).
Taylor, Rubin, and Hounshell (2005). Regulation as the Mother of Innovation: The Case of SO_2 Control. Law & Policy, 27(2): 348–378 (link).

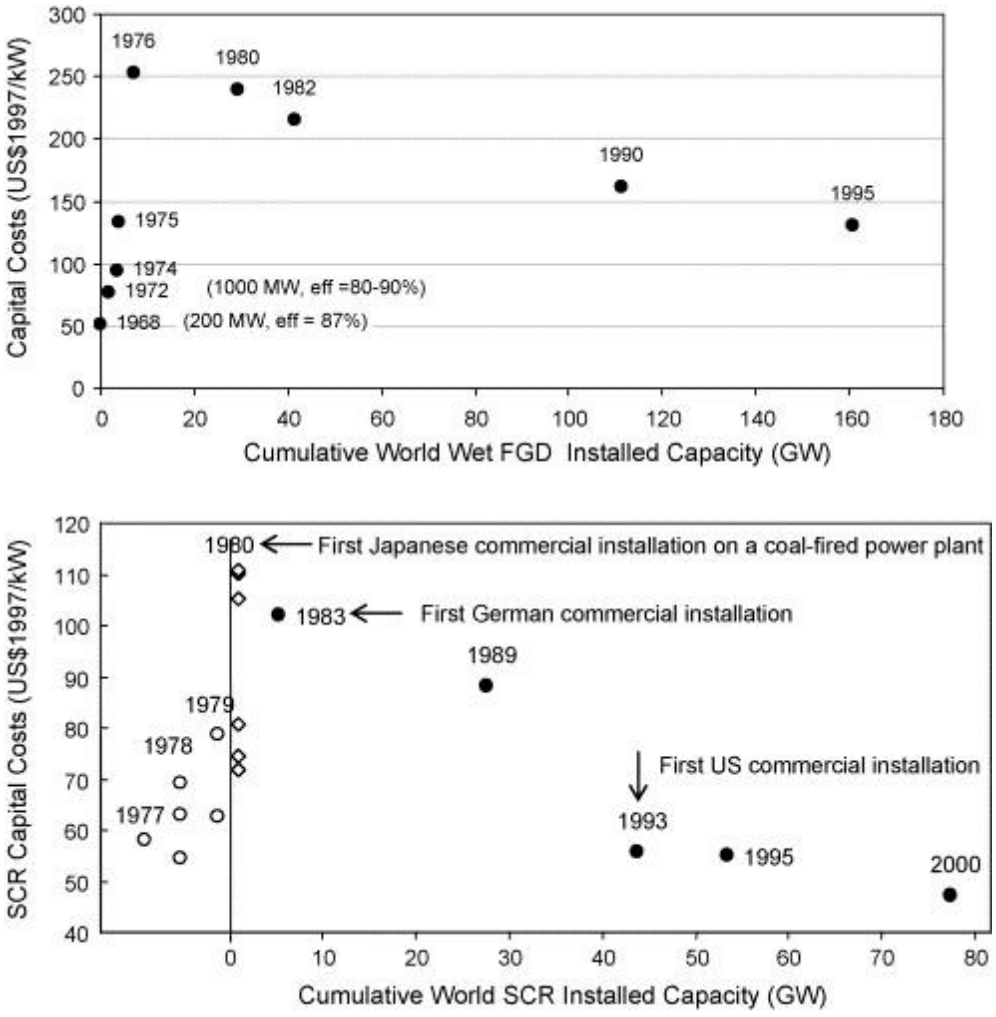


Figure 5. Historical capital cost trends for wet limestone FGD systems and SCR systems at a new coal-fired power plants in the U.S. (500 MW, 90% SO_2 capture, 80% NOx reduction), including cost studies conducted during (FGD) or prior to (SCR) the period of early commercial applications. Figures come from Rubin et al. (2007).

In addition to the possibility of an inverted U-shaped cost curve, another common feature of experience curves for energy technologies is greater uncertainty about costs for early deployment periods (see the gray shaded band in Figure 6), which itself can be a challenge for investment and deployment.

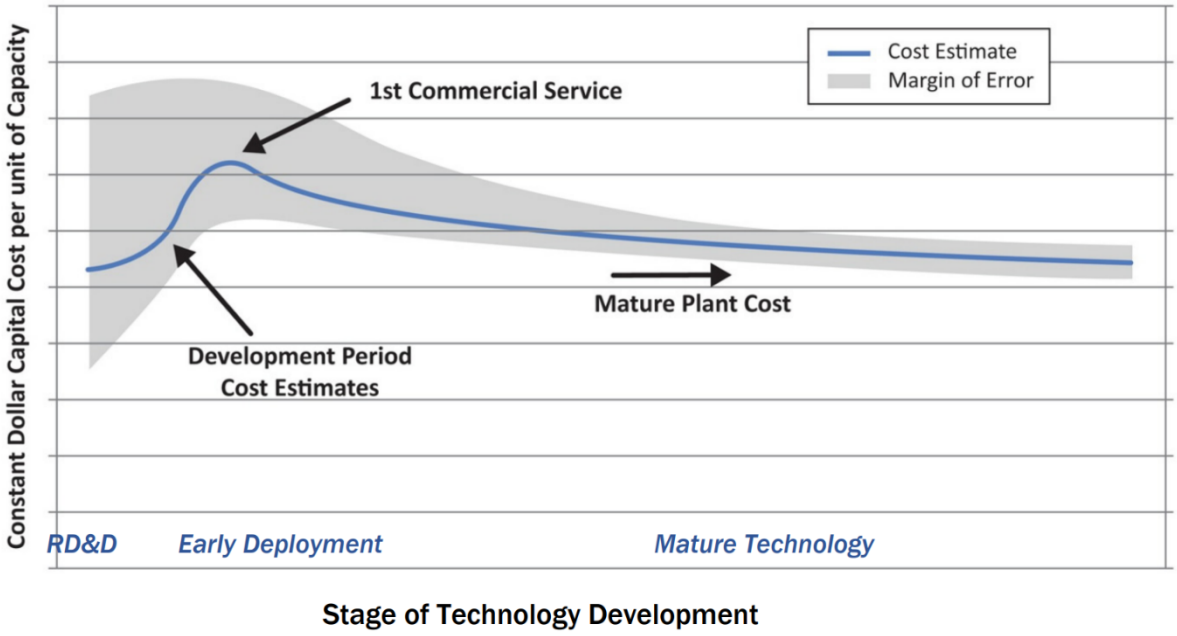


Figure 6. Stylized example of typical impacts of experience on power plant costs (blue line), including narrowing of the margin of error as technologies mature (gray shaded band). Figure comes from NETL (2013).

More broadly, attention to the dynamics of technological change—including research, development, demonstration, and deployment for emerging technologies—is important to advance an affordable and reliable clean energy transition, especially given the potential role of CCS in reaching economy-wide net-zero emissions by 2050.[16] Several simultaneous externalities may be present in energy system decisions, including negative ones associated with unpriced or underpriced emissions and positive ones associated with innovation, where benefits may lower costs and encourage broader deployment.[17] Several potential non-market factors can inhibit deployment, including technical, regulatory, and social concerns,[18] and although some IRA incentives can help offset economic and behavioral factors, these market, knowledge, and technological factors may shape adoption trajectories.

In addition, the economic incentives for clean electricity deployment and associated costs depend on the macroeconomic environment, as illustrated in Figure 7 in the cases of financing and labor costs.[19] These factors may be exacerbated by supply chain impacts and inflationary drivers, including higher interest

[16] Browning et al. (2023). Net-Zero CO_2 by 2050 Scenarios for the United States in the Energy Modeling Forum 37 Study. Energy and Climate Change, 4: 100104 (link).
EPRI (2022). *Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis*. EPRI Report 3002024882 (link).
[17] Gillingham and Sweeney (2010). Market Failure and the Structure of Externalities in "Harnessing Renewable Energy in Electric Power Systems" (link).
[18] Brown (2001). Market Failures and Barriers as a Basis for Clean Energy Policies. Energy Policy, 29(14): 1197–1207 (link).
[19] Bistline, Mehrotra, and Wolfram (2023). Economic Implications of the Climate Provisions of the Inflation Reduction Act. NBER Working Paper 31267 (link).

rates, materials and labor cost increases, tariffs, interconnection delays, and delayed infrastructure buildout (for example, transmission).[20]

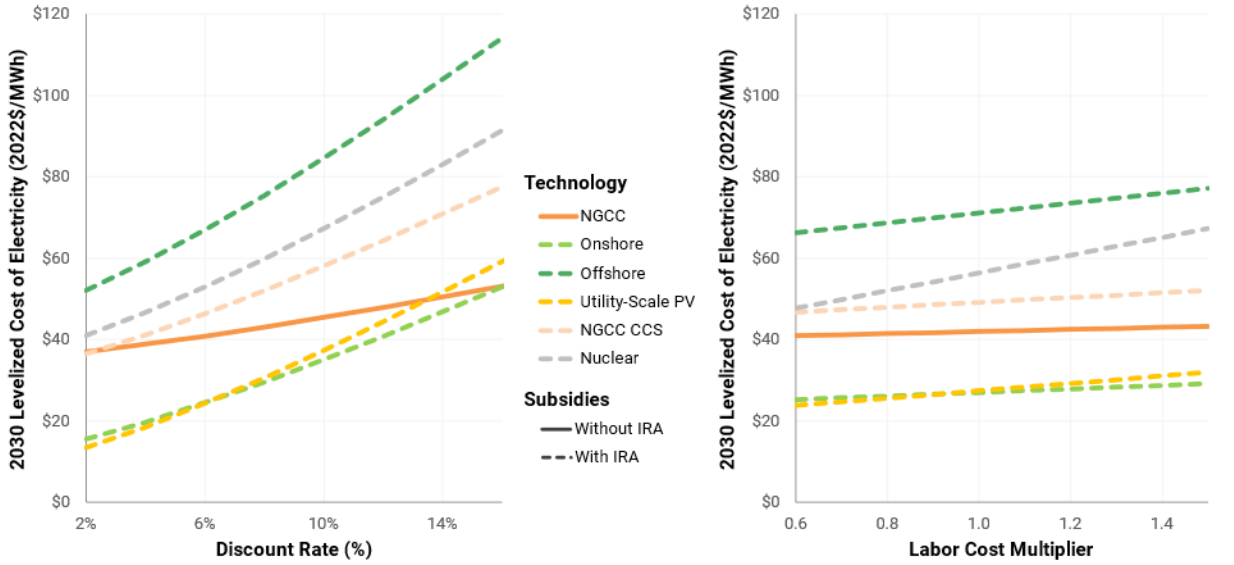


Figure 7. Levelized cost of electricity by technology in 2030 for various assumptions about discount rates (left panel) and labor costs (right panel). Costs for technologies are shown after accounting for IRA incentives, except for natural-gas combined-cycle (NGCC) capacity, which is not eligible for tax credits.[21]

Cost estimates for emerging technologies should consider potential impacts of increased demand such as equipment, materials, and labor increases and the potential of compounding effects of the proposed rules and IRA incentives.

Because of compliance timelines associated with the rules, scaling emerging technologies could rapidly put upward cost pressure on equipment, materials, and the limited pool of specialized labor, which does not appear to be incorporated into cost estimates in the rules. An example of cost escalation from increased demand for control equipment because of international and domestic pressures is capital costs for flue gas desulfurization, which increased between 2004 and 2009 (Figure 7) due to a combination of increased demand and increases in design SO_2 removal rates.[22]

These upward cost pressures from the proposed rules are in addition to changes from IRA incentives, which are expected to sharply increase demand for materials such as aluminum, cement, and steel.[23] These are compounding effects, in which the proposed rules may lead to contemporaneous demand for

[20] EPRI (2023). *Impacts of Inflationary Drivers and Updated Policies on U.S. Decarbonization and Technology Transitions*. EPRI Report 3002026229 (link).
[21] Bistline, Mehrotra, and Wolfram (2023). Economic Implications of the Climate Provisions of the Inflation Reduction Act. NBER Working Paper 31267 (link).
[22] Healy (2013). Scaling and Cost Dynamics of Pollution Control Technologies: Some Historical Examples. International Institute for Applied Systems Analysis Report IR-13-008 (link).
[23] Min et al. (2023). Effects of Renewable Energy Provisions of the Inflation Reduction Act on Technology Costs, Materials Demand, and Labor (link).

materials. This demand could amplify potential price increases because of IRA incentives that drive up demand for the same materials with similar resources deployment.

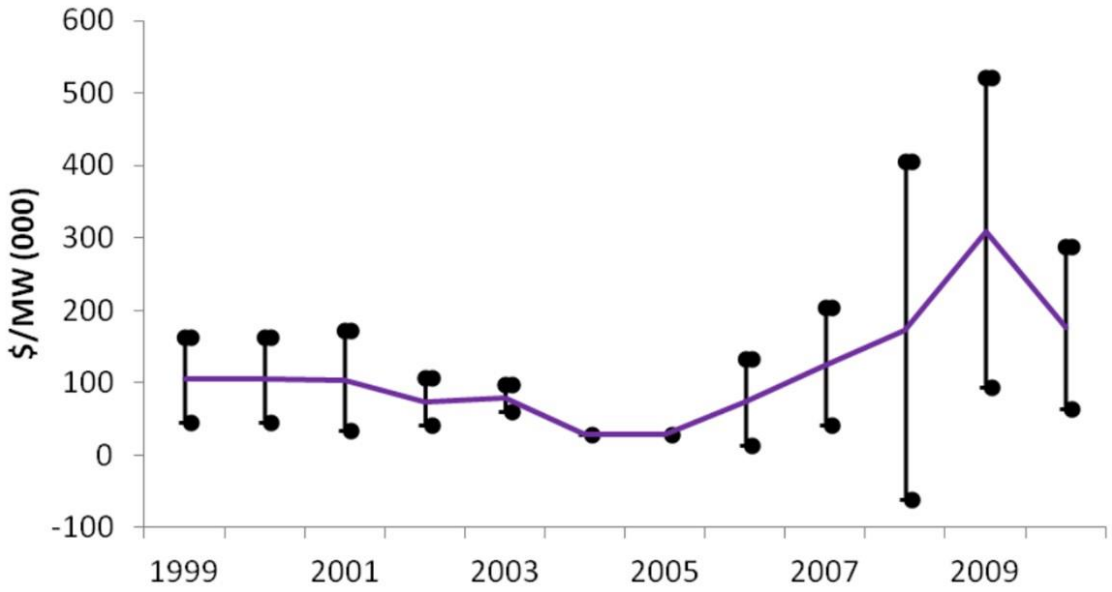


Figure 8. Historical capital costs for flue gas desulfurization. The figure comes from Healy (2013), which is based on U.S. Energy Information Administration data from 2011.

More broadly, these factors point toward the importance of considering workforce and supply chain pressures in developing technological cost projections. EPRI research has recently examined electric utility workforce development gaps implied by deep decarbonization and potential material/equipment supply chain delays, along with steps to reduce these risks.[24] These reports illustrate potential workforce shortages for skilled construction trades through 2030 (13 of 20 skilled trades exhibit resource gaps in the study) and regions in which these shortages are most pronounced (especially the Midwest). The supply chain report discusses risks and challenges associated with critical material availability; manufacturing capabilities; geopolitical, environmental, social risks, and transportation—all uncertain factors that can influence cost projections.

[24] EPRI (2022). *Electric Utility Workforce Development and Decarbonization*. EPRI Report 3002023229 (link).
EPRI (2022). *Understanding Generation and Storage Technology Supply Chain Risks and Needs to Support Electric Utility Sector Decarbonization*. EPRI Report 3002023228 (link).

Given the limited experience with emerging technologies at scale, additional metrics for comparing the costs of control technologies should be used to more completely represent costs and benefits across resource alternatives.

In justifying the chosen best system of emissions reduction (BSER), the rules consider two metrics for comparing the costs of control technologies—abatement costs (in $ per ton of CO_2 reduced) and increases in levelized costs of electricity produced (in $ per MWh increased). However, these metrics provide incomplete characterizations of the costs and benefits across resource alternatives.[25] Changes in the net present value of system costs can be a more robust metric for evaluating cost impacts of control technologies. Adding or removing a resource may lead to changes in other system investments and operations (for example, leading to greater transmission or peaking capacity needs) and may alter costs for decades to come. For example, higher-capital-cost and lower-operating-cost resources, such as variable renewables, could lead to lower fuel costs over the lifetime of an asset, which could be long-lived.

Abatement costs are often presented as point estimates in the rules, which do not accurately reflect the uncertainty about these costs because of regional variation, costs of emerging technologies, and availability of complementary technologies and resources. The limited deployment of emerging technologies to date presents uncertainty about costs and technological change as these nascent options begin to scale as well as uncertainty about the timing of deployment given unknowns about siting, permitting, construction, and project risk (see Sections 2.2 and 2.3 for discussion of carbon capture and sequestration [CCS] and hydrogen, respectively), which further contribute to cost uncertainty.

2.2. Carbon Capture and Storage

Section Summary: CCS technology is important to support economy-wide decarbonization. However, in its current state, there is uncertainty about the timing of deployment, given unknowns about siting, permitting, construction, and operations. The proposed rules use optimistic assumptions about cost, project schedule, operational flexibility, and regional viability for CCS. Importantly, CCS would require the development of infrastructure beyond what is established today. Given that CCS deployment would also depend on pipelines and storage, the technology should be considered in its entirety to fully understand the potential benefits, costs, and deployment challenges and opportunities.

CCS for power generation is in the technology validation phase of deployment and further at-scale projects are needed to reduce risk prior to broad industry implementation.

The power industry's experience with full-scale construction, deployment, and operation of CCS technology is nascent. The following table (Table 1) summarizes the current at-scale CCS experience around the world.

[25] Bistline (2021). Metrics for Assessing the Economic Impacts of Power Sector Climate and Clean Electricity Policies. Progress in Energy, 3(4): 043001 (link).

Table 1: Worldwide Large-Scale Integrated CCS Projects. There have been limited large-scale demonstrations and deployment within power generation, projects that are critical to produce industry-wide learnings for efficient and reliable technology deployment at scale.

Gas Fleet *0 demonstrations*	**Coal Fleet** *2 demonstrations*
No demonstrations to date	***Boundary Dam*** – In operation • 110-MW lignite coal post-combustion capture • Shell's integrated Cansolv process • Enhanced oil recovery (EOR) in the Weyburn-Midale oilfields, with a small portion provided to the Aquistore geologic CO_2 storage research project ***Petra Nova*** – Shut down; planned restart in 2023 • 240-MW sub-bituminous coal post-combustion capture • MHI's KM-CDR® CO_2 capture process • CO_2 was transported by pipeline ~ 130 km to the Hilcorp West Ranch oilfield and injected for EOR

When evaluating the current state of CCS technology deployment, the classic S-curve description of a technology lifecycle represents how a new technology goes through a phase of innovation (technology validation) when it is first demonstrated and embraced by early adopters, followed by one of diffusion of awareness (risk reduction), in which the industry learns and approves as technology is further demonstrated. The technology then shifts to deployment, and, finally, maturity (increasing competitiveness) as it saturates its natural market (see Figure 9). At-scale technologies today, such as the U.S. Nuclear Fleet, the Japan LNG market, and the FGD fleet, have displayed an S-curve deployment over several decades.[26] At present, CCS remains in the period of technology validation, with limited experience as compared to the potential market.

[26] EPRI (2010). *Carbon Capture and Storage At Scale.* EPRI Report 1017651 (link).

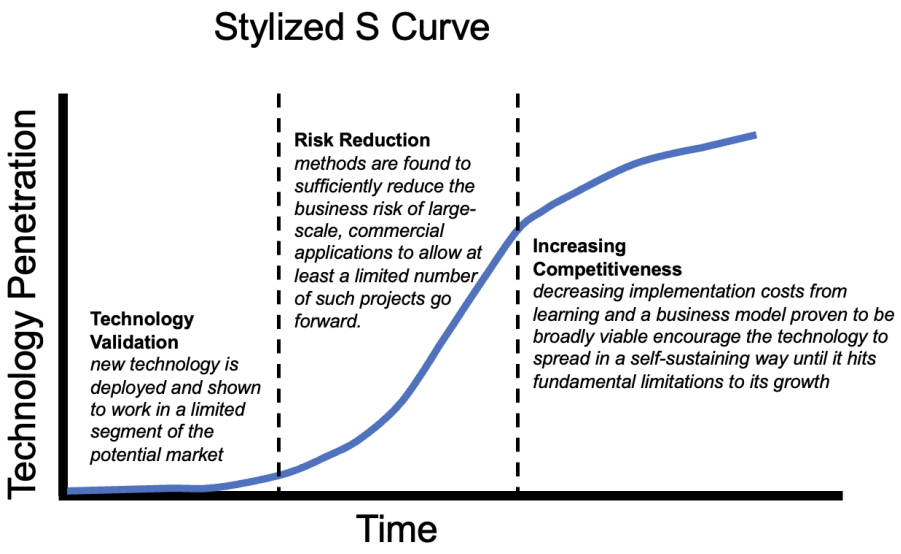


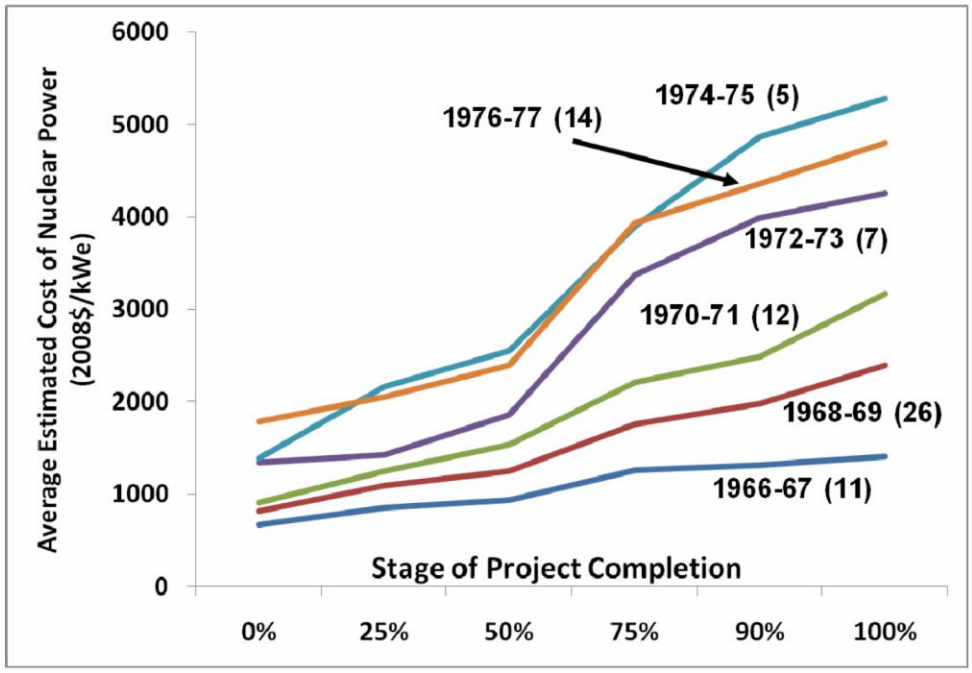
Figure 9. Stylized S Curve. Adapted from an EPRI Report.[27]

Technologies such as CCS are complex, capital-intensive, and carry uncertainty from a financial and regulatory perspective. For these technologies, demonstrations are the key enabler of risk reduction to create confidence the technology can be deployed reliably and affordably, allowing for learnings from each phase of projects and driving costs toward NOAK.

Figure 5 and Figure 8 (Section 2.1) depict the evolution of the FGD deployment an applicable learning and market effects. Figure 5 illustrates the learning effect for the FGD fleet as deployment increased over 3 decades, attributable to technological innovation (for example, new materials, better control of process chemistry) and process innovation (for example, reductions in reagent and process energy use). As the market demand grew in the early 2000s, shown in Figure 8, FGD costs increased, showing the complexity of supply chain and rapid deployment of technology.

A similar experience was seen in the U.S. nuclear power fleet transition through a rapid parallel deployment. Figure 10 shows the average estimated capital cost for U.S. nuclear power plants at different stages of construction between 1967 and 1977 (75 plants total). At the time, it was thought that economies of scale would bring costs down. However, competition in the early market led to constantly changing design, precluding the standardization that would have led to economies of scale. The rapid parallel deployment was a key driver in the cost escalation, as the industry did not have the opportunity to apply learnings from one tranche of projects to the next.

[27] EPRI (2010). *Carbon Capture and Storage At Scale*. EPRI Report 1017651 (link).



The number in parentheses is the number of projects that began construction in the indicated years. Cost estimate at 0% completion is the initial estimate, at 50% completion is the estimate at mid-stage, and at 100% completion is the final realized cost. Source: Gielecki and Hewlett (EIA Monthly Energy Review, August 1994).

Figure 10. Average Estimated Capital Cost of U.S. Nuclear Plants at Different Stages of Project Completion.

Capital-intensive technologies, like CCS, are particularly prone to these dynamics. As the power industry begins the transition from technology validation to risk reduction, the learn-by-doing phase, with intentional, documented, and shared insights, it is important to enable technology adoption that is more reliable and affordable.

Prior to full industry deployment, more full-scale CCS projects are recommended to better understand a broad range of operations challenges and implement learnings into future designs and operation.

CCS technology has been deployed at a limited scale in power generation to date. There is more to be learned and understood prior to widespread deployment in order to greatly reduce risk and minimize the costs of a second phase of projects. Some of the learnings that are still needed include actual operation capture rates, operational profile, stability, and flexibility, efficiency, land and water impacts, and community acceptance.

Proven Capture Rates

There is limited experience with proven capture rates at scale. There is no experience for carbon capture at scale on NGCC plants. There are two coal plants with experience, with varying outcomes.

The world's only operating, large-scale, full-chain CCS project at a coal-fired power plant has been operating since 2014 at SaskPower's 110-MW (net) Unit 3 at the Boundary Dam power plant in

Saskatchewan, Canada. The facility has experienced difficulties achieving the original target of 90% capture rate due to capture equipment availability, design issues, and operational challenges. The plant was sized to accommodate Unit 3's full flue gas flow, resulting in a projected CO_2 capture rate of 1.0 million tonnes per year. Realized capture in 2020, 2021, and 2022 were 729,092, 442,126, and 749,035 tonnes per year, respectively. Boundary Dam encountered and has worked through a number of issues and has shown varying availability of the CCS system, ranging from ~60% to ~93%.

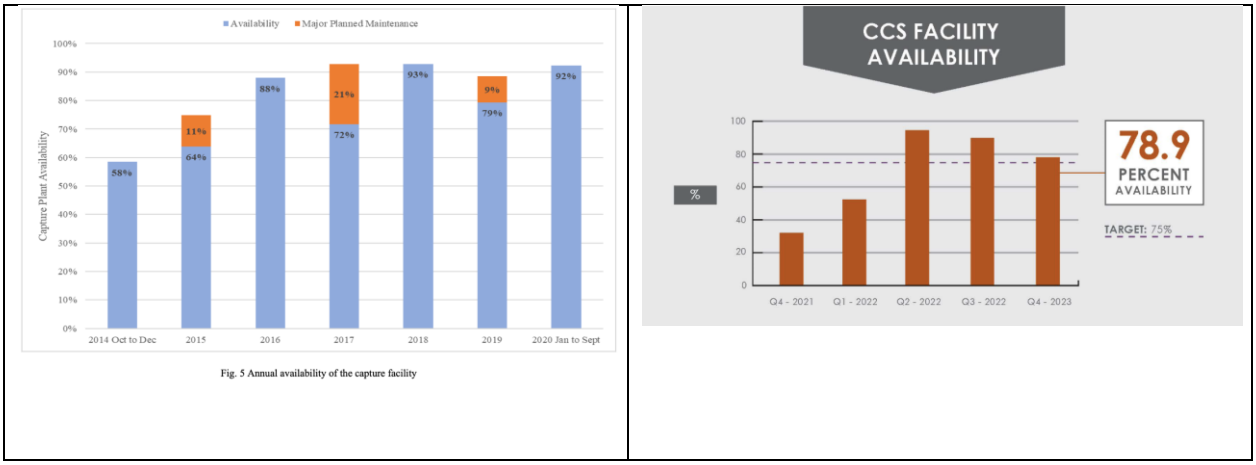


Figure 11: Boundary Dam CCS Facility Availability. The left panel shows availability Oct. 2014 through Sep. 2020.[28] The right panel shows availability 2021-2023.[29]

The Petra Nova CCS facility at NRG Energy's W.A. Parish generating station in Texas, was the world's largest power generation CCS project until it's shutdown in May 2020 due to low oil prices. The site captured a slipstream of 240 MW from the roughly 650-MW coal-fired Unit 8. During its three-year demonstration period (January 2017 through December 2019), the facility captured 92.4% of the CO_2 from the flue gas it processed.[30]

Theoretical Capture Rates. ***Less than 90%.***

To date, 90% capture rates have been the standard engineering design and approach for estimating CCS at power generation facilities. Though a capture rate reduction may be easier to realistically achieve in practice, cost and design considerations should be evaluated as part of this change, which may require alternative chemistries or process configurations. For most partial capture technologies, the total project cost should be lower. However, the specific capture cost ($/t-$CO_2$ captured) is likely to be higher unless there is a process simplification that can be implemented.

[28] https://ccsknowledge.com/pub/Publications/PAPER_GHGT15_SaskPowers_BD3_Journey_Achieving_Reliability_Mar2021.pdf

[29] https://www.saskpower.com/about-us/our-company/blog/2023/bd3-status-update-q4-2022

[30] EPRI (2022). Carbon Capture for Fossil Fuel Combustion—State of Technology. EPRI Report 3002021308 (link). The facility is scheduled to restart.

Examples of challenges include:

- **Process equipment simplification and value engineering studies.** One approach to partial capture is to make equipment modifications from a nominal 90% capture design and accept more unavailable hours and/or less-efficient operation. Although such an approach would clearly reduce capital costs ($/kW), it is unclear if it will reduce levelized costs (that is, $/ton-$CO_2$ removed or $/MWh). Value engineering studies can help determine whether the capital savings justify an availability loss. Such analyses require data (or estimates) on component failure rates and repair times. However, data are insufficient to conduct these analyses for CO_2 capture equipment.
- **Process challenge review.** Most process developers have conducted some degree of design review and testing for application on pulverized coal units, and to a lesser extent, NGCC units. However, at partial capture rates, there may be different heat and mass balances and process pinch points. Further analysis could identify process or equipment modifications that address process pinch point limitations.

Theoretical Capture Rates. ***Greater than 90%.***

Page 382 of the proposed rules offers a range of maximum capture rates. A 2022 NETL report[31] shows that the cost of CO_2 avoided is lower for the 95% removal case than for the 90% removal case. EPRI has examined the calculations and found the study to be theoretically valid. This finding may result from economies of scale, in which increasing the capture rate by some percentage increases the capital costs by a smaller percentage. EPRI and others have published research investigating the technical and economic feasibility of higher-capture-rate CCS by aqueous monoethanolamine and aqueous piperazine solvent technologies, as shown in Figure 12.

Despite the theoretical possibility to increase capture rates, the limited experience with existing power generation CCS facilities has shown that cost, operational challenges, and CCS plant availability have made achieving a consistent 90% capture rate difficult. More full-scale first-of-a-kind projects are needed to better understand a broad range of operations challenges and drive those learnings in design specifications to optimize the second phase of CCS projects.

[31] NETL (2022). Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. U.S. Department of Energy (link).
NETL (2010). Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. U.S. Department of Energy (link).

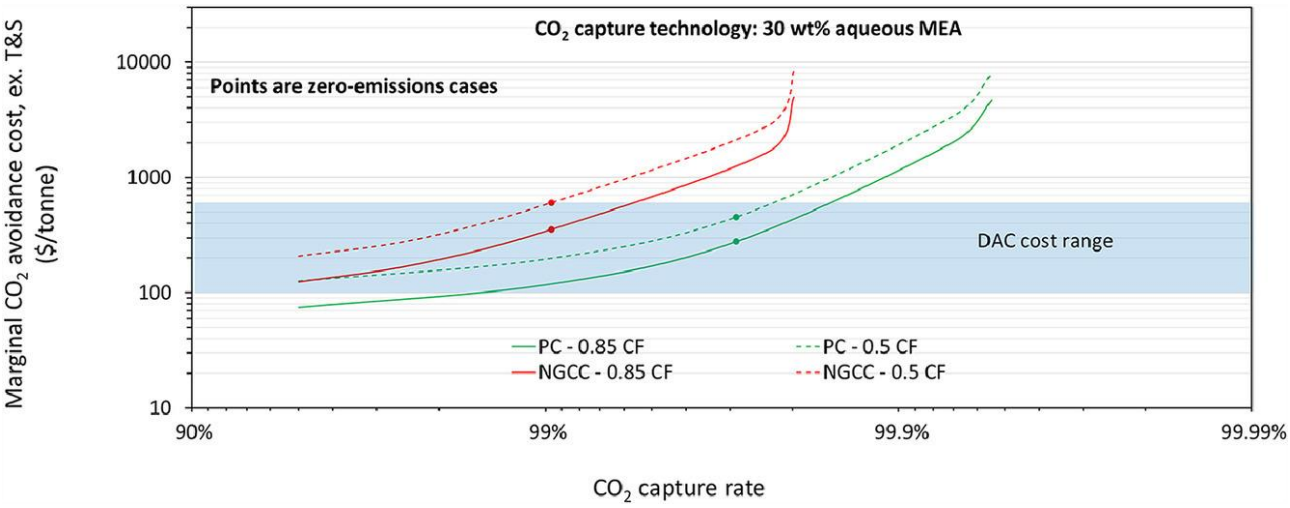


Figure 12. Theoretical marginal CO_2 avoidance cost across different CO_2 capture rates. Values are shown for pulverized coal (PC) and natural-gas combined-cycle (NGCC) power plants and exclude CO_2 transport and storage costs. Results are from Du et al. (2021).[32]

Operational Profile and Flexibility

CCS is not a single operation but instead an integrated energy system with operations of the capture unit, the CO_2 transport system, and CO_2 injection at a storage site. All three must operate in unison, in addition to operating the power plant itself. Interruptions or transients at one or more of these operations impacts the overall operation of power generation with CCS. There are very limited data of such operations at full scale for coal power plants and none for gas plants. Identifying and applying lessons learned from these types of initial operational and troubleshooting experiences can greatly increase the chances of success for CCS being widely deployed across more plants.

Per the proposed rules:

- More data and information are needed to support decision-making on startup, shutdown, and maintenance for gas with CCS. The ability and performance of a CCS unit to ramp up or down is yet to be determined, especially for gas plants (Rules, p. 180–181).
- There are R&D projects underway at technology readiness levels (TRLs) 3–5 to better understand the behavior of CCS units at lab or bench scales. However, the behavior of CCS units at full scale is dynamic and includes a broader range of confounding variables (Rules, p. 247). Moreover, lab and pilot studies are not integrated into an operating power plant and do not typically include transport and storage. The dynamics of the overall plant and CCS processes could be dependent on parameters not yet known.

Research has shown that adding CCS to operating facilities will reduce the flexibility of those units, potentially impacting steam pressures, ramping rates, and minimum load.[33] Decisions in the design process to support added flexibility are possible with additional costs. For example, at Boundary Dam,

[32] Du et al. (2021). Zero- and Negative-Emissions Fossil-Fired Power Plants using CO_2 Capture by Conventional Aqueous Amines. International Journal of Greenhouse Gas Control, 111: 103473 (link).
[33] EPRI (2016). *Flexible Operation of Current and Next-Generation Fossil Plants With and Without Carbon Capture*. EPRI Report 3002006388 (link).

one option to increase flexibility included a power plant upgrade to the turbine with enhanced steam and thermal integration and the capability to handle capture being on or off – allowing the unit to achieve full load despite the capture system operation.

Efficiency

There are several considerations and factors that go into the overall efficiency of a CCS facilities. Per the proposed rules (Rules, p. 412), for coal plants, energy for capture using amine-based carbon capture systems and subsequent compression of the captured CO_2 is approximately a factor of two of the thermodynamic limits for capture and compression. However, the auxiliary power CO_2 emissions should also be included in the CCS system (for example, some FEED studies have assumed auxiliary power is supplied by the grid).

For gas plants, technology process modeling (for example, FEED studies) suggests similar energy performance relative to thermodynamic limits might be achievable, but there are no operating gas CCS plants at scale to verify model results. The energy consumption per tonne of CO_2 captured for gas plants is expected to be higher compared to coal plants given the lower concentration of CO_2 in flue gas (for the same 90% capture efficiency). The few projects will help establish not only reproducibility and reliability of CO_2 capture technologies, but also support comparisons of process model results for different plant locations, CO_2 capture technologies, and flue gas compositions.

Land and Water Impacts

Per the proposed rules, (Rules, p. 416-417), "Footprint and water availability present potential challenges for CCS deployment". Water consumption and wastewater management should be considered when evaluating carbon capture sequestration, as CO_2 capture systems require significant amounts of water, including for cooling and absorber makeup. Estimates show water consumption for a coal CCS facility can lead to a 46% increase in overall water consumption, (56% increase for gas CCS facility). In addition, carbon storage systems may require extraction, treatment, and disposal of saline groundwater.

EPRI recommends a phased approach that includes a diverse set of full-scale projects to reduce the uncertainty associated with broad deployment of non-scaled technologies, drive broad industry learning about site operation and impacts, and support achievement of n^{th}-of-a-kind costs.

A phased approach to CCS deployment can enable the power sector to learn more about performance, cost, flexibility, and operation, while reducing risk and improving the reliability and affordability of industry-wide technology adoption. EPRI suggests 10–20 full-scale CCS projects, coupled with CO_2 transportation and storage, that enable shared learnings as each project progresses. This can provide the necessary "learning-by-doing" experience for technology deployment, greatly reducing risk and driving cost reductions for a second phase of projects. Learning from the next phase of coal projects and the first phase of natural gas projects can help close gaps identified within the proposed rules and accelerate technology deployment toward NOAK project cost.

The phased approach of CCS deployments should consider size, capacity factor, fuels, sequestration readiness, and other criteria that are important to building a diverse operational experience knowledge basis necessary to achieve performance requirements at full scale. This set of projects should address

known uncertainties around broad deployment across coal and gas assets, as well as CO_2 transport, storage, and other uncertainties.

Table 2: Further Projects Needed for Industry-Wide CCS Deployment.

<table>
<tr><td colspan="2">A phased approach to CCS deployment can enable the power sector to learn more about performance, cost, flexibility, and operation, while reducing risk and improving the reliability and affordability of industry-wide technology adoption. These projects should consider size, capacity factor, fuels, sequestration readiness, and other criteria to build a diverse operational experience knowledge basis necessary to achieve performance requirements at full scale.</td></tr>
<tr><td colspan="2">Cross-Cutting Topics
10 to 20 projects total</td></tr>
<tr><td colspan="2">• Capture, compress, and transport the CO_2 by pipeline to proposed injection sites located onshore or offshore for geologic storage
• Geologic storage and monitoring at CO_2 storage reservoir sites
• Wet and dry cooling systems
• Variety of operational profiles</td></tr>
<tr><td>Gas Fleet</td><td>Coal Fleet</td></tr>
<tr><td>• Retrofit of post combustion capture on NGCC
• New build of NGCC with CCS
• New build of advanced cycle with integrated CCS</td><td>• Variety of fuels, including lignite, bituminous, sub-bituminous, and potentially anthracite
• Retrofits of post-combustion capture on existing coal units
• Larger projects (>300 MW) on existing pulverized coal units are needed</td></tr>
</table>

Each CCS project should provide insights that help streamline the next phase of projects, standardize critical elements, and inform the supply chain and design specifications and standards.

Insights from each CCS project can accelerate cost reductions, improve operational performance, support supply chain ramp up and reliability improvements, through "learning-by-doing."

- **nth-of-a-kind cost:** As described in Section 2.1, historical experience with highly complex systems has shown that, after first-of-a-kind projects are launched, the next phases or projects can experience costs increases. A phased approach to broad CCS deployment can better address complexity and uncertainty to support and accelerate the holistic learnings needed to drive progress toward NOAK costs while maintaining energy system reliability and affordability.
- **Emission rates and solvent performance:** There are limited available data on emissions from carbon capture units and solvent performance at full scale due to the proprietary nature of each process developer's chemistry and process details. Though EPRI has performed extensive literature reviews[34] and is currently conducting modeling studies of these emissions, the effort is limited to those chemistries that are publicly reported and have sufficient transparency. Most capture process developers have not publicly published their emissions data or cost and process

[34] EPRI (2022). *CO_2 Impurities Literature Review—2022 Update: Contaminants in Post-Combustion CO_2 Capture*. EPRI Report 3002024319 (link).

detail data. Such emissions measurements and public reporting should be part of the initial phase of CCS deployments.

- **Site operational and reliability data and experience.** There is a significant amount of learnings that can come from the sharing of relevant information to ensure each future project learns from the others. A sampling of this information is provided in Table 3 below.

Table 3. Site Operation and Reliability Data and Experience for Risk Reduction.

Site Operational and Reliability Data and Experience for Risk Reduction	
Power Plant Data and Experience	• Design and measured heat and mass balance with full characterization of all flow streams leading to and exiting CCS and environmental control equipment • Design and measured performance impacts because of CCS including energy penalty (thermal and MW) and relative change in cost of electricity • Design and measured performance of all environmental control equipment including emission outputs and % reductions • Design process flow diagrams • Environmental control equipment (type, characteristics, and so on) • Issues affecting permitting of the plant • Modifications made to steam circuit including turbine based on site visits, discussions with experts, and web-casts • Onsite details on construction with welding procedures • Process control and instrumentation details (systems, operation, and so on) • Workforce training material and community and stakeholder engagement
Capture System Data and Experience	• Any flue gas pre-treatment required • Design approaches evaluated and how final selection made based on site visits, discussions with experts, and web-casts • Design and measured capture efficiency and its dependence on process conditions • Design and measured environmental performance with sources of discharge and disposal of heat stable salts • Design and actual fixed and variable O&M costs including solvent make up rates • Design and actual heat and mass balance with full characterization of all flow streams leading to and exiting capture system • Design and actual heat of regeneration, cooling requirements, and auxiliary power • Design process flow diagrams and list of equipment • Process control and instrumentation • Sources of heat used by capture plant • Operational characteristics and constraints • Operational experience – reliability, start-up/shut-down procedures, level of automated operation, response to transients, maintenance requirements, and so on • Workforce training material and community and stakeholder engagement

Site Operational and Reliability Data and Experience for Risk Reduction	
Storage System Date and Experience	• Assessment of existing subsurface data • Detailed description with drawings of CO_2 transportation and storage site • Permits and lessons learned from both the drilling and permit processes • Pipeline routing and products specifications • Transmission design • Annual fluid monitoring of injection zone • Annual cross-well seismic monitoring reports/data • Changes to the modeled/projected CO_2 footprint • Continuous atmospheric CO_2 monitoring near all wells • Continuous micro-seismic monitoring in monitoring well • Descriptions of any events that trigger a shutdown of injection wells • Mechanical integrity tests following annual monitoring events • Monthly summaries (average, maximum, and minimum) of CO_2 injection pressure, temperature, and flow rate; injection well annulus pressure; and bottom-hole temperature and pressure in all wells • Monthly volumes of CO_2 injected and cumulatives so far • Periodic vadose-zone soil gas monitoring for detection of CO_2 leakage • Pressure fall-off tests performed on the injection wells • Quarterly analysis of CO_2 stream chemical composition, corrosion monitoring of well and pipeline materials, groundwater monitoring of the underground source of drinking water • Workforce training material and community and stakeholder engagement

Cost estimates for CCS in the proposed rules should clearly reflect current cost reduction trends and anticipated incentive impacts.

Greater transparency could increase confidence in cost estimates. The NETL Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity report acknowledges CO_2 capture is an emerging technology and the costs presented are reflective of the costs for representative applications. NETL also says that it anticipates that "initial deployments of these plants may incur costs higher than those reflected within this report" which is consistent with EPRI's evaluations. The report goes on to say, "Continuing research, development, and demonstration (RD&D) is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated."[35]

It is important to clearly state the basis of cost estimates provided in the NETL baseline report. This document uses a vendor quote on performance and cost, which does not reveal the basis of these numbers. Prior baseline reports also do not reveal details; therefore, it is not pracital to make comparisons or projections for cost reductions using these reports. NETL includes an expansive portfolio of mid- to late-stage projects in which performance and cost are provided with varying levels of detail The hypothetical cost estimates are built upon generic design parameters that cannot be used to simulate or predict actual

[35] NETL (2022). Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. U.S. Department of Energy (link).
NETL (2010). Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. U.S. Department of Energy (link).

plant sites. These cost estimates are meant to reflect a wide range of uncertainty and could therefore underrepresent real costs when technology readiness, site factors, and market conditions are incorporated.

The DOE has funded 14 FEED studies (five for coal and nine for gas) under Funding Opportunity Announcement (FOA) 2058 and FOA 2525.[36] Of these, six reports have been published on retrofits – three for coal and three for gas.[37] FEED studies provide insight into site-specific designs and market conditions that impact costs. These studies precede the final investment decision and engineering design and are more accurate than hypothetical studies, such as the NETL baseline report, in representing costs. Although comparing FEED studies from different sites is not practical, one example demonstrates how site-specific factors can represent a large portion of costs not included in hypothetical cost estimates.[38] The results of the FEED studies could be used to update cost and performance methodologies and provide better insights and accuracy on predicted deployment costs. It is important to note, however, that several of the DOE-funded FEED studies do not disclose sufficient performance and cost details in the public reports. This is driven largely by the proprietary nature of the CO_2 capture processes, which is similar to the approach taken in the NETL baseline study. Therefore, some FEED studies provide limited information on how one CO_2 capture system might perform at another site.

[36] U.S. DOE (2019). Front-end engineering design studies for carbon capture systems on coal and natural gas power plants. DE-FOA-0002058 (link).
U.S. DOE (2022). Carbon Capture R&D for Natural Gas and Industrial Point Sources, and Front-End Engineering Design Studies for Carbon Capture Systems at Industrial Facilities and Natural Gas Plants. DE-FOA-0002515 (link).
[37] OBrien, et al (2022). Full-scale FEED Study for Retrofitting the Prairie State Generating Station with an 816 MWe Capture Plant using Mitsubishi Heavy Industries Post-Combustion CO2 Capture Technology. Univ. of Illinois at Urbana-Champaign, IL (link).
Crane, C (2022). Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station. Enchant Energy, L.L.C. (link).
Merkel, et al (2022). Commercial-Scale Front-End Engineering Design (Feed) Study for MTR's Membrane CO2 Capture Process. Membrane Technology and Research, Inc. (link).
Lunsford, et al (2022). Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant. Southern Company Services, Inc. (link).
Bhown, A (2022). Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant. EPRI (link).
Elliot, W (2021). Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant (2x2x1 Duct-Fired 758-MWe Facility with F Class Turbines). Bechtel National, Inc. (link).
[38] Martorell J, Rochelle G, Baldea M, Elliott W, Bauer C. Comparison of Detailed Capital Expense Estimates for Two NGCC Retrofits with Capture by Amine Scrubbing. ChemRxiv. Cambridge: Cambridge Open Engage; 2022; This content is a preprint and has not been peer-reviewed.

Lack of details and limited CCS deployment likely lead to incomplete cost-reduction assumptions. More projects are recommended to validate and drive future cost reductions. While the NETL baseline reports suggest CCS costs are reducing over time, recently completed FEED studies for natural gas CCS retrofits demonstrate how CO_2 capture costs can vary based on many different design assumptions (such as capacity factor, capture rate, site specific requirements, interest rates, and other market conditions). For example, two of these publicly available FEED studies resulted in higher costs than those estimated in the NETL baseline study (see Figure 13).[39] Relevant factors that vary costs are not reflected in the analysis for the proposed ruling and the docket does not provide a basis for the claim that cost reductions for CCS absent IRA tax credits are achievable. Increasing the accuracy of CCS cost estimates requires commissioned projects at scale.

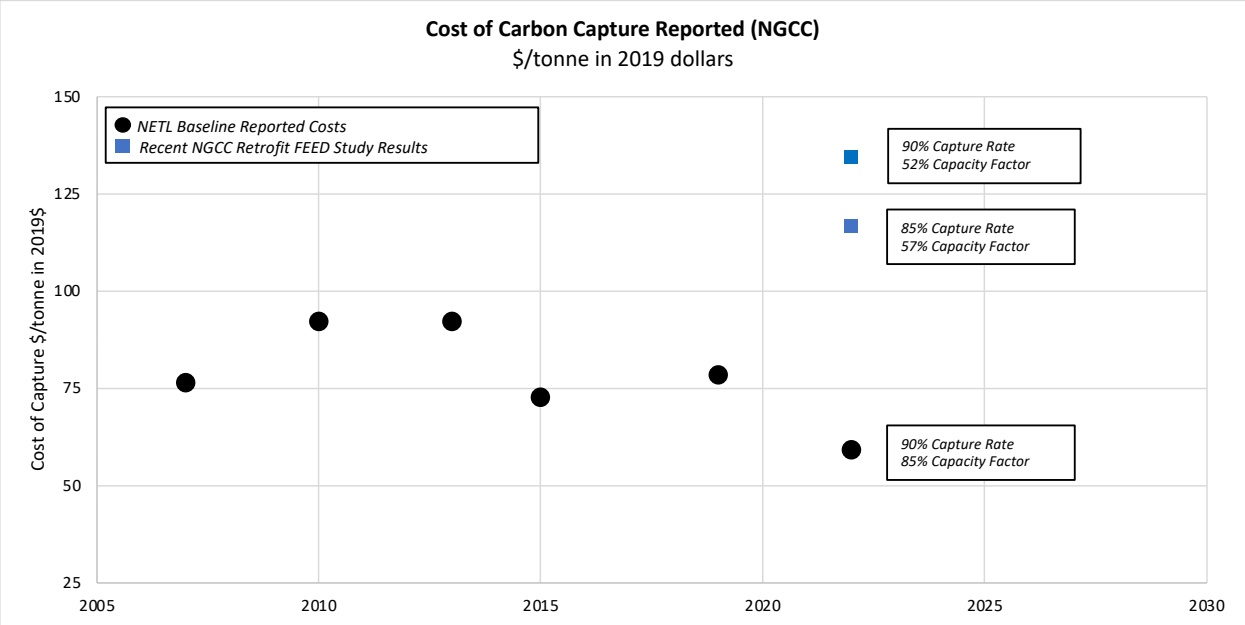


Figure 13. Cost of carbon capture reported for NGCC cost trends based on data from NETL's Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity reports and recently published DOE FEED studies on NGCC retrofits. The NETL baseline report and recent FEED studies use different assumptions for capacity factor, capture rate, financing costs, and other factors. This comparison demonstrates the potential for understating costs and variability across projects.[40]

Evaluating the cost of carbon capture with and without financial incentives presents a more representative picture of actual costs and benefits. To be eligible for 45Q credits for captured CO_2 in IRA, facilities must commence construction by the end of 2032. As proposed, CCS-based standards for new and existing gas-fired EGUs under the proposed rules take effect in 2035. If there are delays in

[39] Elliot, W (2021). Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant (2x2x1 Duct-Fired 758-MWe Facility with F Class Turbines). Bechtel National, Inc. (link).
Rochelle, G (2022). Piperazine Advanced Stripper (PZAS™) Front End Engineering Design (FEED). The University of Texas at Austin. (link).
[40] Ibid

starting CCS projects or developing the associated CO_2 transport and storage infrastructure, it may be challenging or impossible for firms to take advantage of IRA incentives in time to support 111 compliance deadlines. Meeting targets without CCS or associated tax credits could increase emissions and/or costs of achieving standards of performance required by the proposed rules. Although it is possible that endogenous technical change lowers CCS costs over time, there is considerable uncertainty about future costs. In addition, there is a risk that CCS-equipped capacity could retire after 45Q credits expire unless another policy (for example, production-based credits) supports continued operation after the 12-year tax credit period.[41]

The implementation timelines for CCS deployment should be revised to 1) accurately reflect documented experiences and expectations; 2) account for necessary individual project execution uncertainty and inexperience of designing and operating CO_2 capture, transport, and sequestration projects; and 3) reflect lack of knowledge and experience in completing CCS project activities across industry.

- **Documented experiences and expectations:** The proposed project schedule for implementation of BSERs on steam EGUs would require significant scaling and faster deployment than the limited experience so far has shown and does not fully reflect uncertainty and schedule impacts associated with planning, permitting, sequestration, and construction.

  On page 499 of the proposed rules and page 35 of the CCS Technical Support Document (TSD),[42] the project schedule for implementation of CCS on targeted existing steam EGUs assumes that retrofits can be completed within five years. Given the varying amount of uncertainty from project to project, a distribution of timelines is likely needed for the targeted EGUs. Industry and expert consensus for a single CCS project deployment from feasibility through construction is about 7–10 years, 1.5–2 times longer than the duration assumed in the project schedule. The Global CCS Institute presents a simplified project timeline of 9.5 years.[43] The U.S. Department of Energy's Office of Clean Energy Demonstrations presents a nominal project timeline for full-scale CCS demonstrations of 6–10.5 years.[44] This timeline assumes that feasibility and FEED studies—which typically take a minimum of 1.5–2 years—have been completed, making the DOE timeline closer to 7.5–12.5 years. FEED studies have been conducted on a limited number of EGUs, and most EGUs have not conducted initial feasibility studies. Therefore, the five-year implementation timeline does not present a likely time frame to achieve broad CCS deployment.

  The CCS transportation and storage five-year schedule presented on page 37 of the CCS TSD assumes that the site characterization and permitting step can be completed in two years. This is less than half the time the permitting process for the two class VI wells (about five to six years) from initial application to drilling the well and final issuance of an Authorization to Inject.[45]

[41] Bistline et al. (2023). *Impacts of Inflationary Drivers and Updated Policies on U.S. Decarbonization and Technology Transitions*. EPRI Report 3002026229 (link).
[42] U.S. Environmental Protection Agency (2023). Greenhouse Gas Mitigation Measures: Carbon Capture and Storage for Combustion Turbines Technical Support Document (link).
[43] Global CCS Institute (2022). Global Status of CCS 2022 (link).
[44] U.S. Department of Energy (2023). Funding Notice: Carbon Capture Demonstration Projects Program, FOA Number DE-FOA-0002962 (link).
[45] EPA (2023). Class VI Wells Permitted by EPA. U.S. Environmental Protection Agency. Retrieved June 16, 2023 (link).

- **Individual project execution uncertainty and inexperience:** An effective due diligence process may prove that initial assumptions are incorrect and lead to project termination. For example, the Queensland and Australian Governments, as well as the Australian Coal Association, spent 73% of prefeasibility study costs ($100 million Australian) on the underground storage appraisal for the ZeroGen project in Queensland, Australia.[46] This due diligence process included extensive exploratory drilling, which proved that the subsurface resource was not suitable. As such, the project did not move forward. This case study illustrates the impact that site characterization can have on commercial viability, which could complicate deployment.

- **Lack of knowledge and inexperience in completing CCS project activities across industry:** It is important to account for the impacts of other factors, such as increased CCS demand, supply chain ramp-up, CO_2 well characterization, and permitting and regulatory approvals. EPRI research has found that these uncertainties can lead to extended project timelines and potential project cancellations.

Regional-, site-, and unit-level costs and feasibility should be considered for individual CCS project deployment.

As noted previously, CCS costs and performance include more than CO_2 capture. Other factors must be included, such as transport systems, availability of CO_2 storage, water, public acceptance, and power plant-specific design considerations. This suggests that, although CCS may be suitable for one site using proposed criteria, it may not be suitable for another site that falls within the proposed criteria. At minimum, feasibility for capture, storge, public acceptance, regulatory, legal, and financial studies need to be conducted before any given site can be considered for potential deployment. If these studies appear promising, additional work would be needed for FEEDs, site characterization, regulatory filings, financial investments, and legal aspects to determine CCS viability. The following criteria should be considered:

- **The primary measure of CCS costs in the proposed rules, $/t$CO_2$, is inadequate as a stand-alone metric to compare costs across CCS projects for EGUs. EPRI recommends considering t-CO_2/MWh, in addition to $/t-$CO_2$, to account for varying efficiency of EGUs.** EGU efficiency impacts the overall costs of CO_2 capture. Less-efficient units emit more CO_2, creating a lower cost-per-ton basis for an equally sized unit with greater efficiency. To adequately compare costs across projects, a more accurate approach involves first specifying the specific CO_2 emissions rate (t-CO_2/MWh), with the cost of CCS being calculated to achieve this rate. However, because CO_2 credits and tax incentives are structured in $/t-$CO_2$ terms instead of t-CO_2/MWh, it is likely that commercial deployment may be more financially sound for less-efficient plants as opposed to more efficient units.

MIT (n.d.). "Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project." MIT Carbon Capture and Sequestration Technologies Program. Retrieved June 16, 2023 (link).
Lau, et al. (2022). "Carbon Capture, Utilization and Storage Class VI Wells and US State Primacy." Mayer Brown. Retrieved June 16, 2023 (link).
National Petroleum Council (2021). Chapter Three – Policy, Regulatory, and Legal Enablers. In "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage" (link).
[46] Garnett. Greig, and Oettinger (2014). ZeroGen IGCC with CCS: A Case Study. The University of Queensland (link).

- **Distance to CO_2 sequestration is not an adequate measure of resource viability or commercial readiness. EPRI recommends using an established framework to classify CO_2 storage readiness, such as the Society of Petroleum Engineers Storage Resource Management System classification framework.** The geographic availability analysis (Rules, p. 220) presents that geologic sequestration is feasible and CO_2 storage opportunities are widespread if potential storage resources readily accessible by a pipeline exist within 100 km (62 mi) of most power stations. However, many other factors must be considered when determining the feasibility of a commercial-scale CO_2 sequestration site.

Significant variability exists between potential geological sequestration sites, based on capacity and injectivity, and are mainly affected by formation porosity, permeability, pressure, and thickness. These prosperities can have a significant impact on CO_2 storage costs and overall CCS project viability. In Figure 14, three regional locations are shows, representing the Mount Simon Formation, Knox Formation, and Basal Sandstone Formation. Costs differences can vary more than four-fold because of location.

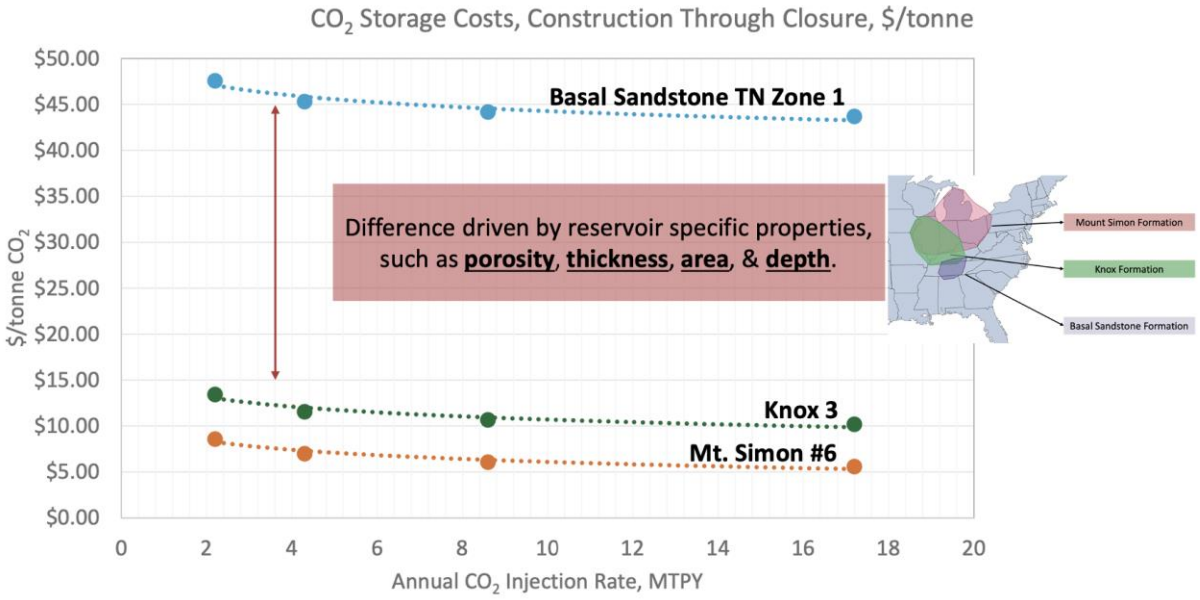


Figure 14. CO_2 Storage Costs.[47]

Factors beyond costs need to be considered. Storage reservoirs within 100 km of a power station may be excluded from commercial consideration because of logistical, technical, financial, social, environmental, and/or other constraints. Especially important is aggregating large land holdings that will encompass the very large areas occupied by the CO_2 in the subsurface, plus an adequate buffer. Project developers must negotiate with property owners to obtain the rights to the pore space, mineral, surface, and possibly water rights within the project footprint. Without unitization rules for CO_2 storage, site development may not be practical or feasible in many areas of the country.

[47] EPRI (2021). *Carbon Capture, Transportation, and Storage Cost Study.* EPRI Report 3002022302 (link).

The Society of Petroleum Engineers published the Storage Resource Management System (SRMS) in 2017,[48] which is intended to provide consistent definitions and guidelines for determining the viability of CO_2 storage resources and maturation of CO_2 storage projects. This document is not referenced in the proposed rules. In this document, most of the resource assessments performed by DOE and USGS so far would fall into the SRMS classification framework as being either an "undiscovered" or "discovered sub-commercial" storage resource. A handful of reservoirs and/or sequestration sites have been assessed so far that could truly be classified as "discovered commercial" proven, probable, or possible.

Water consumption and wastewater management should be considered when evaluating carbon capture sequestration as BSER. CO_2 capture systems require significant amounts of water, including for cooling and absorber makeup.

The addition of CO_2 capture processes requires additional water for each process step.[49] Figure 15 depicts a process flow diagram of a typical post-combustion capture system from the flue gas produced by coal- or natural gas-fired units. Water is required to pretreat and cool the incoming flue gas, cool the exothermic absorption reaction, remove volatiles from the flue gas, and cool the CO_2 stream. For transport, the CO_2 compression stages require intercooling and aftercooling. [50]

Although wastewater is produced from the direct contact cooler, it may be reused. In a typical coal or gas application, treatment will likely be required.[51] If it cannot be reused, it will need to be treated and discharged. In addition, for each of the cooling water stages, wet or hybrid (wet/dry) cooling applications produce a cooling water blowdown stream that requires disposal.[52]

[48] Society of Petroleum Engineers (2022). CO_2 Storage Resources Management System (link).
[49] EPRI (2022). *Comparing Methods of Supplying Thermal Energy for Regenerating Carbon Capture Solvents.* EPRI report: 3002024314 (link).

[50] EPRI (2023). *Water Considerations and Needs for Carbon Capture.* EPRI report: 3002027352 (link).
[51] T. Schmitt, S. Leptinsky, M. Turner, A. Zoelle, C. White, S. Hughes, S. Homsy, M. Woods, H. Hoffman, T. Schultz, and R. E. James. *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity.* National Energy Technology Laboratory, 2022. https://doi.org/10.2172/1893822.
[52] EPRI (2023). *Water Considerations for the Energy Transformation.* EPRI report: 3002027353 (link).

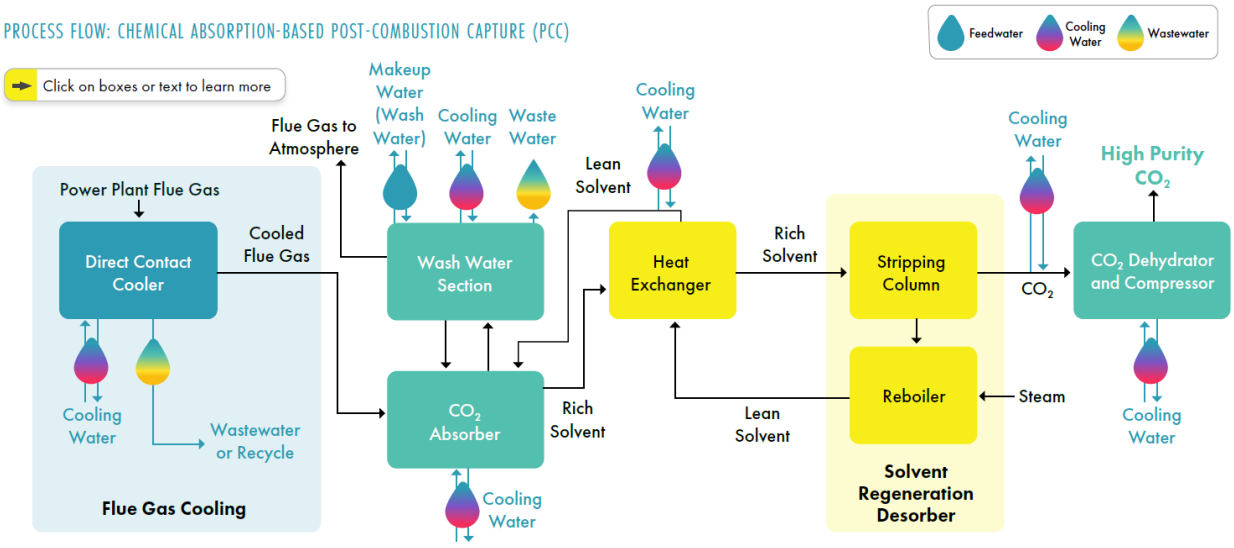


Figure 15. Chemical absorption-based post-carbon capture system process flow diagram.[53]

Table 4 provides estimated water usage rates for supercritical pulverized coal (PC) and natural gas combined-cycle (NGCC) units with and without a 90% CO_2 capture system, according to an NETL study. Total water demand (withdrawal) is estimated to increase by 64% and 85% for a PC and NGCC unit equipped with CO_2 capture, respectively. The increased water withdrawal and consumption rates present potential challenges to local surface water bodies and may require additional permitting requirements for facilities. The increased water discharge rates (132% and 187% for PC and NGCC, respectively) may require additional wastewater treatment systems.

[53] EPRI (2023). *Water Considerations and Needs for Carbon Capture.* EPRI report: 3002027352 (link).

Table 4. Estimated water usage rates for a pulverized coal supercritical unit and a natural gas combined cycle unit.[54]

Estimated water usage rates for a pulverized coal supercritical unit			
	Withdrawal (gal/MWh)	Discharge (gal/MWh)	Consumption (gal/MWh)
Without CO_2 Capture System	559	115	444
With 90% CO_2 Capture System	915	267	648
% Increase with CO_2 Capture	**64%**	**132%**	**46%**
Estimated water usage rates for a natural gas combined-cycle unit			
	Withdrawal (gal/MWh)	Discharge (gal/MWh)	Consumption (gal/MWh)
Without CO_2 Capture System	240	54	185
With 90% CO_2 Capture System	443	155	288
% Increase with CO_2 Capture	**85%**	**187%**	**56%**

As for sequestration, carbon storage systems may require the extraction, treatment, and disposal of saline groundwater.

Large-scale storage of CO_2 in saline aquifers may be necessary for the successful deployment of carbon capture and storage (CCS) technology on fossil-fired electric power stations. At some CO_2 storage sites, pressure management of these reservoirs may require extraction and treatment of saline groundwater. Treatment system requirements and costs are affected by the water quality and flow rate of the extracted brine.[55] Site-specific conditions such as pressure management techniques and aquifer storage capacity will impact the time at which the saline brine may (or may not) require extraction and the resulting flow rate of the extracted brine (Figure 16).[56]

[54] T. Schmitt, S. Leptinsky, M. Turner, A. Zoelle, C. White, S. Hughes, S. Homsy, M. Woods, H. Hoffman, T. Schultz, and R. E. James. *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity.* National Energy Technology Laboratory, 2022. https://doi.org/10.2172/1893822.
[55] EPRI (2023). CCS Brine Treatment Technoeconomic Analysis (TEA) Tool (link).
[56] EPRI (2023). *Water Considerations for the Energy Transformation.* EPRI report: 3002027353 (link).

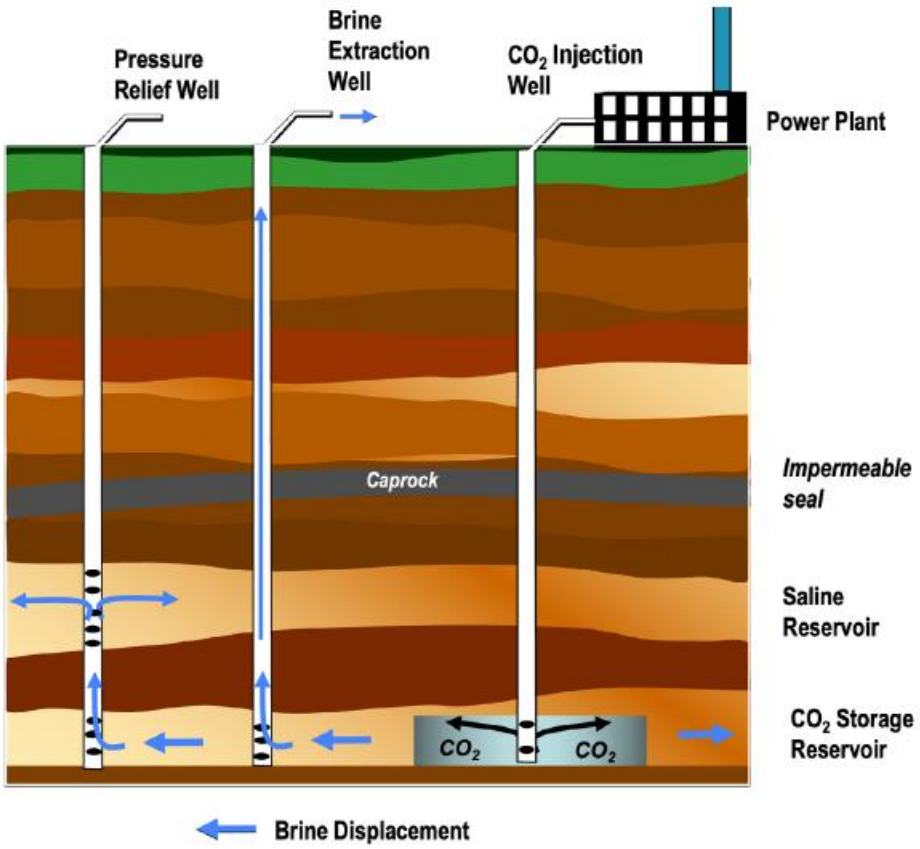


Figure 16. Hypothetical CO_2 storage project with both passive pressure relief and active extraction wells.[57]

Extracted brine requires treatment because it cannot be released to surface waters to impact groundwater or waterways. When the treated water is purified to less than approximately 500 mg/L TDS, it can be reused at the power plant or for other purposes. The treatment facility takes flow from the extraction well and treats it to remove dissolved salts and suspended solids, yielding usable desalinated water. The remainder, a concentrated brine, could then be reinjected into a saline reservoir separate from the CO_2 storage (Figure 17) if permitting allows. Reinjected brine, about a tenth of the extracted volume, may be as concentrated as 100,000 mg/L TDS or higher. Alternative disposal may include reduction of brine to solid waste material, for managed landfill disposal, or development of methods to encapsulate brine without removing all moisture.[58]

[57] EPRI (2023). CCS Brine Treatment Technoeconomic Analysis (TEA) Tool (link).
[58] Trautz, Robert C. "Phase II Field Demonstration at Plant Smith Generating Station." Electric Power Research Institute. U.S. Department of Energy DE-FE0026140. April 5, 2016. https://netl.doe.gov/sites/default/files/netl-file/1400-20190827-200PFE0026140-EPRI-final.pdf.

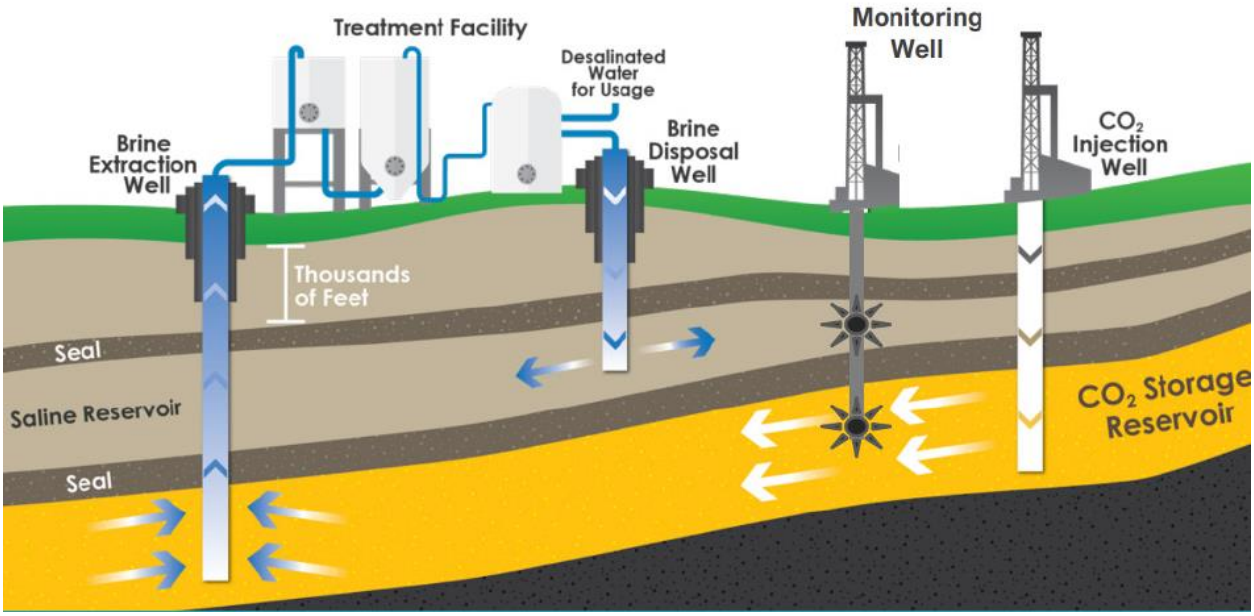


Figure 17. Depiction of brine extraction treatment facility.[59]

The complexity of the extracted brine treatment system will vary based on the influent water quality, effluent re-use requirements, and target treatment system recovery rate to minimize concentrate volume. The treatment system will likely include a combination of the following unit operations: physical/chemical softening, multimedia filtration, ion exchange, ultrafiltration, reverse osmosis, and/or thermal evaporator/crystallizer.[60] These add additional cost to a full CCS system.

[59] Ibid.
[60] Swisher, J. A., Trautz, R., Preece, J., Rhudy R., Breckinridge, R., Bhown, A., and DiFilippo, M. "Techno-economic analysis of extraction, treatment, and distribution of brines as a part of pressure management operations for CO2 storage in saline aquifers." Carbon Management Technology Conference (CMTC 2017). Houston, TX. July 19, 2017. https://www.aiche.org/system/files/aiche-proceedings/439541/papers/503814/P503814.pdf.

2.3. Hydrogen

Section Summary: Although hydrogen is an emerging resource and a growing focus of pilots and demonstrations, the technology—and its key supporting components—have not been demonstrated at the scale envisioned by the rules. Today, there is not a market for or source of scaled low-emitting hydrogen available. Building out this energy economy at this scale—nearly 770 trillion Btu of demand in 2035, representing more than two-thirds of today's hydrogen production—would require new infrastructure, markets, policies, and technologies. Assumptions in the rules do not reflect the uncertainty surrounding hydrogen costs, development, and operation.

The rules should account for the lack of current lack of low-emissions hydrogen and the early stage of technology availability to meet the proposed market demand.

Today, the U.S. produces approximately 10 MMT of hydrogen annually for refining, ammonia and methanol production, metals production, and other processes. Nearly all this hydrogen is produced from fossil fuel without CO_2 capture and sequestration,[61] and none of the hydrogen qualifies as a low-emission fuel suitable for power generation under the proposed rules. Although other technologies such as methane pyrolysis and electrolysis are expanding to larger commercial scale, there are insufficient production sources available today to support economy-wide scale.

The technologies required to produce low-emission hydrogen, as defined by the rules, are not currently deployed at a scale to serve the potential market. Low-carbon hydrogen is not currently available as an industry-wide fuel for power generation.

The only industry-scale hydrogen production process available today is steam methane reforming, without CO_2 capture and sequestration, and nearly all the market is located in the Gulf Coast.[62] NETL's cost estimate for hydrogen production from new-build steam methane reformers without CO_2 capture and sequestration is $1.06 per kilogram (kg) in 2018 dollars. Although not demonstrated commercially, NETL estimates that achieving a greenhouse gas emissions rate of 0.38 kg-CO_2e/kg-H_2 would require 96% CO_2 capture and sequestration, which could increase the production cost to $1.64/kg-$H_2$. (Note that this greenhouse gas emissions impact does not include any potential upstream methane emissions.) This production cost also does not include costs to compress, store, or transfer hydrogen for end uses.[63]

Hydrogen cost calculations should account for uncertainty in hydrogen production deployment, operation, and infrastructure, inherent regional variability, and the potential that certain projects may not qualify for federal tax credits.

The methodology outlined in the rules does not consider technoeconomic factors that may have a consequential impact on hydrogen costs, and provided information does not support the basis of abatement costs achievable through the application of hydrogen cofiring, especially absent IRA credits.

[61] U.S. Department of Energy (2023). U.S. National Clean Hydrogen Strategy and Roadmap (link).
[62] Parfomak (2021). Pipeline Transportation of Hydrogen: Regulation, Research, and Policy. Congressional Research Service Report R46700 (link).
[63] NETL (2022). Comparison of Commercial, State of the Art, Fossil Based Hydrogen Production Technologies. DOE/NETL-2022/3241 (link).

Analyses by EPRI and others indicate that there is considerable regional variation and uncertainty around future hydrogen costs, which are generally greater than proposed estimates.

The proposal's cost estimates for hydrogen, $1/kg in 2030 and $0.50/kg in 2035, are not supported by current technologies or hydrogen cost trends and understate uncertainty and regional variation. Using its US-REGEN model, EPRI calculated the levelized cost of hydrogen production with dedicated low-carbon generation (<0.45 kg-CO_2e/kg-H_2) across the U.S. to be between $3 and $5 per kg. This calculation is based on a regional levelized cost of electricity production and the assumption that costs for electrolyzer systems could decrease from today's values.

Table 5. EPRI technoeconomic analysis results for 50 metric tons per day of hydrogen production through electrolysis (in 2021 USD). Source: EPRI (2022).[64]

	Alkaline	**Proton Exchange Membrane**
Total Capital Requirement ($/kW-e)	1,331	2,783
Total Direct Material ($/kW-e)	633	1,196
Electrolyzer Direct Materials Cost ($/kW-e)*	427	934
**Does not include costs for water treatment, hydrogen compression, utilities, and balance of plant, which are required to operate the electrolyzer system*		

EPRI recommends using a hydrogen production cost methodology that accounts for the following:

- **Capital cost uncertainty should be considered in the cost of hydrogen.** In 2021, EPRI developed engineering estimates for alkaline and proton exchange membrane (PEM) systems that can produce 50 metric tons per day. A summary of results is provided in Table 5. The electrolyzer costs from EPRI's 2021 study represent 67% and 78% of the total direct materials cost for the alkaline and PEM units, respectively.

  To account for the fact that electrolyzers are not currently mass produced to supply hydrogen as a fuel and that future economies of scale could impact electrolyzer materials costs, EPRI's analysis attempts to incorporate uncertainty in calculating future production costs. To analyze this uncertainty, the electrolyzer system total capital requirement in US-REGEN analysis ranges from $720 to $2,800 per kW-e[65] which, along with other factors discussed next, results in hydrogen production costs ranging from $3 to $5 per kg.

- **Cost assumptions should consider regional variability.** There is geographic variability in low-carbon hydrogen costs in part because of the regional variation in levelized costs of carbon-free electricity. Electricity production cost has a direct impact on hydrogen cost. Because electricity is

[64] EPRI (2022). *Low-Carbon Energy Supply Technology Cost and Performance Study*. EPRI Report 3002023656 (link). The expected accuracy of these values is defined in the AACE Standard as Class 4 estimates which were produced in part by a qualified engineering, procurement, and construction firm.

[65] The range in potential future total capital requirement is chosen to represent 50% of the higher cost today (that is, cost reductions occur) and today's cost (that is, no cost reductions occur).

the largest operational expense of an electrolytic hydrogen production facility, as shown in Figure 18, more accurate representations of hydrogen production cost are warranted.[66]

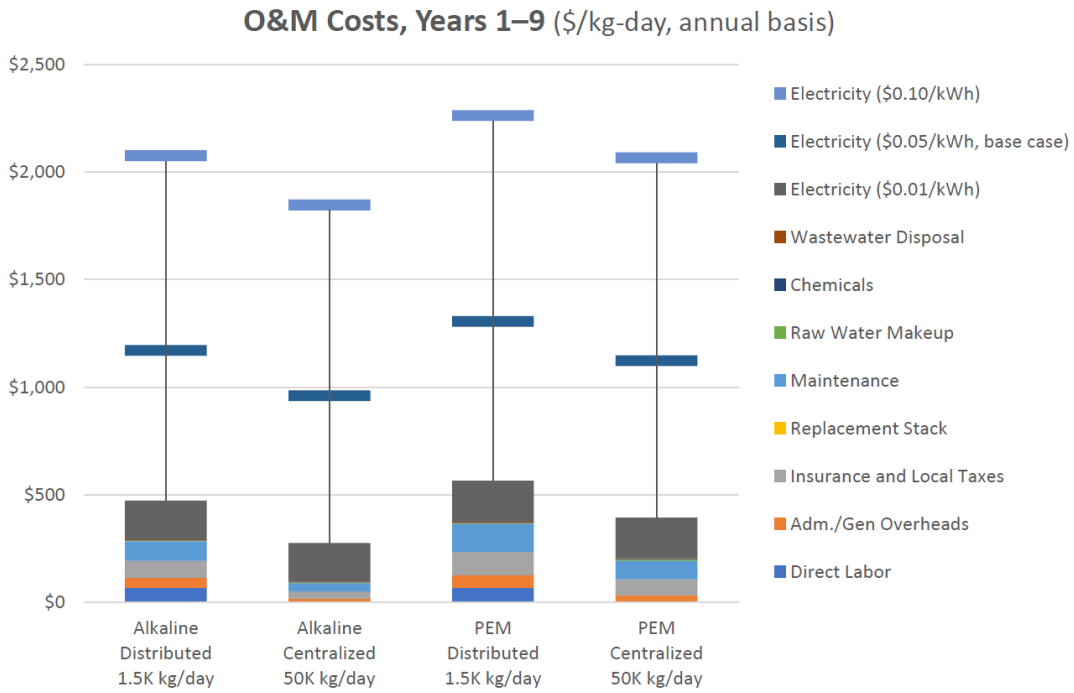


Figure 18. Estimated annual operational expenses for electrolysis facilities by technology and size. Results are for years 1 through 9 because the study assumed a stack replacement in year 10, which would incur significant expense in that year (EPRI, 2023).

- **Evaluating the cost of hydrogen with and without financial incentives presents a more robust analysis of potential costs and benefits.** Estimating hydrogen costs based on tax credit-qualified production fails to fully capture hydrogen-related costs and associated variability. When production tax credits from the U.S. Inflation Reduction Act (IRA) are included (assuming maximum credits from both 45Y and 45V, where the latter credits are available to a project for a 10-year period), EPRI analysis results in a hydrogen production cost range from $0 to $2 per kg. However, this analysis is based on a variety of regional factors that cannot perfectly represent the aggregate of site-specific conditions (for example, availability of infrastructure). Importantly, these ranges do not include hydrogen transmission, distribution, storage, and additional compression beyond the pressure produced by the electrolyzer system.

  Clean hydrogen credits under 45V in IRA are based on a commence construction date of 2032. Given the large ramp-up in production required to support potential increased hydrogen demand under the cofiring pathway in the rules between 2032 and 2038, much of this incremental hydrogen production capacity would not be eligible unless IRA credits are extended.

  Figure 19 illustrates the potential regional variation in levelized hydrogen costs, given how regions vary in the quality of their wind and solar resources, costs of technologies (for example,

[66] EPRI (2023). *Cost and Performance Summary—Electrolysis*. EPRI Report 3002026206 (link).

because of different labor rates), policy support, and other factors. This figure suggests that assumptions of \$0.5/kg-H_2 are lower than projections with IRA and substantially below estimates without tax credits. The point estimates used omit important regional variation in the economics of hydrogen. Comparing the two panels of this figure highlights how uncertainty about future capital cost declines for electrolyzers can influence future hydrogen prices.

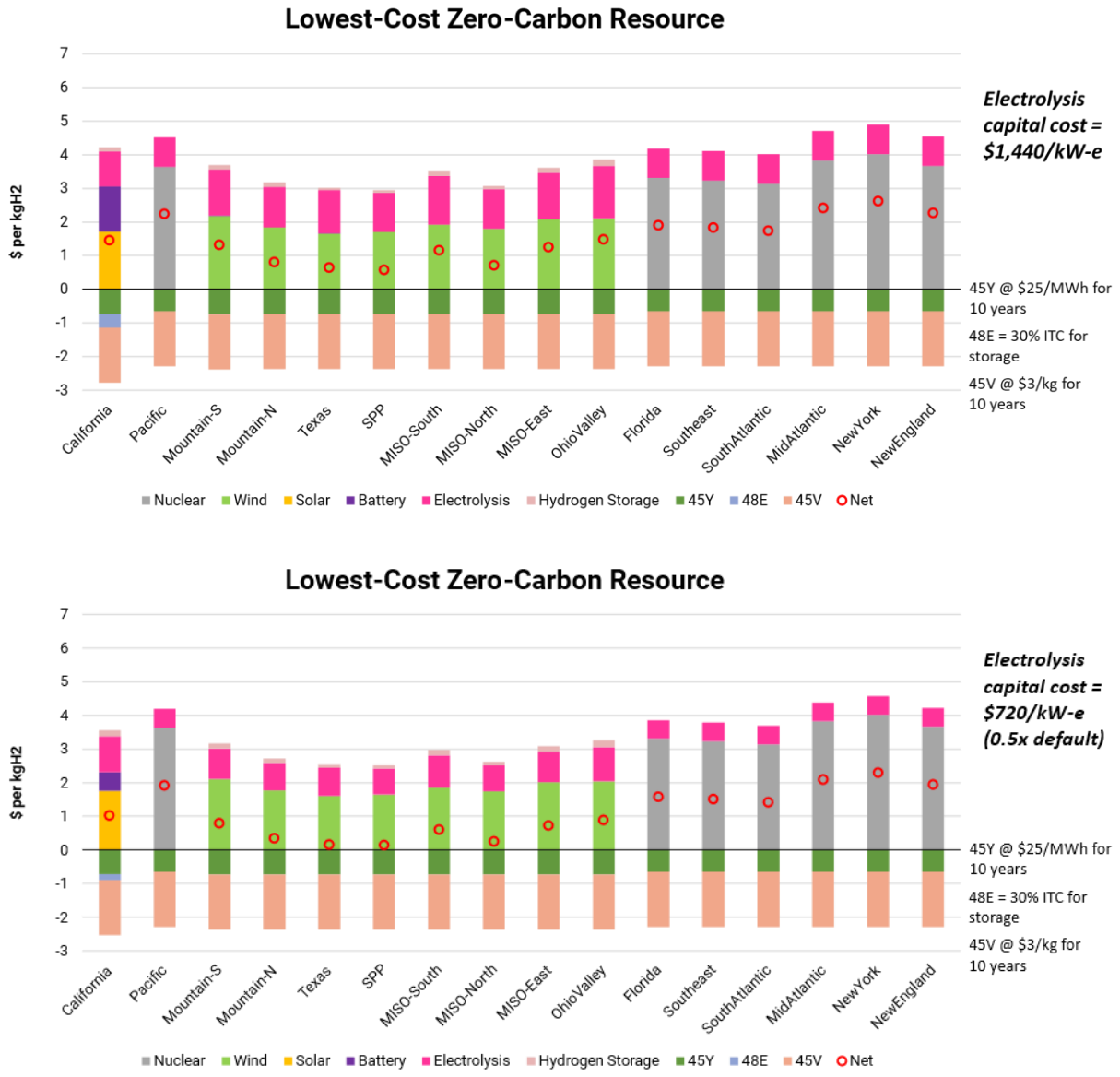


Figure 19. EPRI analysis of estimated levelized production cost of hydrogen with IRA incentives. Electrolytic hydrogen costs are based on dedicated electricity supply assuming capital costs of electrolysis of \$1,440/kW-e (top panel) and \$720/kW-e (bottom panel).

In addition, the IRA provides a temporary reprieve from projected higher, market-driven hydrogen costs. In modeling from EPRI's US-REGEN, production prices increase after the 45V subsidy period expires, as shown in Figure 20. Note that the figure shows production costs and

does not include the total delivered costs (transport, storage, and distribution), which would be higher and non-negative for most applications.

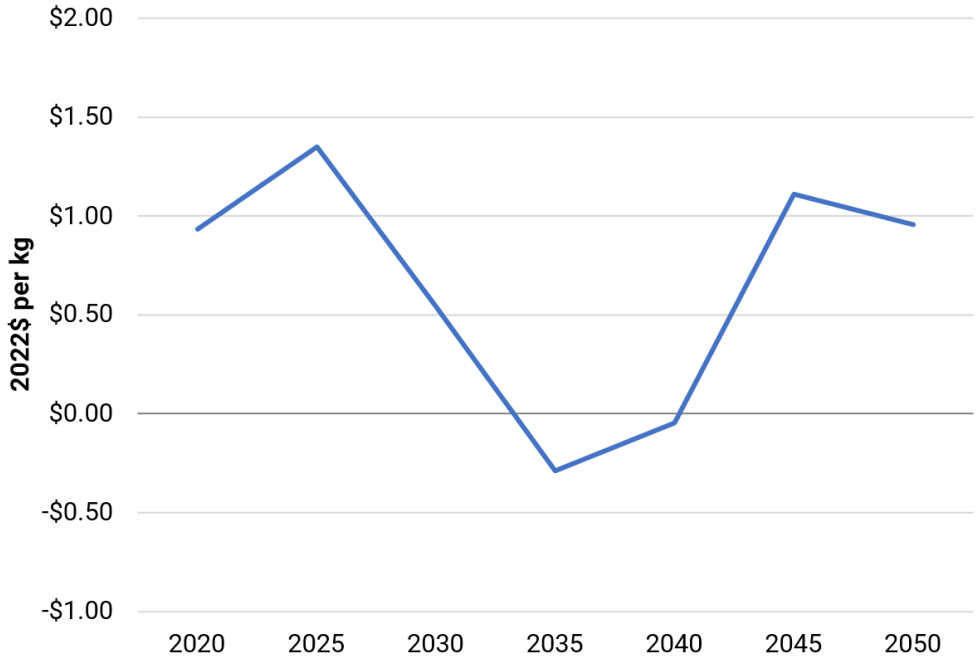


Figure 20. EPRI analysis of estimated hydrogen production costs only (that is, not including delivery costs). Values show production-weighted average price across regions. Results from EPRI's US-REGEN model in a scenario with IRA 45V credits assuming hourly matching and additionality.

- **Cost assumptions should include hydrogen transport and storage costs.** No publicly available data exist for market-scale, low-carbon hydrogen economy costs (that is, the combined costs of production, transport, storage, and delivery). According to DOE's "U.S. National Clean Hydrogen Strategy and Roadmap," incorporating post-production costs could add between $0.30 to $3.30 per kilogram of produced hydrogen if optimal and advanced technologies/practices are deployed at scale by 2030. These costs are derived from "data based on cost-downs shared from leading-edge companies who have deployed at demonstration scale (or larger)," as illustrated in Figure 21.[67] DOE's estimates do not include costs to retrofit or modify power generation equipment, controls, and so on, which may be required to blend hydrogen. These costs are not well defined, as discussed in subsequent comments.

[67] U.S. Department of Energy (2023). U.S. National Clean Hydrogen Strategy and Roadmap (link).

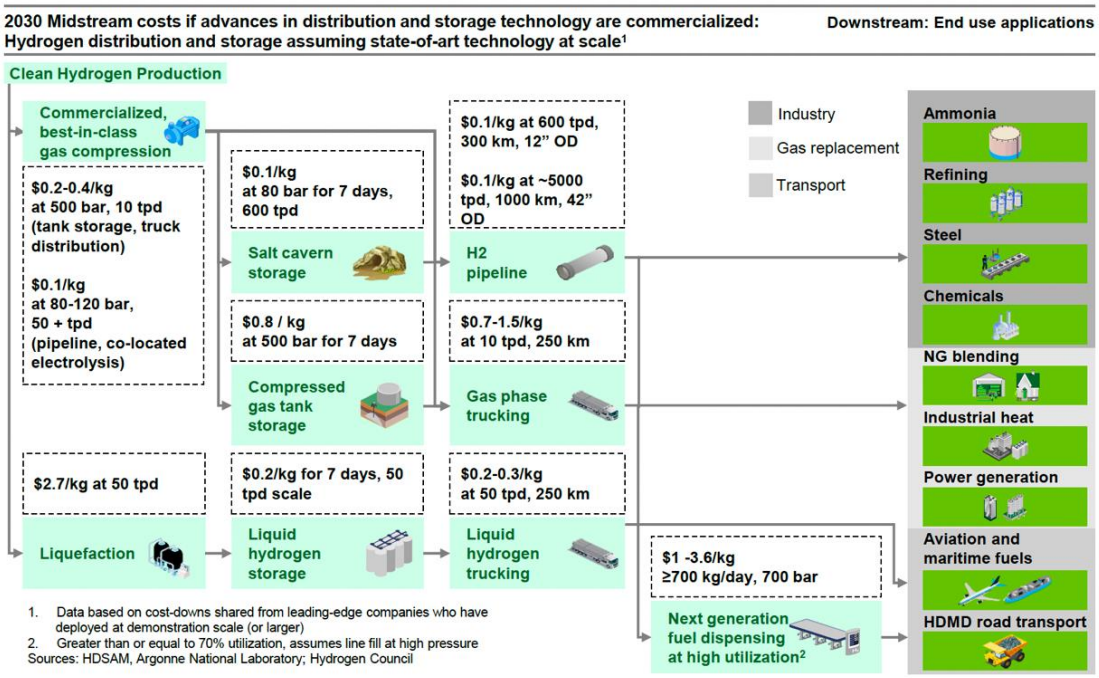


Figure 25: Industry-informed estimates of midstream costs by 2030 and potential end uses. Repurposed from DOE's report, Pathways to Commercial Liftoff: Clean Hydrogen.

Figure 21. U.S. DOE midstream hydrogen costs assuming that advanced technologies are commercialized. DOE notes that these estimates are projected 2030 costs if certain advances in technologies are commercialized (DOE, 2023).

- **Hydrogen hub deployment could provide valuable information.** DOE is involved in many activities aimed at creating a sustainable hydrogen economy, the largest of which is FOA 2779 on H2Hubs. EPRI suggests that hydrogen hubs can provide a potential pathway to expand hydrogen availability for the energy economy, but the timing and scale of hubs are not consistent with the proposed rules. In this effort, "DOE expects that hydrogen production technologies integrated into H2Hubs will be capable of at least 50–100 metric tons (MT) per day… [and] DOE envisions selecting six (6) to ten (10) H2Hubs." The upper end of these criteria would translate to 0.41 MMT of annual production[68] for the total investment of $12–14B (includes federal and non-federal contributions) over the 10- to 12-year period (defined by the hub).

The rules should account for the limited operating experience on hydrogen cofiring, commercial availability of hydrogen-capable gas turbines, operational profiles, retrofit costs, fuel system and balance-of-plant modifications, and other unit-specific capabilities impacted by hydrogen cofiring.

As DOE acknowledges in the U.S. National Clean Hydrogen Strategy and Roadmap, "Large-scale deployments of hydrogen energy storage will require reductions in the cost of electrolyzers and fuel cells, the development of low-NOx combustion technologies for use in hydrogen turbines, and the development of new, low-cost bulk hydrogen storage technologies that are not geographically constrained" and further describes early-stage research projects it is funding. EPRI agrees with DOE's assessment that hydrogen

[68] This calculation assumes 10 H2Hubs that each produce 100 metric tons per day with an annual capacity factor of 90%.

for gas turbines is not yet a commercial-ready solution and believes that the following aspects must be addressed to ensure reliable and cost-effective operation:

- **Commercial availability.** Gas turbine original equipment manufacturers (OEMs) are assessing the different combustion characteristics of hydrogen and methane to determine the potential of hydrogen blending for a given unit. Publicly available information on OEMs' efforts to blend hydrogen in their units is limited, but one project funded in part by DOE documents efforts to validate hydrogen blending spanning more than 10 years.[69]

  EPRI is aware of a small number of combustion systems that are quoted to be capable of hydrogen blending above 50% by volume. To be compatible with hydrogen blending at any amount, power plant operators should undertake a unit-specific evaluation and consider factors such as compatibility of equipment and infrastructure, for example, conforming with codes and standards, capabilities of environmental control technologies, sufficiency of site safety and operating procedures, and adequacy of control software and measurements. EPRI has documented a summary of capabilities provided by OEMs, which should be viewed as a preliminary, high-level summary and not a complete analysis.[70]

- **Operational profiles.** EPRI has participated in five tests on blending hydrogen in commercial natural gas power generation assets. The units tested were a 45-MWe GE aeroderivative unit, an 18-MWe Wärtsilä RICE unit, a 265 MWe Mitsubishi 501G unit, and a 246-MWe Siemens SGT6-6000G unit. In all cases, these units were selected because very few modifications were needed to blend hydrogen. No major modifications to hardware or software were performed prior to testing. For two of these tests, EPRI has documented the results—including emissions and performance data—in publicly available reports.[71] For all units, testing was limited to short durations (approximately 1 hour per run for most units) at multiple load points (generally between 25% and 100% of full load capacity). The total operating time with hydrogen blend ranged from 3.5 hours to 12 hours, and a limited number of parameters were evaluated during each test. The maximum amount of time any unit operated on hydrogen blending was 5 hours. Testing was limited primarily by the availability of hydrogen at the sites. In all cases, hydrogen was delivered in tube trailers.

  Further learnings needed include:

  - **Unit startup and planned shutdown on blended hydrogen to determine safe practices.** Blending hydrogen has greater risks during operating periods with lower airflows. Flashback and ignition of hydrogen flames, especially at pressurized conditions,

[69] Schonewald (2012). DOE Advanced IGCC/Hydrogen Gas Turbine Program at General Electric (link).
[70] EPRI (2023). *Technology Insights Brief: Hydrogen-Capable Gas Turbines for Deep Decarbonization*. EPRI Report 3002017544 (link).
[71] EPRI (2023). Executive Summary—Hydrogen Blending Demonstration at UMERC's A. J. Mihm Generating Station: Wärtsilä 18V50SG Reciprocating Internal Combustion Engine. EPRI Report 3002026305 (link).
EPRI (2022). *Executive Summary: Hydrogen Cofiring Demonstration at New York Power Authority's Brentwood Site: GE LM6000 Gas Turbine*. EPRI Report 3002025166 (link).

are of concern. EPRI testing so far has not been able to include startup evaluations, and experiences are not well documented in literature.[72]

- **Interrupted operation on blended hydrogen to determine safe practices.** EPRI has not been able to demonstrate safe operational practices to mitigate hydrogen accumulation or flame stability changes during deviations in operations.
- **Unit turndown operations on blended hydrogen to monitor impacts on emissions and performance.** Each unit type will have its own set of characteristics and compatibility with hydrogen blending. Consistent evaluations would provide data needed to create new, industry-wide standards for safe and reliable operation over various conditions.

- **Retrofit costs.** Although retrofits to both hardware and software may be required to convert a unit to hydrogen blends, the actual costs of retrofitting for hydrogen power generation are not well documented. Current, larger-frame/advanced-class combined-cycle gas turbines have better heat rates/efficiencies than previous models. However, units built today may still need upgrades and new infrastructure to meet 96% hydrogen blending goals.[73] Combined with lower capacity factors, the added costs of retrofits for hydrogen blending may not be economical for low-load operations. In addition, gas turbine efficiencies are lower during low-load operation, requiring more hydrogen (percent volume) to achieve reductions in CO_2 emissions.
- **Fuel system and balance-of-plant modifications.** The gas turbine fuel delivery system will change with hydrogen blending for code compliance and overall safety. In addition to the hydrogen supply and mixing with natural gas, additional venting, inert gas purging, and instrumentation may be required. Any local hydrogen storage requirements may add changes for compliance and safety. Blended fuel gas piping downstream of the hydrogen gas addition to the gas turbine itself will require rigorous review for code applicability and sizing to ensure that the velocity and system pressure drop meet all applicable design criteria for full gas turbine operation. Hydrogen storage, generation, blending, and delivery are all possible changes that will impact the plant's general arrangement. It should be expected that, at any site, adding hydrogen will require changes to the site general arrangement. Area classifications, such as hazardous areas with hydrogen, will also affect the general arrangement, drawings, and site access. Hydrogen combustion results in changes in exhaust products, and those changes will drive the need to evaluate other plant systems such as heat recovery steam generators (HRSGs), duct burners, and exhaust emissions after-treatments systems such as ammonia and CO catalysts. Careful considerations must be made for emissions reporting, as the hydrogen products add complexity in characterizing the NOx emissions based on traditional methods.[74] The HRSG is subject to the gas turbine exhaust conditions and can be impacted by the exhaust flow rate, temperature, and composition. Gas turbine controls could be adjusted with hydrogen to account for changes in emissions or performance of the gas turbine with hydrogen. The change in fuel to the gas turbine may be significant to duct burner operations for those sites which include auxiliary firing. The fuel source may be common between duct burners and the gas turbine. Thus, any change to the

[72] One example is available by Banihabib and Assadi (2022). A Hydrogen-Fueled Micro Gas Turbine Unit for Carbon-Free Heat and Power Generation. Sustainability, 14(20): 13305 (link).
[73] Ibid.
[74] Douglas et al. (2022). Pollutant Emissions Reporting and Performance Considerations for Hydrogen–Hydrocarbon Fuels in Gas Turbines. ASME Journal of Engineering for Gas Turbines and Power, 144(9): 091003 (link).

gas turbine fuel may either require a change to duct burner operations or specific piping and control to operate the duct burners on only natural gas.

- **Unit-specific capabilities:** Not all power generation gas turbines operating or available in the market today are capable of blending hydrogen, with many limited to 50% by volume or less. Each unit must undergo its own analysis to determine if and how much hydrogen can be blended and whether costs required to retrofit current units are economical in low- or intermediate-load operations. Unit-specific evaluations should also include the availability of hydrogen fuel to ensure that operating profiles match fuel delivery.

Water consumption and wastewater management should be considered when evaluating hydrogen cofiring. Electrolysis for hydrogen production requires significant amounts of water , including for the direct production of hydrogen and balance-of-plant processes such as cooling.

Electrolysis processes require water resources – not only high-purity water for the direct production of hydrogen, but also for balance-of-plant systems such as cooling water (Figure 22 and Figure 23).[75] Electrolyzers produce waste heat, which requires cooling to maintain a constant temperature during operation. As hydrogen is produced from the electrolyzers, hydrogen and water separation steps increase the hydrogen purity and produce low-volume wastewater that should be evaluated for purity and potential reuse. Hydrogen compression is typically required to meet the pressure requirements of the end-use application. Compression produces a heat load that requires cooling, as well. Wet or hybrid (wet/dry) cooling applications produce a cooling water blowdown stream that requires treatment and disposal.[76]

Water availability varies by region. In water-scarce regions (for example, the southwest U.S.), water quantity is limited, and water quality may be impaired.[77] In these regions, water treatment systems may observe a higher rejection rate, and wastewater may need to be managed on site, requiring treatment systems, such as reverse osmosis, thermal evaporators, or evaporation ponds.

Feedwater quality requirements vary across electrolyzer manufacturers, but deionized water is typically necessary, such as ASTM Type I, II, or III.[78] Sources may include freshwater (for example, surface water, groundwater, or municipal effluent), brackish water, or seawater and must be treated to high purity standards for reliable electrolyzer operations. Treatment trains typically include clarification/filtration, reserve osmosis, electrodeionization, and ion exchange. High-purity treatment systems produce a waste stream (“brine” or “concentrate”), which requires proper disposal.

[75] EPRI (2022). *Insight Report on Electrolyzer Technologies*. EPRI Report 3002023084 (link).
[76] EPRI (2023). *Infographics: Water Usage in Electrolysis for Hydrogen Production*. EPRI Report 3002027351 (link).
[77] EPRI (2023). *Water Considerations for the Energy Transformation*. EPRI Report 3002027353 (link).
[78] EPRI (2023). *Infographics: Water Usage in Electrolysis for Hydrogen Production*. EPRI Report 3002027351 (link).

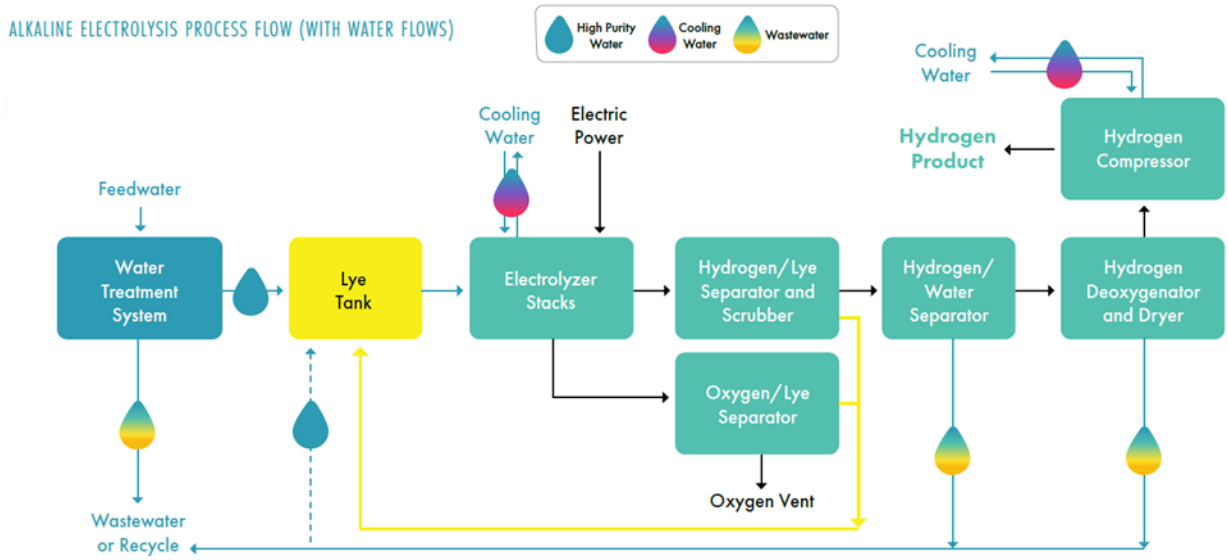


Figure 22. Typical alkaline electrolysis process flow diagram. This representation of a process flow for an alkaline electrolysis system identifies locations of water use and wastewater generation. Source: EPRI (2023).[79]

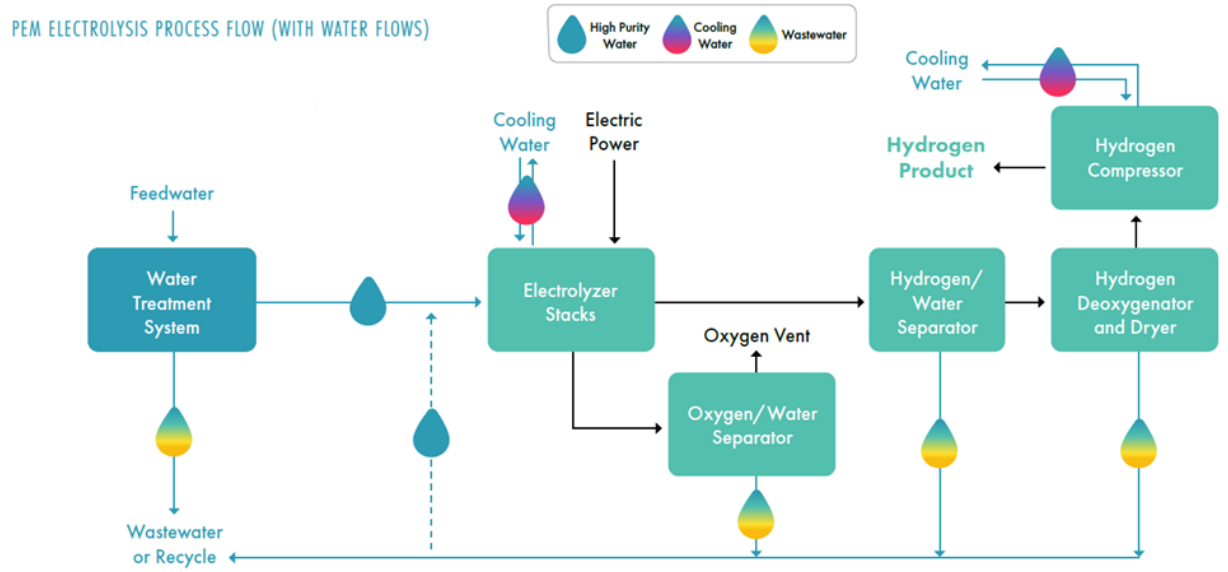


Figure 23. Typical PEM electrolysis process flow diagram. This representation of a process flow for a PEM electrolysis system identifies locations of water use and wastewater generation. Source: EPRI (2023).[80]

Table 6 summarizes estimated water withdrawal, consumption, and discharge rates for alkaline and PEM electrolysis systems. The estimated water usage rates for alkaline electrolysis are 12.6 gal/kg-H_2 withdrawal, 7.8 gal/kg-H_2 consumption, and 4.8 gal/kg-H_2 discharge. The total water usage rates for PEM

[79] EPRI (2023). *Infographics: Water Usage in Electrolysis for Hydrogen Production*. EPRI Report 3002027351 (link).
[80] EPRI (2023). *Infographics: Water Usage in Electrolysis for Hydrogen Production*. EPRI Report 3002027351 (link).

electrolysis are 14.2 gal/kg-H_2 withdrawal, 9.7 gal/kg-H_2 consumption, and 4.6 gal/kg-H_2 discharge.[81] Assumptions for the high-purity treatment system include a 44% treatment system rejection rate. Assumptions for the recirculating evaporative cooling system include a 10 °C range and cooling tower cycles of a concentration of 4.0.

Table 6. Water usage rates for alkaline and PEM electrolysis. This table summarizes water withdrawal, consumption, and discharge rates for alkaline and PEM electrolysis hydrogen production systems. Source: EPRI (2023).[82]

	Water Withdrawal (gal/kg-H_2)	**Water Consumption (gal/kg-H_2)**	**Water Discharge (gal/kg-H_2)**
Alkaline Electrolysis	12.6	7.8	4.8
PEM Electrolysis	14.2	9.7	4.6

Cofiring hydrogen at gas plants may not be the highest-value and lowest-abatement-cost use due to potential limitations on the extent of near-term hydrogen production and delivery.

Practical and technical limitations on the extent of near-term hydrogen production and delivery raise questions about whether cofiring hydrogen at gas plants is the highest-value and lowest-abatement-cost use. Economy-wide net-zero scenarios from EPRI and others indicate that, without hydrogen tax credits, there is relatively little direct use of hydrogen for electricity generation.[83] Although power sector net-zero pathways suggest that hydrogen can be an important long-duration storage option, recent EPRI modeling suggests that deployment tends to increase only as the system nears net-zero emissions—especially when carbon removal options are not available (Figure 24)[84]—and hydrogen's economics and high marginal cost could imply that it is used with lower capacity factors (Figure 3), not over 50% as the rules suggest.

[81] EPRI (2023). *Environmental Impacts of Alternative Energy Carriers in Power Generation: Water Use*. EPRI Report 3002026600 (link).
[82] EPRI (2023). *Environmental Impacts of Alternative Energy Carriers in Power Generation: Water Use*. EPRI Report 3002026600 (link).
[83] EPRI (2022). *Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis*. EPRI Report 3002024882 (link). Browning et al. (2023). Net-Zero CO_2 by 2050 Scenarios for the United States in the Energy Modeling Forum 37 Study. Energy and Climate Change, 4: 100104 (link).
[84] EPRI (2021). *Powering Decarbonization: Strategies for Net-Zero CO_2 Emissions*. EPRI Report 3002020700 (link). Bistline and Blanford (2021). Impact of Carbon Dioxide Removal Technologies on Deep Decarbonization of the Electric Power Sector. Nature Communications, 12: 3732 (link).

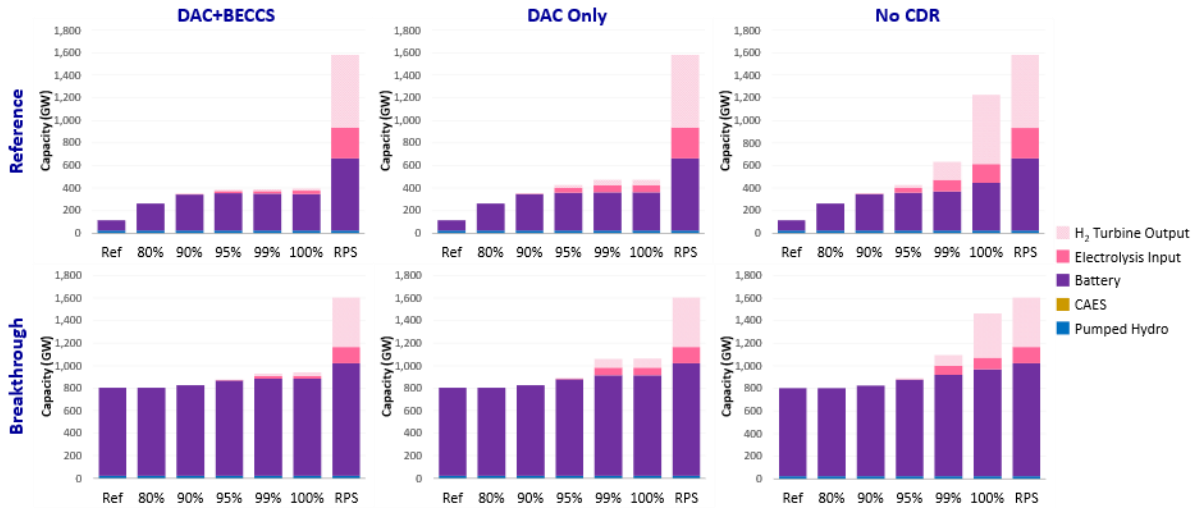


Figure 24. Modeled energy storage capacity by technology across different electric sector CO_2 reduction targets (% reductions relative to 2005 levels). Sensitivities include different renewable cost assumptions (rows) and carbon dioxide removal (CDR) availability (columns). *Ref* refers to the reference scenario without CO_2 policy, and *RPS* refers to the zero-emissions scenario with renewables only. Values are outputs from EPRI's US-REGEN model.[85]

The resources used to produce hydrogen for power generation have the potential to increase overall costs and emissions.

Depending on the hydrogen production pathway, inadequate coverage of upstream emissions from hydrogen production can erode the emissions reductions associated with cofiring-based pathways, potentially increasing costs and emissions. Although the rules define *low-GHG hydrogen* as the lowest-emitting tier from IRA's 45V credits,[86] details about the implementation and enforcement of these definitions can potentially lead to a range of emissions associated with production, especially for electrolytic hydrogen, given complex substitution patterns on electricity grids.[87]

Based on EPRI modeling and analysis, the combination of hydrogen production tax credits from 45V with compliance obligations for hydrogen-fired generation at natural gas power plants under the proposed 111 rules can result in incentives to incur significant roundtrip efficiency losses through conversion of electricity to hydrogen and reconversion of that hydrogen back to electricity.

[85] EPRI (2021). *Powering Decarbonization: Strategies for Net-Zero CO_2 Emissions*. EPRI Report 3002020700 (link).
Bistline and Blanford (2021). Impact of Carbon Dioxide Removal Technologies on Deep Decarbonization of the Electric Power Sector. Nature Communications, 12: 3732 (link).
[86] Specifically, it is "produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen (kg-CO_2e/kg-H_2) on a well-to-gate basis consistent with the system boundary established in IRC section 45V (Credit for Production of Clean Hydrogen) of the IRA" (Rules, p. 244–245).
[87] Gagnon et al. (2022). Short-Run Marginal Emissions Rates Omit Important Impacts of Electric-Sector Interventions. Proceedings of the National Academy of Sciences, 119(49): E2211624119 (link).
Ricks, Xu, and Jenkins (2023). Minimizing Emissions from Grid-Based Hydrogen Production in the United States. Environmental Research Letters, 18: 014025 (link).

2.4. Natural Gas Cofiring at Coal Plants

Section Summary: Natural gas cofiring at coal plants can result in lower emissions, reduction in environmental controls, and reduced maintenance and fuel costs, in some instances. Although several coal-designed plants have converted to gas cofiring, the cost, performance impacts, and limitations regarding the maximum quantity of gas to be cofired depend on site-specific factors.

The feasibility and cost assumptions associated with natural gas cofiring at coal plants should include site-specific variances in plant designs, operations, coal quality, capacity, and location.

Gas cofiring of coal-designed units offers the benefits of lower base emissions, a reduction or elimination of the need to add back-end environmental controls, reduced O&M, and—when the price of gas is lower than coal—a reduction in fuel costs. Gas cofiring may also offer added benefit with respect to combustion stability, resulting in the ability to fire lower-cost/lower-quality coals, as well as less volatile opportunity fuels. Finally, the increased combustion stability inherent to the more volatile gas may also be beneficial in supporting the increasing need to make coal-fired boilers more flexible with respect to load range and transient conditions.[88]

The above notwithstanding, there are site-specific challenges with cofiring gas in a unit designed for coal that were not adequately considered. Although several coal-designed plants have successfully converted to gas cofiring,[89] the cost, performance impacts, and limitations regarding the maximum quantity of gas to be cofired depend on several site-specific factors. These factors may include unit design, operating requirements, gas availability, coal quality, impacts on unit performance (for example, impacts on heat rate, furnace exit gas temperature, and radiant heat distribution), and other considerations.

Related considerations include the following:

- **A reduction in net megawatt output to the grid.** Because of the higher water contained in the combustion gas when coal is displaced by natural gas, a reduction in boiler efficiency/increase in unit heat rate will occur. This will be proportional to the ratio of natural gas cofired. Further, a deterioration in boiler efficiency and increase in unit heat rate will occur for most units when operated at heat inputs exceeding their design. Accordingly, units designed for 100% coal firing may experience a reduction in net megawatt output to the grid proportional to the quantity of coal displaced by gas. In addition to an increase in the heat rate of the cofired boiler, a calculation of resulting net CO_2 levels may need to consider the availability and efficiency of backup power sources. There are, however, some offsetting factors that will reduce this penalty, such as reductions in plant energy requirements (for example, pulverizers, coal crushers, and certain environmental controls), unburned carbon in ash, sootblowing for removal of slagging and fouling on heat transfer surfaces, and excess air requirements.

[88] EPRI (2023). *Combustion and Fuel Quality Impacts from Gas Cofiring: Review of Coal-Fired Unit with Natural Gas Cofiring*. EPRI Report 3002024346 (link).
EPRI (2021). *Gas Co-Firing Workshop/Roundtable Video*. EPRI Report 3002022848 (link).
EPRI (2000). *Gas Cofiring Assessment for Coal-Fired Utility Boilers*. EPRI Report 1000513 (link).
EPRI (2000). *Gas Cofiring Evaluation on a Tangential PC-Fired Boiler*. EPRI Report 1000449 (link).
EPRI (1997). *Retrofit NO_x Control Guidelines for Gas- and Oil-Fired Boilers Version 2*. EPRI Report 108181 (link).
[89] EPRI (2022). *Database of Gas Co-Firing Units*. EPRI Report 3002021903 (link).

- **Cost and challenges of gas supply.** Most gas cofiring retrofits to date have occurred where the gas source was available and plentiful on site or relatively nearby. But for more universal applicability, it should be recognized that many coal plants are located in remote areas, resulting in substantial costs and permitting issues associated with the installation of required gas supply piping to the plant. Studies have reported that costs may be in the range of $4 million to greater than $10 million per mile, with project-specific costs dependent on rural or urban setting, pipe diameter, terrain, quantity of gas to be transferred, local labor rates, and other factors.

- **Year-round gas availability.** Assessments should account for the cost of firm pipeline transportation and year-round availability of the large gas quantities needed to supply 40% of the total heat input to large power-producing boilers. For example, a 600-MW unit with a heat rate of 9,500 Btu/kW-hr looking to displace 40% coal will require approximately 2.3 million SCF/hr of natural gas.

- **Furnace heat distribution.** Natural gas will fully combust within a much shorter distance in comparison to coal flames. Although heat distribution appears manageable, it depends on the design of the unit (for example, presenting more of an issue for furnaces with lower heat release rates, such as those designed for lower-rank coals). To assess and implement the necessary combustion modifications to resolve this issue for specific applications, EPRI has and will continue to conduct computational fluid dynamics modeling studies to better assess and seek ways to minimize this issue for specific boiler designs and operating scenarios. An excerpt of the results of a modeled study for a base case of 100% coal and parametric cases of 10% and 50% natural gas cofiring is shown in Figure 25.

- **Methane releases.** Although regulations could be in place to minimize/eliminate natural gas leakage, upset conditions may occur. Sources may include gas transport piping, storage, or releases during the combustion process.

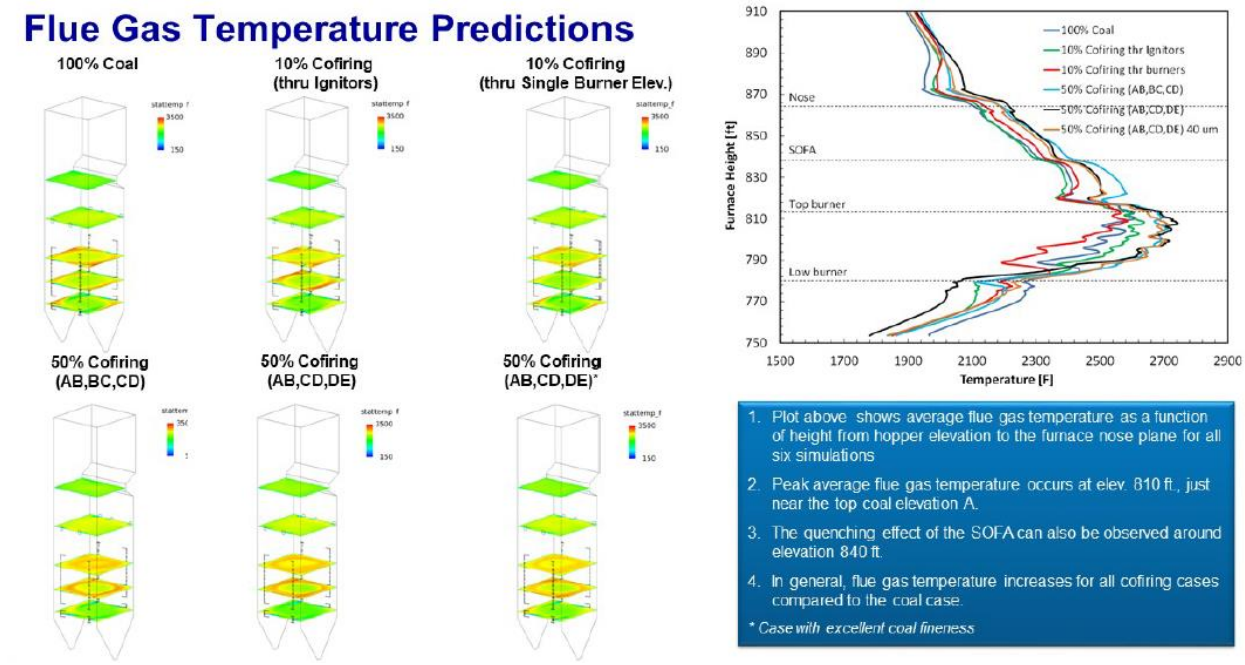


Figure 25. Modeled temperatures across different natural gas cofiring assumptions at coal plants.[90]

[90] EPRI (2018). *Studies on Coal and Natural Gas Cofiring: Simulation of Tangentially Fired Furnace Cofiring Strategies*. EPRI Report 3002013004 (link).

3. System Impacts

3.1. Resource Adequacy and Reliability

Section Summary: Statements about the projected resource adequacy and reliability impacts of the proposed rules[91] should be based on more complete characterizations of the regulations and on modeling that includes key dynamics that may have implications for these areas. Reliability of the power grid is typically evaluated for both resource adequacy and operating reliability (or security). Although the rules and supporting documentation appear to make claims about both resource adequacy and grid operational reliability, the scope of the assessment appears to focus on adequacy only, which should be clarified. In addition, the resource adequacy analysis excludes probabilistic assessments such as loss of load expectation, expected unserved energy, or loss of load hours, which are important to accurately assess resource adequacy of the system under a rapidly changing mix of generation, as projected by EPA's IPM model. Further, IPM does not have capabilities to project impacts on grid operating reliability.

The rules and supporting documentation should clearly assess both resource adequacy and grid operational reliability.

The rules makes statements about both resource adequacy and reliability—"EPA has carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals" (Rules, p. 27)—and in the TSD—"This document… describes projected resource adequacy and reliability impacts of the proposed rules" (RA TSD, p. 2). However, it is unclear if these statements intend to comment on both resource adequacy and grid operational reliability. The North American Electric Reliability Corporation (NERC) defines[92] bulk electric system reliability as consisting of two distinct aspects:

1. Adequacy, which relates to the resource adequacy aspect primarily referenced in the proposed rules and analysis
2. Operating reliability, which relates to the performance of the grid under contingencies

The rules acknowledge this distinction in the TSD[93] but make statements elsewhere (in the rules and TSD) suggesting that the scope of the assessment is broader than what was conducted. Changes to the supply resource mix associated with compliance with the proposed rules may impact both the adequacy and operating reliability of the grid. The scope and limitations of the assessment should be clarified in each instance in which it is referenced.

The IPM modeling has several limitations for assessing resource adequacy and reliability impacts.

EPA's statement that it "has carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals" (Rules, p. 27) refers to analysis using IPM in the TSD on

[91] Both in the rules and in the technical support document: U.S. Environmental Protection Agency (2023). Resource Adequacy Analysis Technical Support Document (link).
[92] NERC (2013). Reliability Terminology (link).
[93] "As used here, the term resource adequacy is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region, while reliability includes the ability to deliver the resources to the loads, such that the overall power grid remains stable" (RA TSD, p. 2).

resource adequacy. This modeling makes several simplifying assumptions that may have implications for resource adequacy:

- The approach to simplify the temporal resolution of system operations—and consequently investments and retirements—likely leads to an undervaluation of firm capacity and energy storage, as well as to incomplete coverage of variability of load and renewable resources. These simplifications likely miss extreme periods when system load is high and variable renewable output is low and vice versa, as well as miss system requirements to rapidly ramp output – both of which are critical for assessing resource adequacy. For example, as illustrated in Figure 26 in Section 5.1, this method could overestimate potential solar output during evening and nighttime periods. More broadly, these simplifications mean that potential resource adequacy risks based on weather extremes, weather-dependent generator performance, and other external risk drivers are excluded from the assessment.[94]
- The modeling does not account for the possibility of early nuclear power plant retirements and instead assumes that plants stay online until predefined retirement dates. IRA tax credits can depress wholesale electricity prices, which may already be low if natural gas prices are low. These low prices can lead to earlier-than-expected retirements of existing capacity, such as nuclear power plants, if expectations for going-forward costs exceed anticipated revenues. This assumption overstates the amount of firm capacity on the system.
- The representation of the proposed rules in IPM covers only existing source standards for coal units and the first two phases of new source standards, leaving the other elements for a spreadsheet analysis.

Not only do these assumptions have direct impacts on assessments of resource adequacy, but as described in Section 5.1, many of these simplifications likely understate the impacts of the proposed rules with regard to the baseline without these regulations. Further, if EPA intends for its analysis to include potential impacts on operational reliability, more granular unit commitment, power flow, short-circuit, and dynamic stability reliability models of regional systems will be required.

These factors should be addressed to improve the accuracy of the resource adequacy and reliability assessments. EPRI research has illustrated how detailed analytical frameworks for scenario development, resource portfolio planning, and operating reliability evaluation are important for understanding changes in supply, delivery, and end-use systems.[95] These factors vary by region and scenario (including policy assumptions), so a more comprehensive analysis would need to be conducted to evaluate the magnitude of impact related to the points above.

Note that the incremental impacts on reliability and resource adequacy of power system decarbonization are ambiguous and vary by region and system, policy design, metrics, and assumptions about the counterfactual baseline (for example, forced outage rates over time, correlated outages during extreme weather events, transmission expansion), especially because these changes may impact both resource additions and retirements. These factors are context- and scenario-specific and require detailed regional

[94] EPRI (2023). Resource Adequacy Knowledge Center (link).
Carvallo et al. (2023). A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems. LBNL (link).
[95] EPRI (2023). *Integrated Strategic System Planning Initiative: Modeling Framework, Demonstration Study Results, and Key Insights*. EPRI Report 3002027931 (link).
EPRI (2023). Resource Adequacy Knowledge Center (link).

analysis to evaluate, making it challenging to make ex-ante assessments about the direction and degree of system reliability impacts.

Depending on a range of factors, EPRI's research suggests that projecting current planning reserve margins (PRMs) forward to 2050 cannot be assumed to result in the desired resource adequacy outcomes. In the context of a rapidly developing generation shift, probabilistic assessment of resource adequacy—including loss of load expectation, expected unserved energy, and loss of load hour assessments—should be conducted to verify the resource adequacy outcomes of the future system.

IPM modeling incorporates an adequacy constraint to ensure that generation supply is sufficient to meet the PRM provided from previous NERC assessments. The use of PRMs has been pervasive in expansion planning models based on historical evidence to suggest that meeting a PRM target with appropriate generation-type capacity values would result in a portfolio that would likely meet the loss of load expectation (LOLE) resource adequacy criterion active in many jurisdictions.[96] EPRI research indicates that probabilistic assessments of LOLE, expected unserved energy, and loss of load hour assessments are important for assessing resource adequacy outcomes of future regional power systems.[97] These assessments can then inform planning reserve margins, but the use of existing planning reserve margins without verification using the probabilistic assessment is not sufficient to ensure resource adequacy.

Sensitivity analysis should be performed to examine the impact of future plant reliability and flexibility—especially for emerging technologies and aging assets.

It is expected that emerging technologies exhibit a learning rate in plant reliability and performance at the start of their life and a decay rate toward the end of the asset life, leading to a bathtub curve, which is not guaranteed to be symmetrical in shape.[98] Reduced operational flexibility is expected for certain BSER approaches, potentially influencing reliability outcomes in high-renewables systems.[99]

Limited operational experience is available to substantiate assessments of the future capacity value of CCS-equipped capacity or hydrogen-fired turbines over the long run (as described in Sections 2.2 and 2.3), beyond that which can be inferred from existing resources. The rule's modeling should account for variance in reliability when compared with historical thermal plant performance (for example, forced outage rate, maintenance rate, and flexibility of the associated plant). These secondary effects are worth exploring to understand resource adequacy risks along the transition path to future systems.

Rapidly accelerated retirement of generation or step changes in the capacity factor of specific generation types may conceivably result in investment and operation externalities for the upstream fuel supply chain that may, in turn, influence the availability of generation.

Furthermore, uncertainty related to technology development milestones being reached and project delivery risk may reasonably create the potential for delayed availability of thermal generating resources with CCS or hydrogen cofiring. These factors could mean that existing generation resources may be

[96] Energy Systems Integration Group (2022). Redefining Resource Adequacy for Modern Power Systems (link).
[97] EPRI (2023). Resource Adequacy Knowledge Center (link).
[98] EPRI (2019). *Considering Generator Cycling in Resource Adequacy: 2018 Technical Update*. EPRI Report 3002013488 (link).
[99] EPRI (2016). *Flexible Operation of Current and Next-Generation Fossil Plants With and Without Carbon Capture*. EPRI Report 3002006388 (link).

required to operate beyond planned retirement dates to address temporary adequacy shortfalls. In addition, the location of new generation capacity could be different than existing asset locations, which adds pressure to accompanying grid buildout challenges and operations. The resource adequacy and operating reliability impacts of such a scenario are worth exploring.

3.2. General

Section Summary: Differences between the treatment of new and existing sources in the rules can capture variation in mitigation costs between these resources, but the more stringent requirements on newer, more efficient capacity may provide incentives to shift generation to existing capacity with higher emissions intensities. In addition, the proposed rules may not offer sufficient incentive to keep existing nuclear plants online after IRA and U.S. Infrastructure Investment and Jobs Act (IIJA) credits expire, which may offset some of the emissions reductions from the rules. Finally, accounting for impacts from flexible plant operations may alter system investments, operations, and emissions, including design decisions related to the proposed rules.

The approach to new and existing gas generation in the rules should account for differences in mitigation cost between these sources. The more stringent requirements on newer, more-efficient capacity may provide incentives to shift generation to existing NGCC and simple-cycle units with higher emissions intensities for CO_2 and criteria pollutants.

The subcategorization for new and existing sources may lead to emissions-intensive units running up to their capacity factor thresholds, given the functional role of firm capacity in addressing resource adequacy concerns as units retire. Even if this approach lowers CO_2 emissions relative to a counterfactual without the rules, it could leave lower-cost near-term reductions on the table and increase non-CO_2 pollution, which has environmental justice implications that are not explicitly accounted for in the Regulatory Impact Analysis (RIA).[100]

The rules should account for impacts from flexible plant operations—in which units alter their output in response to market conditions—that can alter system investments, operations, and emissions, including design decisions related to the proposed rules.

System changes from retirements of existing coal- and gas-fired power plants, additions of variable renewables such as wind and solar power, and changes in load profiles from electrification—changes that are underway but may be amplified by IRA incentives and proposed performance standards—may alter the operational profile of the remaining dispatchable generation fleet.[101] Engaging in these types of flexible operations more frequently may lead to accelerated degradation, impacts on efficiency, and reductions in plant reliability. For instance, EPRI research illustrates the extent of efficiency losses associated with load following and identifies portions of the plant that are impacted most by decreased load stability.[102] Such operational regimes and their contributions toward lowering total CO_2 and integrating renewables may mean that emissions intensities (in mass of emissions per MWh of electricity

[100] Bushnell and Wolfram (2012). Enforcement of Vintage Differentiated Regulations: The Case of New Source Review. Journal of Environmental Economics and Management, 64(2): 137–152 (link).
[101] Bistline (2017). Economic and Technical Challenges of Flexible Operations under Large-Scale Variable Renewable Deployment. Energy Economics, 64: 363–372 (link).
[102] EPRI (2011). *Cycling and Load-Following Effects on Heat Rate*. EPRI Report 1022061 (link).

generated) may increase even while total emissions fall. These factors may also impact assessments of resource adequacy and operational reliability (Section 3.2).

Based on EPRI modeling, batteries and other energy storage options could be partially substitutable for intermediate and peaking gas capacity. The role of firm capacity for seasonal supply-demand imbalances should also be considered.

EPA is interested in "comments as to whether improvements in energy storage will reduce reliance on intermediate and peaking turbines" (Rules, p. 494). Lower costs of solar increase battery storage deployment, and although this reduces natural-gas-fired generation, capacity changes are much smaller, given the value of these resources in helping to address seasonal supply-demand imbalances. A recent analysis in *Nature Communications* on the value of storage quantifies this at different cost points.[103] In the analysis, natural gas capacity without CCS ranges from 458 GW to 482 GW under net-zero electric sector CO_2 scenarios, while CCS-equipped gas decreases from 417 TWh/yr to 97 TWh/yr with lower renewables costs and higher battery storage deployment.

[103] Bistline and Young (2022). The Role of Natural Gas in Reaching Net-Zero Emissions in the Electric Sector. Nature Communications, 13: 4743 (link).

4. State Plans and Trading

Section Summary: Flexibility and trading can achieve equivalent emissions reductions at lower cost or greater emissions reductions for the same cost, which may be valuable where there is heterogeneity across sources and abatement costs. Banking, averaging (across units and time), and intrastate state can lower costs while achieving equivalent emissions reductions. EPRI research indicates that such flexibility can lower system costs and provide operational flexibility.[104]

The proposed rule indicates that it will "allow states to include trading or averaging in state plans so long as they demonstrate equivalent emissions reductions" (Rules, p. 24). EPA also agrees that "Emission trading can allow the owners and operators of EGUs to prioritize emission reduction actions where they are the quickest or cheapest to achieve while still meeting electricity demand and broader environmental and economic performance goals" (Rules, p. 580). Technical and economic limitations associated with deploying and scaling emerging technologies such as CCS and hydrogen (Sections 2.2 and 2.3, respectively) increase the value of flexibility and optionality to balance affordability, reliability, and emissions reductions.

Flexibility for states to choose either rate- or mass-based trading can provide option value by tailoring plans to specific regional circumstances.

Flexibility can help facilitate affordable, reliable, and clean power systems, especially as conditions change. Rate-based approaches could make sense in contexts with high degrees of expected load growth from electrification, population growth, and new loads (for example, hydrogen production, data centers, direct air capture, and cryptocurrency mining).

Mass-based approaches can enable operational and compliance flexibility and can leverage emissions reductions from lower capacity factors, allowing capacity to maintain operational flexibility and address local system reliability concerns.[105] Although there is familiarity with mass-based programs in the past for CO_2 and criteria pollutants, past experience indicates that "emission budgets have often been overestimated when set many years in advance of the start of a program, as economic and technological conditions have changed significantly between the time the program was adopted and when compliance obligations begin" (Rules, p. 586). However, dynamic budgeting could reduce incentives to retire units or reduce utilization. Subcategory definitions provide some crediting for retirements and reduced capacity factors, but there are outstanding questions about whether eligibility details provide adequate incentive for these potentially lower-abatement-cost actions without creating incentives that may leave cost-effective emissions reductions on the table.

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[104] EPRI (2023). *Power Plant Performance Standards and Tax Credit Interactions: Impacts of Design Decisions and the Inflation Reduction Act on the U.S. Power Sector*. EPRI Report 3002026291 (link).
Bistline et al. (2020). Electric Sector Impacts of Renewable Policy Coordination: A Multi-Model Study of the North American Energy System. Energy Policy, 145: 111707 (link).
Bistline, Santen, and Young (2019). The Economic Geography of Variable Renewable Energy and Impacts of Trade Formulations for Renewable Mandates. Renewable and Sustainable Energy Reviews, 106: 79–96 (link).
Bistline and de la Chesnaye (2017). Banking on Banking: Does "When" Flexibility Mask the Costs of Stringent Climate Policy? Climatic Change, 144(4): 597–610 (link).

[105] EPRI (2017). *Understanding Clean Power Plan Choices in Kansas: Options and Uncertainties*. EPRI Report 3002009492 (link).

Rate-based compliance instruments should be denominated in generation terms (for example, MWh) as well as those in emissions terms (for example, tons).

EPA states, "A compliance instrument denominated in MWh that is awarded to one affected EGU may not represent an equivalent amount of emissions credit when used by another affected EGU to demonstrate compliance, as the CO_2 emission rates (lb. CO_2/MWh) of the two affected EGUs are likely to differ." However, instruments denominated in MWh could be scaled by their emissions intensity relative to the rate target when these credits are issued. For instance, a market balance equation for emissions reduction credits in a state with generation-based instruments could look like:

$$\sum_{u}(1-\frac{\varepsilon_u}{\sigma})X_u \geq 0$$

where ε_u is the emissions rate for unit u (in pounds CO_2 per megawatt-hour, or similar terms), σ is the performance standard for the applicable subcategory, and X_u is the annual emissions of unit u. Here, emissions rate credits would be issued to units that are lower than the standard ($\varepsilon_u < \sigma$), and awarded credits would be $(1-\frac{\varepsilon_u}{\sigma})X_u$. Compliance instruments are therefore denominated in generation terms, but issued credits are effectively scaled by the term $(1-\frac{\varepsilon_u}{\sigma})$, which varies based on the emissions rate of the affected EGU. Likewise, for units with emissions rates that exceed the standard ($\varepsilon_u > \sigma$) and would need to purchase credits to operate, the number of credits that the unit would need to surrender would again be scaled by the unit's CO_2 intensity relative to the standard $(1-\frac{\varepsilon_u}{\sigma})X_u$.

Adopting compliance instruments in emissions terms complicates crediting of zero-emission resources for states wishing to use generation shifting for compliance in their state plans. The approach is straightforward when instruments are denominated in generation terms, but would require separate translation into emissions-based terms. Such retirements and lower utilization are common, cost-effective mitigation options in energy system decarbonization studies.[106]

Temporal flexibility should be considered as an element of state plans, including banking of tradeable compliance instruments.

Temporal flexibility (often called "when" flexibility) can be used as a cost-containment mechanism, which allows aggregate pollution targets to be met by varying the time path of mitigation. Banking can reach emissions goals at lower cost, incentivize early action, promote market liquidity, and give flexibility in planning and operations.[107]

This flexibility can shift compliance obligations by regulated entities either earlier (through banking) or later (through borrowing) in the time horizon to take advantage of perceived intertemporal arbitrage opportunities. In particular, banking is attractive when expectations of higher marginal abatement costs in the future outweigh discounting and capital stock effects, which encourage earlier abatement efforts when costs are comparably low.

[106] Bistline et al. (2022). Actions for Reducing U.S. Emissions at Least 50% by 2030. Science, 376(6596): 922–924 (link).
[107] Bistline and de la Chesnaye (2017). Banking on Banking: Does "When" Flexibility Mask the Costs of Stringent Climate Policy? Climatic Change, 144(4): 597–610 (link).

5. Regulatory Impact Analysis

5.1. IPM Modeling

Section Summary: Modeling of the rules in the RIA with the Integrated Planning Model (IPM) has omissions, simplifications, and assumptions that, taken together, likely mean that the RIA underestimates the incremental emissions reductions of the rules, compliance costs, and benefits, as well as their associated uncertainty. Key limitations include:

- Modeling of the standards for existing gas units and Phase III of the new source standards outside of the IPM model, which likely understates compliance costs and other impacts.[108]
- Temporal resolution of IPM systematically underestimates the need for firm capacity and overestimates the availability of variable resources, which can imply that compliance costs are understated in scenarios with high renewable deployment.
- Modeling fixes nuclear plant retirement dates and does not allow for early retirements based on economic decision making, even as the analysis projects lower future power prices—overstating emissions reductions in the baseline scenario and understating emissions reductions because of the proposed rules.
- No representation of upstream hydrogen production or its associated emissions, electricity demand, or infrastructure.
- Optimistic hydrogen price and availability assumptions may overstate its contribution to the proposed rules and understate compliance costs and regional variability.
- Load growth assumptions are low relative to the published literature and exclude impacts of demand from electrolysis, likely resulting in systematic understatement of compliance costs.

We review each of these issues next.

Modeling of the proposed rules should include the standards for existing gas and Phase III of the new source standards. Omitting these aspects of the rules likely understates compliance costs and their associated impacts.

Modeling of the proposed rules with IPM in the RIA incorporates only existing performance standards for coal-fired power plants and a portion of the new source performance standards (NSPS). IPM modeling does not represent standards for existing gas or Phase III of the new source standards. Although the proposed 111(d) rules for existing gas units are addressed in a spreadsheet analysis, this spreadsheet analysis is based on heuristics (for example, the reduced generation from existing NGCC units affected by the rules is offset by low-carbon resources [20%] and other NGCC units [80%]) but should include consideration of how relative costs of compliance options would drive decisions. Further, EPA should consider hydrogen cofiring as a compliance option for affected NGCC units in the modeling rather than including only CCS retrofits.

[108] Although a July 7, 2023 memo from EPA includes analysis of the integrated proposal in IPM, most of the analysis in the RIA was not updated accordingly. EPA (2023). Integrated Proposal Modeling and Updated Baseline Analysis. Memo to the Docket, released July 7, 2023 (link).

A more expanded modeling analysis using IPM should consider compliance pathways for existing NGCC units. Previous EPRI research[109] indicates that the total emissions reductions from combining policies may be less than the sum of the individual policies. Given the current analysis in the RIA, interactions between the proposed rules are ignored, potentially overstating possible emissions reductions. As part of the effort in modeling compliance pathways for existing NGCC units, IPM should be updated to include hydrogen cofiring retrofit options for these units.

Since the proposed rules were published, EPA has conducted additional analysis using IPM to evaluate the impacts of an integrated proposal, which was released via a memo to the docket.[110] This memo presents IPM results for several scenarios, including an integrated proposal that considers all components of the proposed rules together. The modeling also has been updated to include hydrogen cofiring retrofit options for existing units. However, these scenarios have not been used to update other sections of the RIA, including the air quality modeling, benefits, and net benefits analysis.

The approach to model power sector impacts of the rules on investments, costs, and emissions should provide more realistic representations of power systems and market dynamics and consider variability of load and renewable resources.

The IPM model's temporal resolution and method for intra-annual segment selection likely undervalues dispatchable capacity, energy storage, and other balancing resources.[111] This structural assumption potentially overstates renewables deployment and coal retirements from IRA and potentially understates firm capacity and energy storage deployment.

IPM's approach to capturing power system operations—and consequently their impacts on investments and retirements—uses a load duration curve-based approach, where a discrete number of daily and seasonal periods are selected to represent variations in load, instead of including all 8,760 hours. The modeling uses "24 load segments in its seasonal [load duration curves]" in v6 of IPM that represent four time-of-day categories and six demand levels.[112] Wind and solar capacity factors for those segments are then assigned to each period based on the average resource availability during the corresponding load period.[113] This "seasonal average" approach may capture load duration curves relatively well, but such methods do not represent variability of renewable resources very well. As shown in Figure 26, seasonal average approaches omit maximum and minimum availability periods. This problem is not necessarily solved with more segments, because the method of segment selection is critical to accurately represent the joint distribution of time-series variables, such as load and potential renewable output.[114] Furthermore, seasonal average approaches also do not accurately represent the distribution and co-variation of load and

[109] EPRI (2023). *Power Plant Performance Standards and Tax Credit Interactions: Impacts of Design Decisions and the Inflation Reduction Act on the U.S. Power Sector*. EPRI Report 3002026291 (link).
[110] EPA (2023). Integrated Proposal Modeling and Updated Baseline Analysis. Memo to the Docket, released July 7, 2023 (link).
[111] Bistline (2021). The Importance of Temporal Resolution in Modeling Deep Decarbonization of the Electric Power Sector. Environmental Research Letters, 16(8): 084005 (link).
Bistline et al. (2021). Modeling Variable Renewable Energy and Storage in the Power Sector. Energy Policy, 156: 112424 (link).
Blanford et al. (2018). Simulating Annual Variation in Load, Wind, and Solar by Representative Hour Selection. The Energy Journal, 39(3): 189–212 (link).
[112] Section 2.3.5 of the "Documentation for Post-IRA 2022 Reference Case" available here.
[113] The documentation mentions, "To obtain the seasonal generation for the units in a particular resource class in a specific region, the installed capacity is multiplied by the number of hours in the season and the seasonal capacity factor" (Section 5.3.2).
[114] Bistline (2021). The Importance of Temporal Resolution in Modeling Deep Decarbonization of the Electric Power Sector. Environmental Research Letters, 16(8): 084005 (link).

potential wind and solar output, which is important for accurately characterizing the economics of variable renewables, the value of dispatchable capacity, and economics of energy storage technologies.

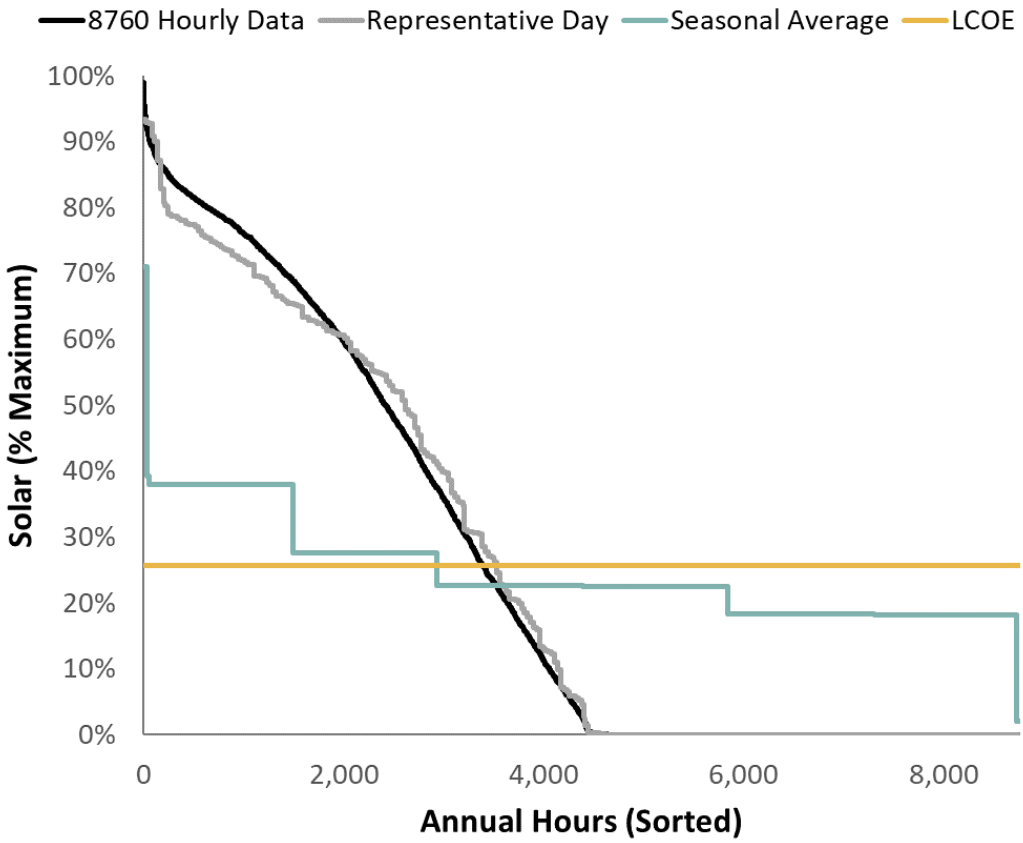


Figure 26. Annual duration curves for solar output in California. The hourly duration curve (black) shows the full data and is compared with several temporal aggregation approaches, including a seasonal average approach similar to that of IPM. Duration curves show values sorted in descending order and weighted by segment length. Values are shown for 2015 meteorology.[115]

Potential impacts of this simplification can be evaluated using residual load duration curves, which are calculated as demand minus available renewables output and represent load that must be met with dispatchable resources. Figure 26 shows residual load in California with 60 GW solar (that is, approximately peak load in 2015), sorted from low to high. The hourly values illustrate how solar has a limited capacity contribution and provides energy disproportionately at hours with low residual load. These characteristics contribute to declining marginal returns for increasing variable renewable deployment, which has been observed in actual markets and modeling studies.[116] However, the seasonal approach leads to contributions of solar to the peak being too high and to low-load hours being too low for the higher solar penetration case, which underestimates peak capacity needs and curtailments.

[115] Bistline (2021). The Importance of Temporal Resolution in Modeling Deep Decarbonization of the Electric Power Sector. Environmental Research Letters, 16(8): 084005 (link).
[116] See "A Primer on Wind and Solar Value Deflation" for more information.

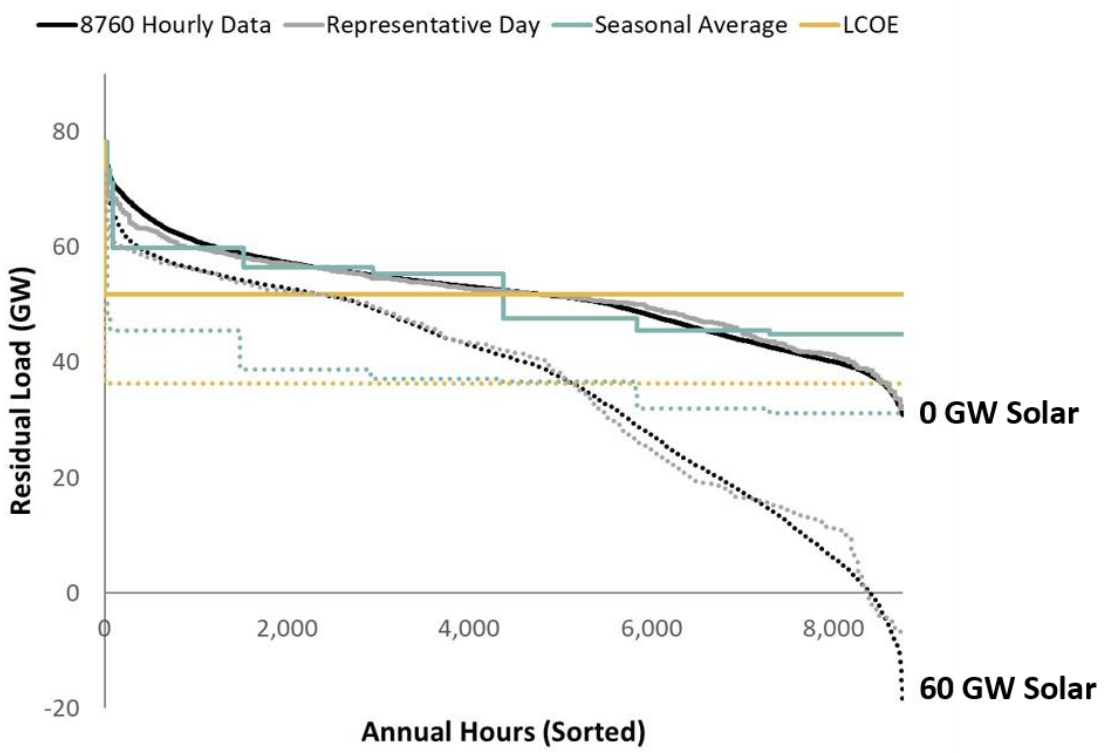


Figure 27. Residual load duration curve for California with 0 GW solar (solid) and 60 GW solar (dotted). The hourly duration curve (black) is aggregated using several approaches, including a seasonal average approach similar to that of IPM.[117]

Based on the experiments in a recent paper in Environmental Research Letters[118], the simplifications around IPM's temporal resolution could lead to the analysis in the RIA overstating wind and solar deployment in the baseline scenario, while understating firm capacity and energy storage.

A related limitation of IPM is that it does not represent unit commitment and dispatch in a detailed manner. Dispatch is based on variable generation costs alone and does not include operational constraints (for example, ramp rates, startup and shutdown costs, and minimum load limits). For example, turndown constraints are used instead to prevent peaking behavior in some units (for example, coal). Prior work[119] has shown that these constraints—which only approximate unit commitment and dispatch decisions—may limit the use of these units, supporting their early economic retirement within the modeling framework. Including a more detailed parameterization of thermal fleet flexibility can provide better representations of the potential role of these plants, especially with higher renewables penetration.[120]

[117] Bistline (2021). The Importance of Temporal Resolution in Modeling Deep Decarbonization of the Electric Power Sector. Environmental Research Letters, 16(8): 084005 (link).
[118] Bistline (2021). The Importance of Temporal Resolution in Modeling Deep Decarbonization of the Electric Power Sector. Environmental Research Letters, 16(8): 084005 (link).
[119] Mallapragada et al. (2018). Impact of Model Resolution on Scenario Outcomes for Electricity Sector System Expansion. Energy, 163: 1231–1244 (link).
[120] For a recent literature review, see Emmanuel et al. (2020). A Review of Power System Planning and Operational Models for Flexibility Assessment in High Solar Energy Penetration Scenarios. Solar Energy, 210: 169–180 (link).

The modeling does not account for the possibility of early nuclear power plant retirements, which may offset some of the emissions reductions from the rules. This omission may influence modeled investments, generation, emissions, and costs associated with the rules and may underestimate the value of design elements in the rules or other associated policies that may mitigate these retirements.

The documentation of v6 of IPM[121] indicates that "endogenous retirements of nuclear units are not allowed. Nuclear units are retired per a predetermined retirement schedule." This assumption means that 92 GW of nuclear capacity is online by 2030 in IPM modeling and nearly 80 GW is still online by 2040 both in the reference scenario with current policies and in the modeled 111 scenario. This fixed retirement schedule for existing nuclear plants means that retirements do not respond to economic incentives that could change under different policy conditions, assumptions about natural gas prices, and other factors. Prior research by EPRI and others indicates that endogenously capturing power plant retirements is critical for understanding potential power sector investments, retirements, generation, emissions, and costs.[122] In particular, the omission of endogenous retirements could:

- Understate potential retirement risks for existing nuclear power plants
- Underestimate capacity needs of future regional power systems, which also would alter modeled impacts from the proposed NSPS and ESPS
- Alter modeled system costs and electricity prices

Endogenous power plant retirements are especially important to consider, given how IRA's production-based tax credits may put downward pressure on wholesale electricity prices, which alters the economic incentives for firm entry and exit—especially for existing capacity.[123] However, the existing nuclear production credit in IRA is set to expire in 2032, while production and investment tax credits potentially continue for a decade or more afterward.[124] Without additional policy support, these dynamics can increase retirement risks for nuclear generation, especially if new and existing source rules further increase the deployment of incentivized resources.

The modeling should include hydrogen supply explicitly and represent uncertainty in future costs and availability of hydrogen. The current assumptions likely overestimate hydrogen availability and underestimate its costs.

Based on results from IPM presented in the RIA (Table 3-10, p. 3-22), U.S. low-carbon hydrogen demand from the electric sector is expected to increase to nearly 350 trillion Btu by 2040 because of the proposed rules (Figure 28). This hydrogen demand for 111 compliance represents a projected increase of 30% over U.S. hydrogen production today,[125] nearly all of which is derived from natural gas steam methane reforming. In subsequent IPM scenarios released via memo,[126] electric sector hydrogen demand is

[121] Section 4.6.1 of the "Documentation for Post-IRA 2022 Reference Case" available here.
[122] EPRI (2022). *Nuclear Energy in Long-Term System Models: A Multi-Model Perspective*. EPRI Report 3002023697 (link).
[123] Bistline, Mehrotra, and Wolfram (2023). Economic Implications of the Climate Provisions of the Inflation Reduction Act. NBER Working Paper 31267 (link).
[124] Bistline et al. (2023). Emissions and Energy Impacts of the Inflation Reduction Act. Science, 380(6652): 1324–1327 (link).
[125] U.S. DOE Hydrogen and Fuel Cell Technologies Office, Hydrogen Production (link).
[126] In the "Integrated Proposal" and "Integrated Proposal with LNG" (liquified natural gas) scenarios: EPA (2023). Integrated Proposal Modeling and Updated Baseline Analysis. Memo to the Docket, released July 7, 2023 (link).

expected to increase even further (Figure 28), peaking at nearly 770 trillion Btu in 2035 (in the integrated proposal with LNG updates scenario), representing over two-thirds of today's hydrogen production.

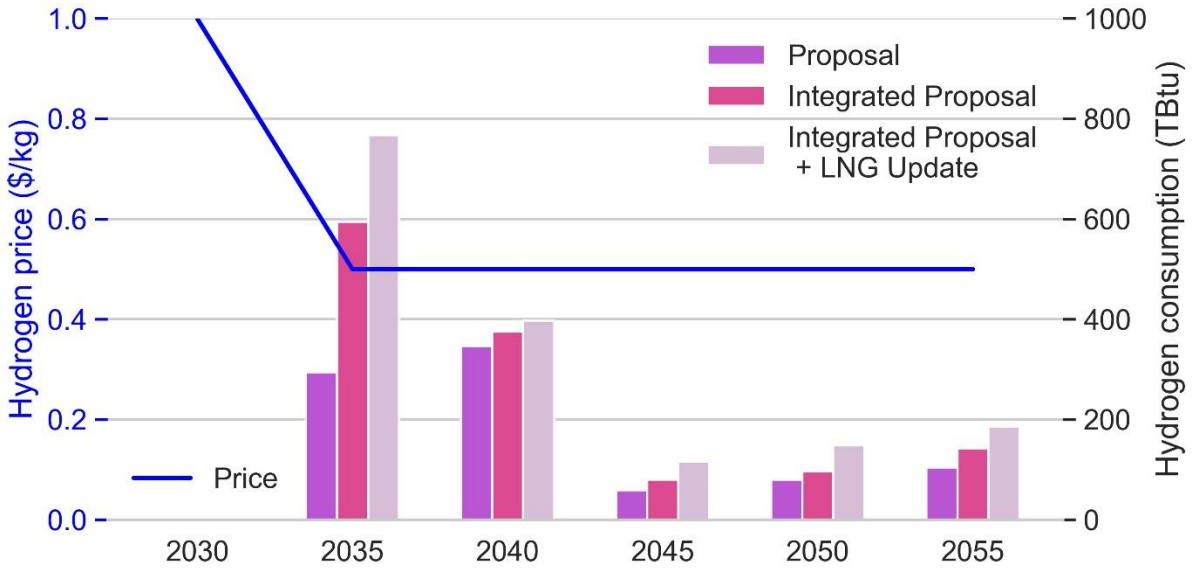


Figure 28. Hydrogen consumption and prices over time across scenarios in the IPM modeling of the proposed rules (including the updated proposal scenarios). Developed based on data in the RIA and supporting information.

The methodology for modeling power system impacts omits an explicit representation of low-carbon hydrogen production and delivery, which may overstate its contribution to achieving cost-effective emissions reductions via the proposed rules. As described in detail in Section 2.3, the low assumed price of hydrogen, combined with other simplifications noted in this section, likely implies that IPM results underestimate costs and overestimate the technical feasibility of hydrogen-related pathways.

The rules and RIA assume that DOE's Hydrogen Shot goal of $1 per kilogram of low-GHG hydrogen is met by 2030 and assume $0.5/kg-$H_2$ costs in all regions in perpetuity beginning in 2035 (Figure 28). In addition, IPM does not track electrolytic hydrogen production or time-matched electricity supply and its associated emissions. Without those representations or hydrogen storage balance equations, the RIA analysis likely overestimates hydrogen availability and underestimates its costs and emissions.

IPM's representation of hydrogen should be strengthened to include a more detailed representation of hydrogen supply, consistent with how other fuels are represented endogenously. This may include modeling the resource potential and costs of electrolysis, hydrogen transport, and storage. Research by EPRI and others indicates that detailed modeling is required to accurately characterize hydrogen economics,[127] including the impacts of recent IRA incentives that depend on the emissions intensity of upstream hydrogen production.

[127] EPRI (2022). *Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis*. EPRI Report 3002024882 (link).

On page 95 of the RIA, EPA explains that compliance costs are lower in the more stringent scenario because the hydrogen price—represented exogenously as $1/kg under the baseline and $0.5/kg in years when the second phase of the proposed NSPS is assumed to be active—decreases in 2030 rather than in 2035, as in the proposed and less stringent scenarios. The price reduction timeline is modeled as a function of the implementation schedule because the second phase of the proposed NSPS is assumed to provide investment certainty to produce hydrogen for use in power sector applications, resulting in lower realized costs. EPRI suggests that this approach to forecasting hydrogen price decline could overrepresent the electrolyzer industry's ability to rapidly scale up to meet increased demand and achieve economies of scale, resulting in counterintuitive and potentially misleading results in the scenario comparisons, as discussed in Section 2.3. A similar approach is used in the integrated proposal modeling and updated baseline analysis released via memo after the proposed rules.

The modeling should consider upstream GHG emissions from producing hydrogen used in the electric sector. The current approach may overestimate emissions reductions from the proposed rules.

The modeling implicitly assumes that hydrogen available to the electric sector will have a life-cycle emissions intensity that is less than 0.45 kg CO_2e/kg hydrogen. However, these upstream emissions are omitted when estimating potential emissions reductions because of the proposed rules. Based on results from IPM presented in the RIA (Table 3-10, p. 3-22), hydrogen demand from the electric sector is expected to increase to nearly 350 trillion Btu by 2040. This additional hydrogen demand may increase GHG emissions by up to 1.2 MMT CO_2e/year, which represents 5% of IPM projected emissions reductions (24 MMT CO_2/year) because of the proposed rules in 2040 (Table 3-19, p. 3-15). In additional IPM scenarios released that consider the integrated proposal with LNG updates,[128] hydrogen demand peaks at nearly 770 TBtu, which could increase emissions by 2.7 MMT CO_2e/year. EPRI suggests including a representation of these emissions in the IPM analysis, which may impact mitigation opportunities and alter the climate and net benefits of the proposed rules.

The modeling should account for the electricity needed to produce the electrolytic hydrogen. The current approach likely underestimates the capacity needs and costs associated with hydrogen-intensive compliance pathways.

In addition to the omission of explicit representations of hydrogen production and associated emissions, modeling in the RIA does not include "any incremental electricity demand associated with [hydrogen] production" (RIA, p. 3-13). This simplification underestimates the costs and capacity needs for increased electrolytic hydrogen. For example, the RIA asserts that around 108 TWh of additional electricity (RIA, p. 3-13) will be required to produce 294 TBtu of hydrogen used in 2035 (RIA, Table 3-10, p. 3-22), which is approximately 2% of projected national electricity demand. However, nearly 80% of this hydrogen demand is projected in a single IPM region, Southern California Edison in WECC (Figure 29), as observed from data presented in supplementary IPM output files (Proposal RPE File.xlsx). Hydrogen demand in Southern California Edison can increase electricity demand by nearly 50% within that region, based on data in supplementary IPM output files (Proposal RPE File.xlsx). Although overall demand for hydrogen grows in additional IPM scenarios that consider the integrated proposal, hydrogen demand in Southern California Edison's jurisdiction consistently remains high relative to other model regions.

[128] EPA (2023). Integrated Proposal Modeling and Updated Baseline Analysis. Memo to the Docket, released July 7, 2023 (link).

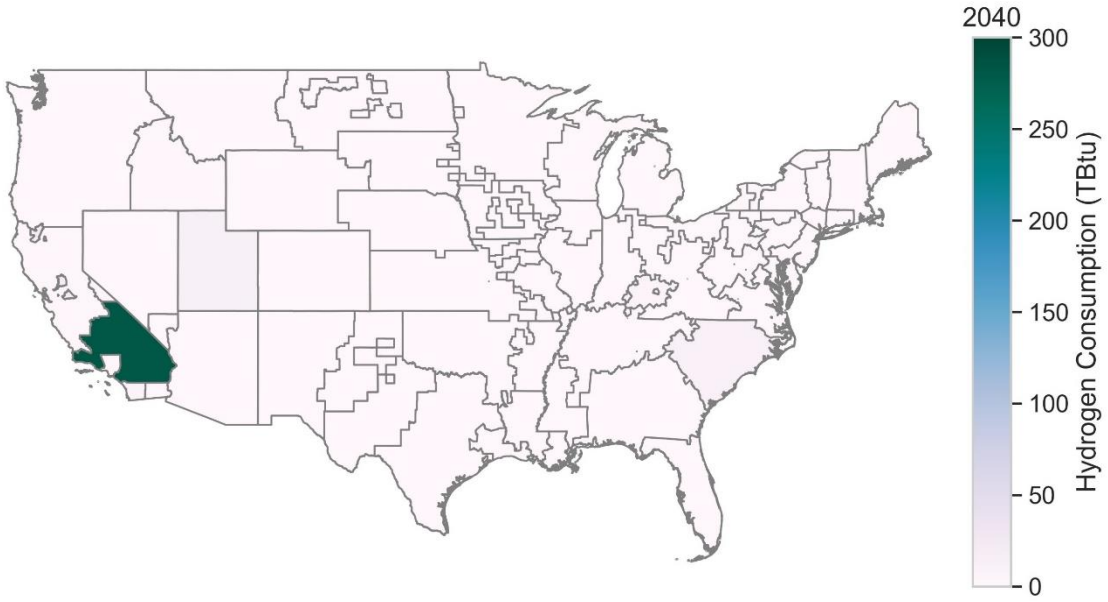


Figure 29. Hydrogen consumption by region in 2040 in the IPM modeling of the proposed rules in the RIA. Results for the integrated proposal scenarios are similar to those presented here. Developed based on data in the RIA and supporting information.

For instance, modeling using EPRI's US-REGEN model assesses alternative technology strategies for achieving economy-wide net-zero CO_2 emissions by 2050.[129] Figure 30 illustrates energy flows in 2050 from a scenario reaching net-zero emissions without geologic CO_2 storage. This assumption restricts the role of the potential scale of negative emissions, which is used in many net-zero CO_2 scenarios,[130] leading to considerable hydrogen demand for fuel synthesis and industry (power sector demand is limited in this scenario), which is nearly 10 times higher than current production levels.[131]

[129] EPRI (2022). *Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis*. EPRI Report 3002024882 (link).
[130] Browning et al. (2023). Net-Zero CO_2 by 2050 Scenarios for the United States in the Energy Modeling Forum 37 Study. Energy and Climate Change, 4: 100104 (link).
[131] Note that, in the "All Options" sensitivity from this study (that is, where negative emissions options are allowed to reach net-zero at least cost), electrolytic hydrogen is not used and hydrogen supply comes from CCS-equipped biomass and gas production.

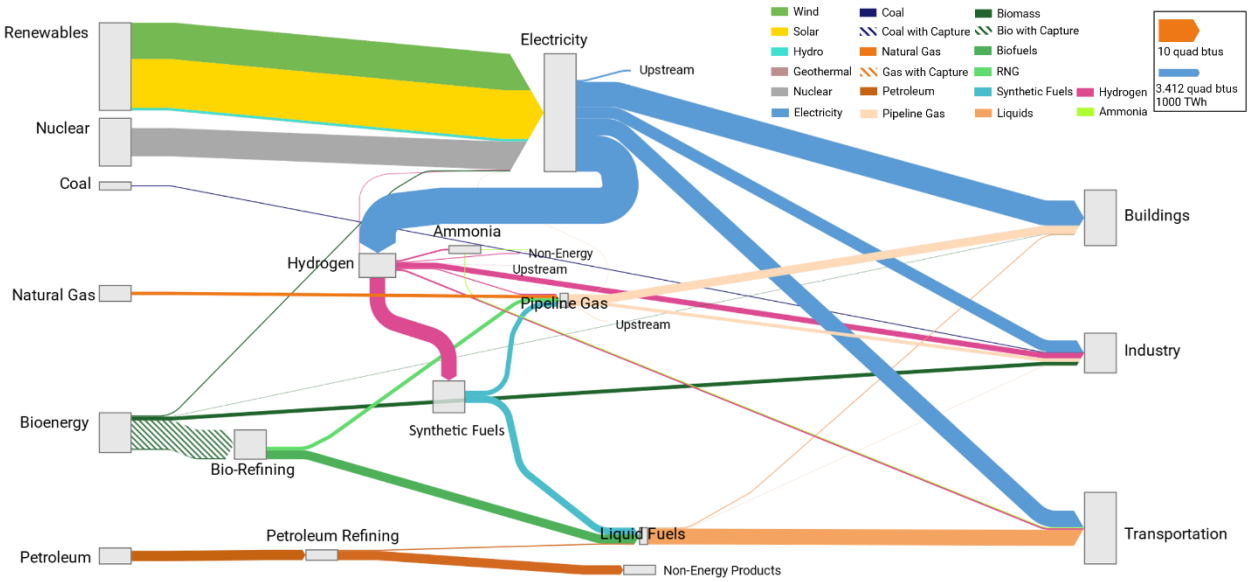


Figure 30. Modeled U.S. primary and final energy in 2050 under an economy-wide net-zero CO_2 emissions scenario. This Sankey diagram is based on US-REGEN modeling and analysis in the "Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis" report[132], specifically the "Limited Options" scenario, which assumes no geologic CO_2 storage.

The assumed price of delivered hydrogen should account for regional variation, including quality of renewable energy resources and availability of storage capacity.

In addition to the lack of regional variation in renewable generation potential and electricity prices as an input to electrolysis (discussed in Section 2.3), the IPM modeling does not appear to account for how much of the country lacks viable geology for economically feasible underground storage of hydrogen, which could further increase the delivered cost of hydrogen fuel to these regions. The Atlantic coastal region, for example, lacks existing natural gas storage infrastructure that could be converted to hydrogen storage, as well as large underground salt formations that could be used to create new storage capacity for hydrogen (Figure 31).[133]

[132] EPRI (2022). *Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis*. EPRI Report 3002024882 (link).
[133] EPRI (2022). *Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis*. EPRI Report 3002024882 (link).

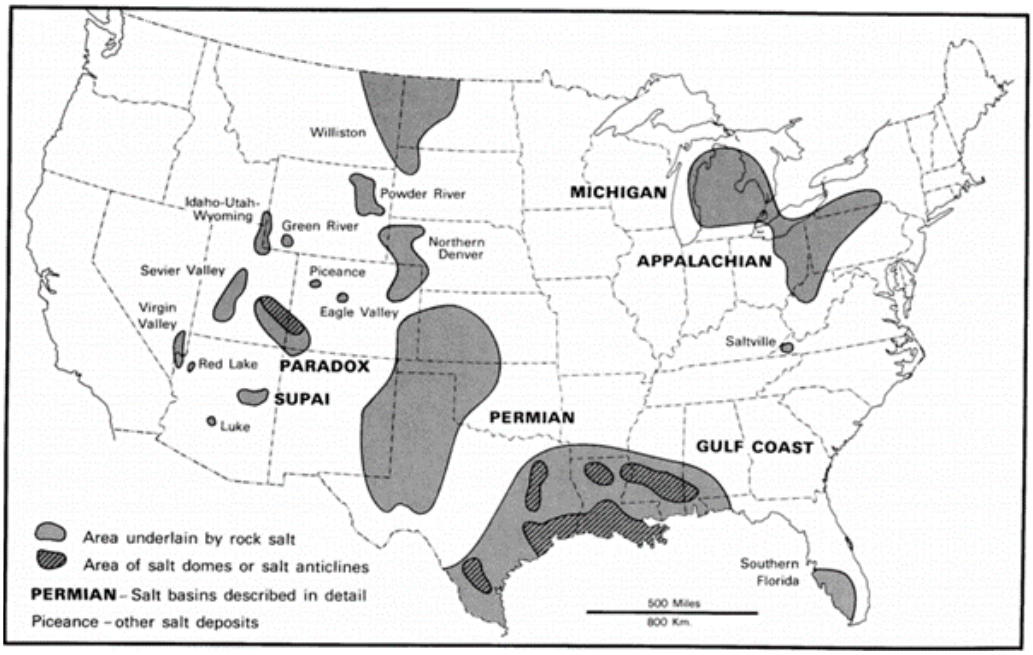


Figure 31. Map of U.S. salt domes and salt beds. Underground salt deposits, especially salt domes, could be solution mined to create new storage capacity for hydrogen.[134,135]

Coal retirement assumptions should align with announced retirements. The current approach likely understates the impacts and costs of the proposed rules.

The baseline scenario (that is, before incorporating the proposed 111 rules) includes extensive coal retirements beyond currently announced levels. Such retirements may be driven in part by the low modeled natural gas prices, which are below $3/MMBtu across the time horizon and around $2/MMBtu beginning in 2035. Installed coal capacity in the baseline scenario in IPM is at the lower end of the recent published literature, as shown in Figure 33. Although recent years have seen extensive coal retirements and announcements of future retirements (Figure 2), retirements in the baseline scenario exceed these announcements by about 50 GW in 2030.

[134] EPRI (2023). *Review of Hydrogen Geologic Storage Options in the U.S.: Existing Facilities and Potential for Future Storage Expansion*. EPRI Report 3002026653 (link).
[135] Johnson and Gonzales (1978). Salt Deposits in the United States and Regional Geologic Characteristics Important for Storage of Radioactive Waste. Y/OWI/SUB-7414/1 (link).

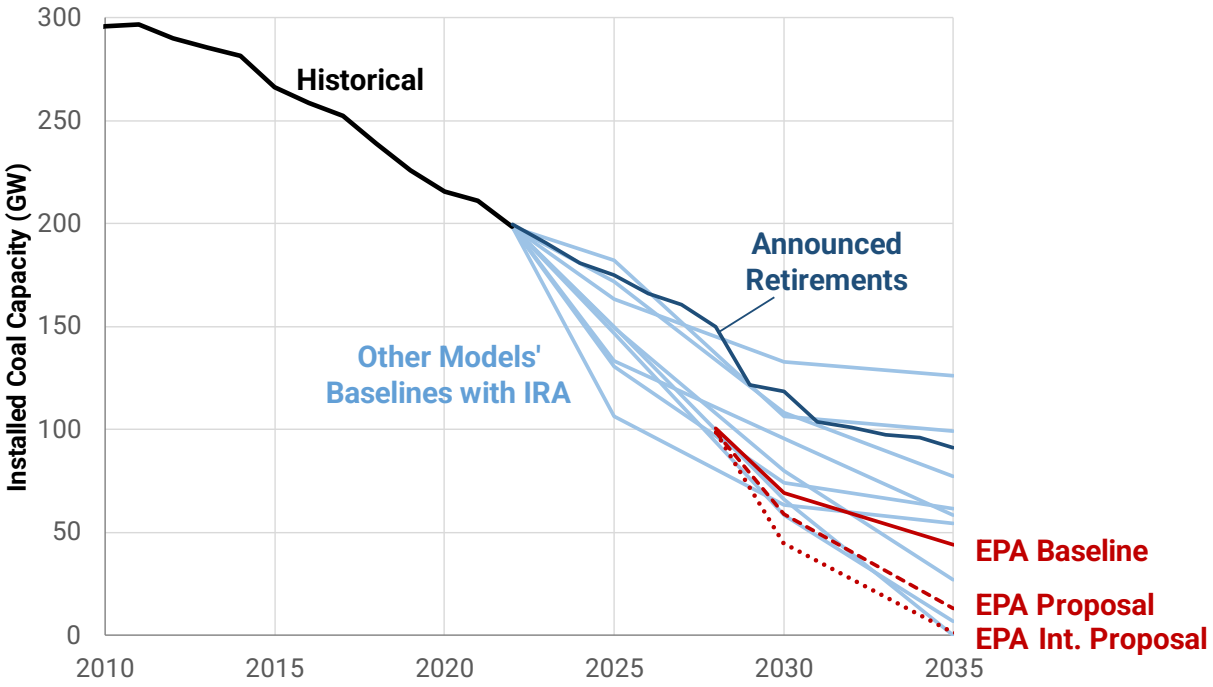


Figure 32. Installed coal capacity over time in the IPM scenarios and baseline values in other models. Values are shown for coal capacity without CCS. Historical capacity is based on EIA-860 data, and announced retirements come from the US-REGEN database, which incorporates announcements from several sources. Baselines in other models include the IRA and come from a recent multi-model study.[136]

With the extensive retirements in the RIA baseline scenario, all else held equal, the modeling likely understates the impacts and costs of the proposed rules. With more coal capacity online, the extent of units subject to 111(d) requirements would be higher, as would baseline emissions.

Modeling power system impacts of the proposed rule should include a broader array of new investment options and retrofits, especially generation options that are relevant to the proposed new and existing source standards.

In particular, the only gas-fired generation option with CCS is an "amine-based, post-combustion CO_2 capture system" with a 90% capture rate (per Section 6.1.1 of the documentation). It also appears that this CCS option reduces the flexibility and ramping capabilities of NGCC capacity, though the documentation could make such assumptions more transparent. Regardless, configurations such as the Allam-Fetvedt Cycle for NGCC with CCS could increase capture rates and alter assumptions about the cost and flexibility of new capacity with CCS, though there is uncertainty about timelines for deploying these technologies, as described in Section 2.2. Such configurations have played roles in decarbonization modeling[137] and projects have been announced through companies such as NET Power.

The modeling should more accurately reflect anticipated end-use electrification trends and their impacts on electricity demand growth, load profiles, and flexible demand.

[136] Bistline et al. (2023). Emissions and Energy Impacts of the Inflation Reduction Act. Science, 380(6652): 1324–1327 (link).
[137] EPRI (2022). *Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis*. EPRI Report 3002024882 (link).

Electricity demand in the IPM modeling is based on the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2021 Reference Case.[138] Regional load shapes are based on observed 2018 data "taken from Federal Energy Regulatory Commission Form 714 data and individual ISOs and RTOs" and are scaled to match the annual AEO 2021 demand.

However, AEO 2021 understates the extent of electrification of transport, buildings, and industry over time. Figure 33 illustrates recent electric vehicle (EV) sales forecasts relative to AEO 2021 levels; 2030 EV sales shares generally range from 20% to 70%, with an average around 50%, while AEO 2021 is just over 6% (similar to 2022 levels). AEO 2021 was also produced before the passage of the IRA, which has generous incentives to accelerate end-use electrification through direct tax credits for electric end-use equipment and indirectly through tax credits that lower electricity prices.[139]

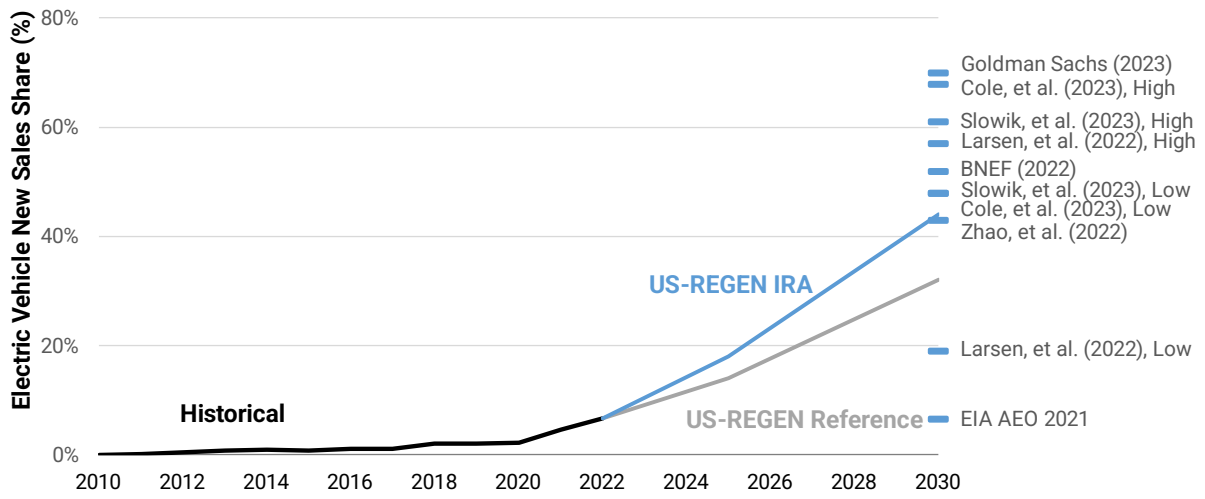


Figure 33. Electric vehicle share of new passenger sales. Electric vehicles include battery electric and plug-in hybrid electric vehicles. Historical values come from the International Energy Agency's "Global EV Outlook 2022." US-REGEN scenarios with and without IRA are compared with recent estimates of electrification shares of new vehicle sales under.[140]

There is uncertainty about the extent of load growth and the relative growth of peak demand, which determines capacity needs. Figure 34 compares electricity's share of final energy in 2050 against electricity demand growth relative to 2015 levels. Although there is variation across U.S. scenarios, varying by model and policy assumption, 2050 electrification and load growth are generally lower for AEO 2021 relative to other scenarios.

[138] Section 3.2 of the "Documentation for Post-IRA 2022 Reference Case" available here. This scenario accounts for incremental electricity demand from EPA's on-the-books passenger vehicle standards, which was not reflected in AEO 2021.
[139] EPRI (2023). *Impacts of Inflationary Drivers and Updated Policies on U.S. Decarbonization and Technology Transitions*. EPRI Report 3002026229 (link).
[140] Bistline, Mehrotra, and Wolfram (2023). Economic Implications of the Climate Provisions of the Inflation Reduction Act. NBER Working Paper 31267 (link).

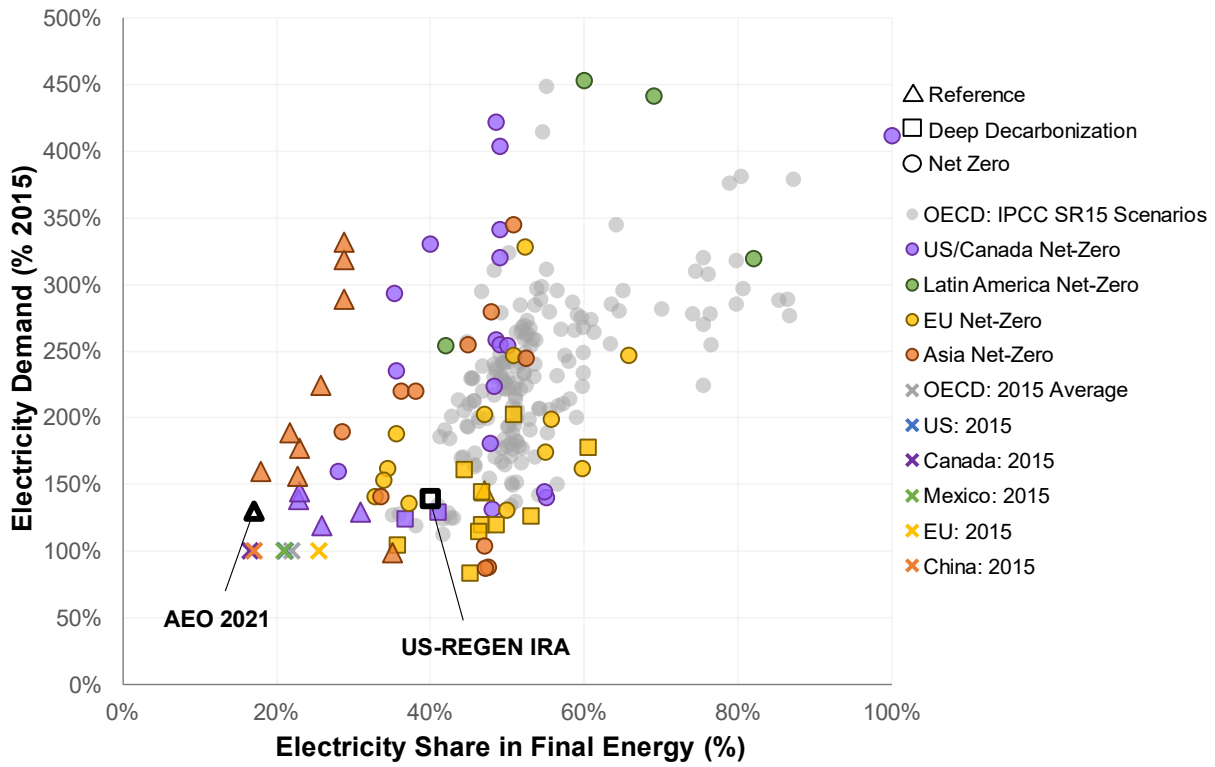


Figure 34. Comparison of electricity share and electricity demand across decarbonization scenarios in 2050.[141]

In addition to aggregate load growth, there is similarly uncertainty about future load shapes from electrification, energy efficiency, and distributed energy resources. Figure 35 illustrates how electrification can alter the distribution of hourly load shapes and suggests that electrification shifts the mean of the distribution and increases variance, especially through space heating in colder climates. There is similar uncertainty about the flexibility associated with load shapes, notably for vehicle charging, and its subsequent impacts on supply-side decisions.

[141] Bistline (2021). Roadmaps to Net-Zero Emissions Systems: Emerging Insights and Modeling Challenges. Joule, 5:2551-2563 (link).

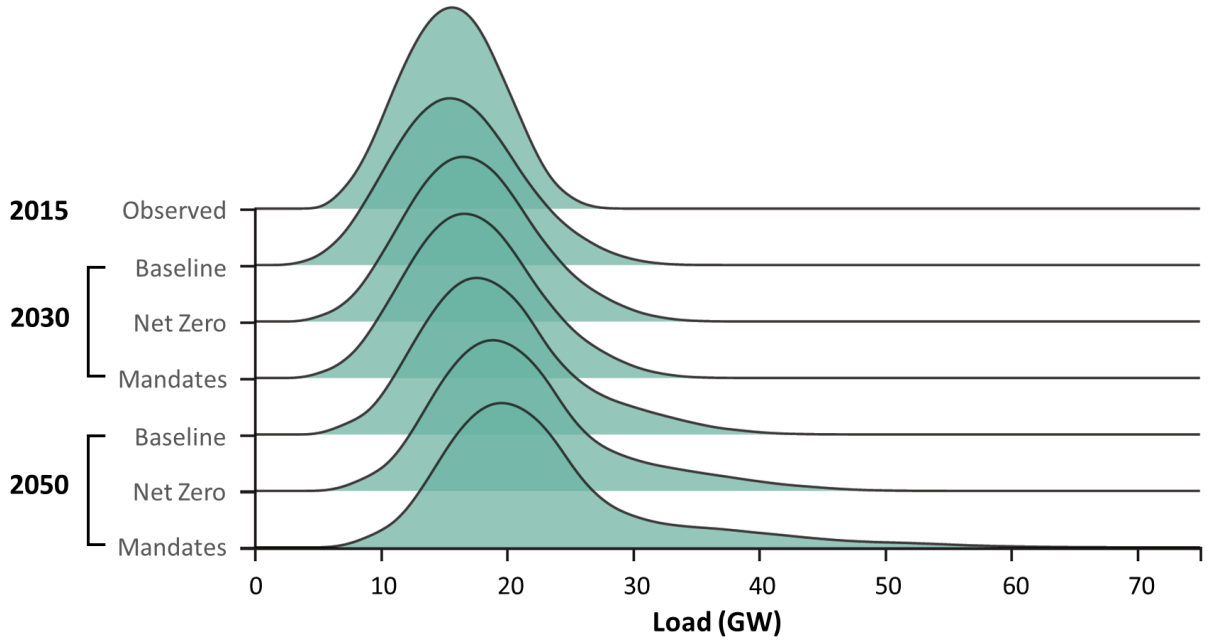


Figure 35. Modeled distribution of hourly loads in Ontario by year and scenario. Values are outputs from the US-REGEN model.[142]

Additional uncertainty and sensitivity analysis should be conducted to account for the numerous policy, technology, and market uncertainties in the planning environment in the coming decades.

Updated guidance from the Office of Management and Budget (OMB) for regulatory analysis (Circular A-4)[143] suggests that uncertainty analysis be performed along with sensitivity analysis that includes plausible alternatives. Scenarios presented in the RIA using IPM (including the post-IRA baseline and the proposed rules) may be supported by a discussion around the main uncertainties in modeling inputs or a quantitative uncertainty analysis because the magnitude of emissions reductions modeled due to the proposed rules may be comparable to the range in possible baseline emissions driven by uncertain modeling inputs. For example, higher natural gas prices may limit the use of large NGCC units to capacity factors lower than the 50% threshold (see Figure 3), both in the baseline and in the proposed rules, impacting possible emissions reductions driven by the proposed rules.

Figure 36 shows the change in CO_2 over time because of the proposed rules in the scenarios presented in the RIA and in the integrated proposal. The baseline scenario without 111 rules entails extensive emissions reductions over time (see the next comment for a more detailed discussion), which makes incremental reductions from 111 rules more limited than a baseline with higher emissions. Uncertainties related to fuel prices, infrastructure expansion, scaling timelines for emerging technologies, inflationary drivers for supply-side technologies, and other drivers could shape baseline emissions trends, as discussed

[142] Bistline et al. (2021). Deep Decarbonization Impacts on Electric Load Shapes and Peak Demand. Environmental Research Letters, 16(9): 094054 (link).
[143] OMB Circular A-4 (link)

in other comments in this section. These unknowns reinforce the importance of additional uncertainty and sensitivity analysis in the RIA to examine cost and emissions impacts of the rules.

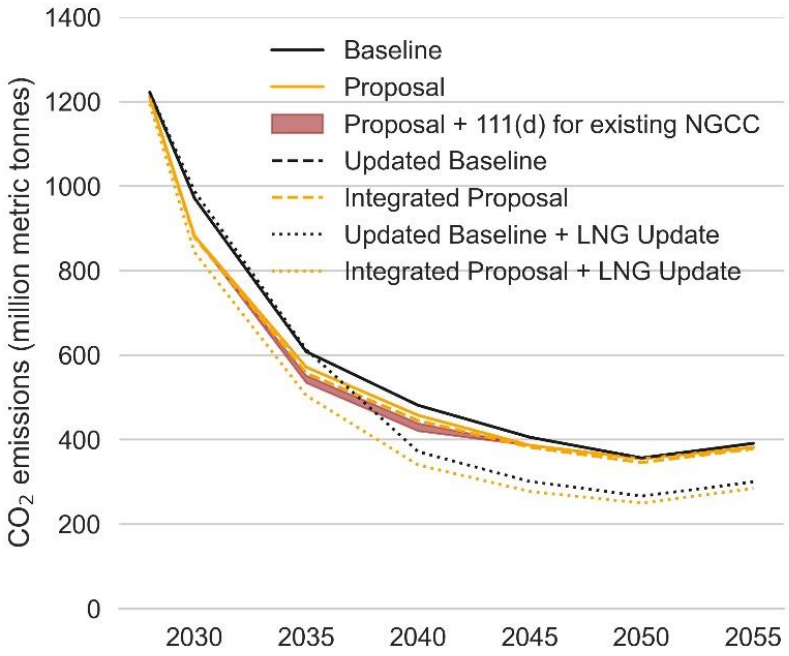


Figure 36. CO_2 emissions for scenarios presented in the RIA and those released subsequently via memo. Developed based on data in the RIA and supporting information.

For example, Figure 36 suggests that an increase in LNG demand, which may result in increased prices of delivered natural gas to the power sector (that is, scenarios that include "+LNG update," based on integrated proposal IPM results released subsequent to the proposed rules[144]), could result in CO_2 emissions that are lower than the scenarios published in the RIA, both in the baseline and for the integrated proposal scenarios. This suggests that natural gas prices may strongly influence the modeled emissions benefits because of the proposed rules.

IRA may have significant effects on power sector and energy system outcomes,[145] but precise impacts from IRA are uncertain and depend on policy and regulatory decisions moving forward—pending U.S. Treasury guidance, uptake of bonus credits, and broader macroeconomic trends. These uncertainties merit side calculations to determine how uncertainty may impact the cost-effectiveness calculations and RIA.

Finally, although modeling in the RIA includes more- and less-stringent scenarios compared to the proposed rules, subsequent modeling that includes the integrated proposal does not consider similar additional scenarios.

[144] EPA (2023). Integrated Proposal Modeling and Updated Baseline Analysis. Memo to the Docket, released July 7, 2023 (link).
[145] Bistline et al. (2023). Emissions and Energy Impacts of the Inflation Reduction Act. Science, 380(6652): 1324–1327 (link).

Long-run CO_2 emissions in the baseline scenario are toward the lower end of recently published literature with IRA.

Although baseline CO_2 emissions in the near term are in line with recently published scenarios with IRA incentives, longer-run emissions are toward the lower end of this recent literature (Figure 37). Lower long-run emissions in the IPM baseline are likely because of higher wind and solar deployment, higher coal retirements, and higher existing nuclear capacity. Several models in Figure 37 exhibit emissions increases after 2032, when modeled existing nuclear retires as a result of expiring IRA and IIJA credits, which the RIA does not explicitly include in its modeling (as discussed in the earlier comment in Section 5.1).

More broadly, the wide range of possible emissions trajectories over time in a baseline scenario highlights the importance of uncertainty and sensitivity analysis.

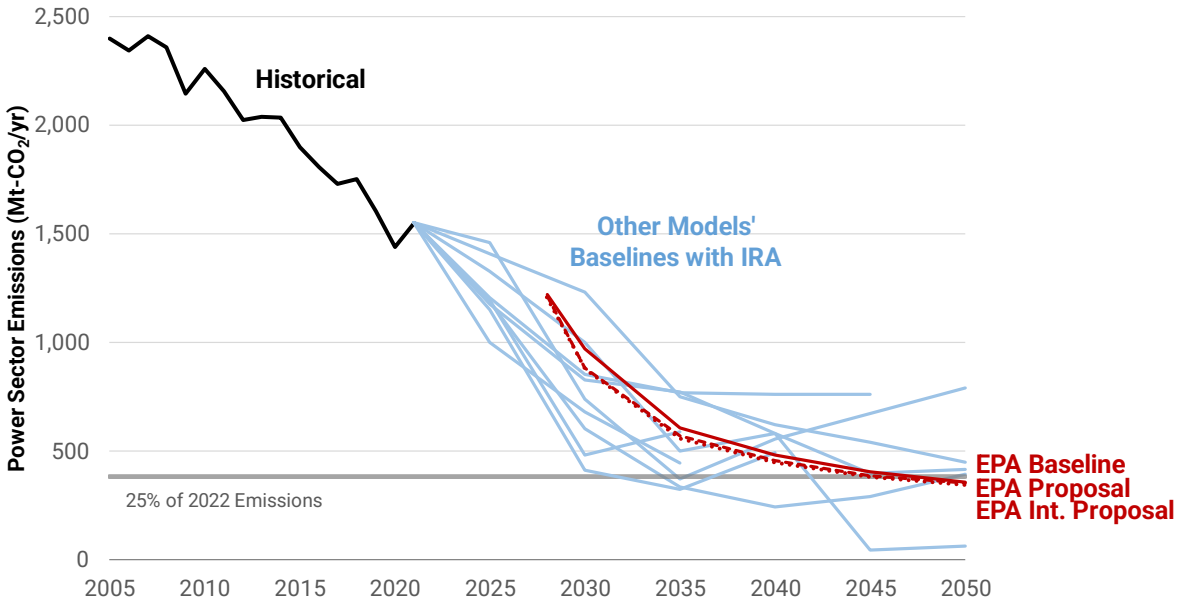


Figure 37. Power sector CO_2 over time in the IPM scenarios and baseline values in other models. Baselines in other models include the IRA and come from a recent multi-model study.[146]

The IPM model should represent technology choices endogenously to ensure the costs and benefits between them are accounted for in calculating the least-cost solution.

According to page 89 of the RIA, the IPM model represents hydrogen cofiring at new gas EGUs exogenously. More comprehensive modeling allowing GHG mitigation strategies for new gas EGUs to be selected based on economic, regional, and other factors would likely produce more robust analyses. EPRI suggests that the modeling be expanded to endogenously determine the impact of mitigation strategies for new gas EGUs.

[146] Bistline et al. (2023). Emissions and Energy Impacts of the Inflation Reduction Act. Science, 380(6652): 1324–1327 (link).

5.2. Air Quality Benefits

Section Summary: EPRI's primary comments on Chapter 4, Benefits Analysis (and the accompanying Technical Support Document [TSD], *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*), are on the limitations of EPA's Environmental Benefits Mapping and Analysis Program (BenMAP), which is used to calculate air quality health benefits in the proposed rules. These limitations include (i) the inclusion of only a subset of published concentration-response functions from a subset of available studies, (ii) limited consideration for uncertainty within its framework, and (iii) no provision for considering different species or components of fine particulate matter ($PM_{2.5}$), despite increasing evidence that some components of $PM_{2.5}$ may be more highly associated with health effects than others. In addition, EPRI has comments on the limited consideration on potential confounding by co-pollutants and the potential air quality impacts related to the use of amine solvents in carbon capture processes. Each of these points is discussed in more detail next.

A broader inclusion of available epidemiological evidence should be considered to provide a more accurate estimate of the number of avoided premature deaths.

EPRI encourages the RIA to consider the impact of the inclusion of only a subset of published concentration-response functions from a subset of available studies in the benefits assessment. The RIA indicates that two studies (Pope III et al., 2019; Wu et al., 2020) were used in the calculation of avoided all-cause mortality given "a number of relative advantages of these studies related to the extended period of observation, the rigorous examination of model forms and effect estimates, the coverage for ecological variables, and the large data set with regard to both population and area" as described in the Health Benefits TSD (p. 30). The RIA also states, "As premature mortality typically constitutes the vast majority of monetized benefits in a $PM_{2.5}$ benefits assessment, quantifying effects using risk estimates reported from multiple long-term exposure studies using different cohorts helps account for uncertainty in the estimated number of PM-related premature deaths." EPRI notes that the two selected concentration-response functions do not adequately capture what is currently available in the literature. EPRI-supported research has highlighted the discrepancy between the published literature and the concentration-response functions used in the RIA's benefits calculations.[147]

In addition, the Medicare population studied by Wu et al. (2020) also has unique demographic characteristics, being disproportionately White, older, and with lower incomes and levels of education compared to the U.S. population.[148] Generalizability of the findings is important to consider in the context of this benefits assessment; additional studies can provide risk estimates that are more relevant for other U.S. populations that would be affected by the proposed rules.

More comprehensive uncertainty assessment should be conducted to account for the multiple variables that collectively affect the estimated benefits.

There are two components of overall uncertainty in benefits calculations: (1) epistemic uncertainty, or lack of knowledge about the true relationship between air pollution and health, and (2) aleatory uncertainty, which reflects essentially statistical uncertainty around the selected epidemiologically based

[147] Smith and Gans (2015). Enhancing the Characterization of Epistemic Uncertainties in $PM_{2.5}$ Risk Analyses. Risk Analysis, 35(3):361–378 (link).
[148] Office of Health Policy (2022). Medicare Beneficiary Enrollment Trends and Demographic Characteristics (link).

concentration-response functions. A National Academy of Sciences (NAS) committee recommended that epistemic uncertainty be integrated into EPA's standard risk analysis approach.[149] However, despite improvements over time, BenMAP does not comprehensively evaluate this type of uncertainty, nor does it have the capability to consider the impacts of simultaneously varying more than one input into BenMAP at a time. The Health Benefits TSD (p. 99) states that a Monte Carlo approach was used to "characterize random sampling error associated with the risk estimates from epidemiological studies." However, the calculated confidence intervals "do not reflect other sources of uncertainty inherent within the estimates, such as baseline incidence rates, populations exposed, and transferability of the effect estimate to diverse locations," providing an incomplete picture about the overall uncertainty.

The RIA should apply a more comprehensive approach to address uncertainty. For several years, EPRI has supported research to develop an integrated uncertainty analysis (IUA) methodology for application to air quality benefits estimation. The IUA approach provides a probabilistic distribution of solutions rather than a single deterministic solution. It can also examine the impact of multiple uncertain variables, each with its own probability distribution, and calculate uncertainties associated with these variables simultaneously. This type of analysis has been recommended by NASEM (2002), noting that health benefits analyses tend to underestimate uncertainties and leave decision-makers with a false sense of confidence in estimates of risk.

A prototype tool was developed, and the methodology underpinning the tool is now under further development, with the goal of sharing via the open scientific literature. The tool taps into BenMAP's demographic database and reads the same air quality grid data. Smith and Glasgow (2018) demonstrated the use of IUA by varying three model inputs—the level of a potential threshold, the slope of the concentration-response function conditional on the level of the threshold, and the error in modeled ozone concentrations.[150] The results of this analysis are shown in Figure 30, extracted from Smith and Glasgow (2018). The mean and median numbers of estimated premature deaths per year in the IUA are approximately 11,000 and 7,000, respectively, while the mean and median for the single, zero-threshold model are approximately 34,000. This example demonstrates that the use of IUA to quantitatively incorporate key model uncertainties into risk estimates produces a substantially altered understanding of the potential public health gain of a given regulatory action.

[149] National Academy of Sciences (2002). Estimating the Public Health Benefits of Proposed Air Pollution Regulations (link).
[150] Smith and Glasgow (2018). Integrated Uncertainty Analysis for Ambient Pollutant Health Risk Assessment: A Case Study of Ozone Mortality Risk. Risk Analysis, 38(1):163–176 (link).

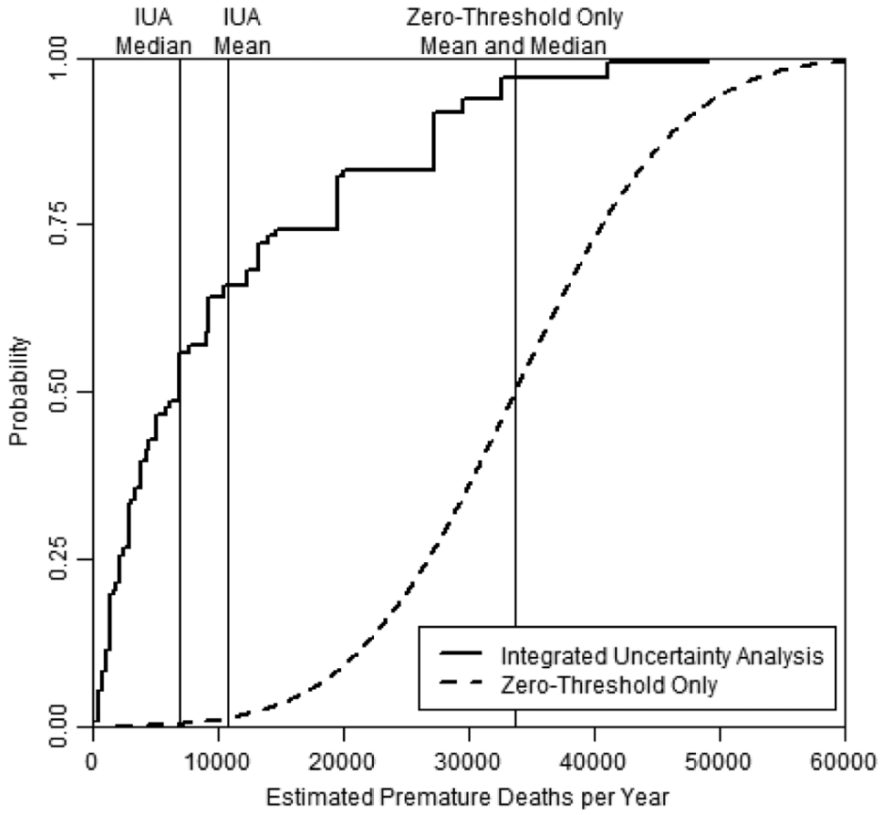


Figure 38. Cumulative distributions estimated for U.S. premature respiratory mortality deaths per year in 2007. Produced by illustrative IUA and single, zero-threshold model approaches, respectively (from Smith and Glasgow, 2018).

Benefits calculations should consider the varying health effects associated with different species/components/sources of $PM_{2.5}$.

The RIA (p. 4-38) states, "We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality." BenMAP offers no provision for considering different species or components of $PM_{2.5}$ despite increasing evidence that some fractions or components of $PM_{2.5}$ may be more strongly associated with health effects than others. Although there is no evidence that any component is not at all associated with health impacts in epidemiological studies, some reviews (for example, Rohr and Wyzga [2012],[151] Achilleos et al. [2017],[152] and Yang et al. [2018][153]) have concluded that more scrutiny needs to be given to carbon-containing PM components (elemental and organic carbon).

[151] Rohr and Wyzga (2012). Attributing Health Effects to Individual Particulate Matter Constituents. Atmospheric Environment, 62: 130–152 (link).
[152] Achilleos et al. (2017). Acute Effects of Fine Particulate Matter Constituents on Mortality: A Systematic Review and Meta-Regression Analysis. Environment International, 109: 89–100 (link).
[153] Yang et al. (2018). Short-Term and Long-Term Exposures to Fine Particulate Matter Constituents and Health: A Systematic Review and Meta-Analysis. Environmental Pollution, 247: 874–882 (link).

More consideration should be given to confounding by gaseous co-pollutants.

EPA acknowledges confounding by co-pollutants as a potential source of uncertainty. The Health Benefits TSD (p. 136) notes that the associations between $PM_{2.5}$ and ozone and adverse health effects remain relatively unchanged after adjustment for additional pollutants. However, some published papers conducted multi-pollutant analyses and reported an attenuated association for the primary pollutant of concern. For example, Dominici et al. (2022)[154] concluded that "our final conclusions about the link between long-term exposure to $PM_{2.5}$ and increased all-cause mortality in the Medicare population at low levels of ambient $PM_{2.5}$ remain unchanged, although the effect size was attenuated." A meta-analysis conducted by Hart et al. (2011) also reported an attenuated association between $PM_{2.5}$ and mortality in multi-pollutant models that include SO_2 and NO_2.[155] To ensure that benefits calculations are accurate, EPRI suggests that the RIA more comprehensively account for uncertainties related to confounding by ozone, NO_2, and SO_2.

Additional consideration should be given to amine solvents used in carbon capture processes and their degradation products.

EPRI notes that the health benefits of reduced PM and ozone are quantified in Section 4.3 and additional unquantified benefits are discussed in Section 4.4 (Hazardous Air Pollutant Impacts, Section 4.4.1; NO_2 Health Benefits, Section 4.4.2; SO_2 Health Benefits, Section 4.4.3). However, EPRI notes that there is no qualitative discussion of potential air quality and resultant health impacts of the chemicals used in carbon capture and their byproducts. Of particular importance are amine solvents and various degradation products thereof that may have inherent toxicity.

Since 2009, EPRI has been conducting multidisciplinary research to understand the environmental behavior and toxicity of these chemicals. A list of relevant peer-reviewed literature and EPRI reports follows. This body of research—as well as work conducted by other groups—demonstrates the need for continued focus on these topics, especially if CCS is deployed in a more widespread manner. In particular, emissions measurements coupled with atmospheric modeling and exposure assessment needs to be conducted to evaluate the extent to which these impacts may be of concern for communities.

EPRI-Supported Research Products on Amines and Degradation Products

- Clegg, Qiu, and Zhang (2013). The Deliquescence Behavior, Solubilities, and Densities of Aqueous Solutions of Five Methyl- and Ethyl-Aminium Sulphate Salts. Atmospheric Environment, 73: 145–158 (link).
- EPRI (2011). *Emissions, Fate, and Transport of Amines Used in Carbon Capture*. EPRI Report 1024785 (link).
- EPRI (2011). *Amines Used in Carbon Capture: Potential Human Health Issues*. EPRI Report 1024784 (link).
- EPRI (2012). *Review of Test Methods for Stack Emissions of Amines and Degradation Products from Post-Combustion Carbon Capture Processes*. EPRI Report 1025020 (link).

[154] Dominici et al. (2022). Assessing Adverse Health Effects of Long-Term Exposure to Low Levels of Ambient Air Pollution: Implementation of Causal Inference Methods. Research Reports: Health Effects Institute, 211: 1–56 (link).
[155] Hart et al. (2011). Long-Term Ambient Multipollutant Exposures and Mortality. American Journal of Respiratory and Critical Care Medicine, 183(1): 73–78 (link).

- EPRI (2012). *Working Group Review of Sampling and Analytical Methods for Amines and Amine Degradation Products in Post-Combustion Carbon Capture Technologies*. EPRI Report 1026867 (link).
- Fjellsbo et al. (2014). Genotoxic and Mutagenic Potential of Nitramines. Environmental Research, 134: 39–45 (link).
- Ge, Shaw, and Zhang (2014). Toward Understanding Amines and Their Degradation Products from Postcombustion CO_2 Capture Processes with Aerosol Mass Spectrometry. Environmental Science & Technology, 48: 5066–5075 (link).
- Ge, Wexler, and Clegg (2011). Atmospheric Amines - Part I: A Review. Atmospheric Environment, 45: 524–546 (link).
- Ge, Wexler, and Clegg (2011). Atmospheric Amines - Part II: Thermodynamic Properties and Gas/Particle Partitioning. Atmospheric Environment, 45: 561–577 (link).
- Gentry et al. (2013). Potential Occupational Risk of Amines in Carbon Capture for Power Generation. Int. Arch. Occup. Environ. Health, 87(6): 591–606 (link).
- Lee and Wexler (2013). Atmospheric Amines - Part III: Photochemistry and Toxicity. Atmospheric Environment, 71: 95–103 (link).
- McDonald et al. (2014). Carbon Capture and Sequestration: An Exploratory Inhalation Toxicity Assessment of Amine Trapping Solvents and Their Degradation Products. Environmental Science & Technology, 48(18): 10821–10828 (link).
- Murphy et al. (2007). Secondary Aerosol Formation from Atmospheric Reactions of Aliphatic Amines. Atmospheric Chemistry Physics, 7:2313–2337 (link).
- Pankow (2015). Phase Considerations in the Gas/Particle Partitioning of Organic Amines in the Atmosphere. Atmospheric Environment, 122:448–453 (link).
- Rohr et al. (2013). Potential Toxicological Effects of Amines Used for Carbon Capture and Storage and Their Degradation Products. Energy Procedia, 37:759–768 (link).

EPRI suggests considering the corrected NOx volumetric measurement inadequacy when changing to a carbon-free fuel such as hydrogen.

Using typical corrected volumetric approaches to report NOx in emissions from blended hydrogen and hydrocarbon-based combustion leads to inflated NOx emissions for hydrogen-containing fuels relative to natural gas. NOx emissions measurements using dry, parts per million volume (ppmv) at a reference oxygen concentration of 15% results in an artificial increase in NOx production. Recent studies have shown that, under different methods, NOx emissions measurements can be overstated by up to 40%.[156] Moreover, for dry-low NOx (DLN) technology, 100% (or even 96%) hydrogen capabilities do not exist. Therefore, making assertions on NOx increases for technologies not developed is not appropriate.

[156] Noble et al. (2021). Hydrogen Substitution for Natural Gas in Turbines: Opportunities, Issues, and Challenges. Power Engineering (link).
Douglas et al. (2022). Pollutant Emissions Reporting and Performance Considerations for Hydrogen–Hydrocarbon Fuels in Gas Turbines. ASME Journal of Engineering for Gas Turbines and Power, 144(9): 091003 (link).

Establishing a NOx entitlement curve for hydrogen combustion, much like Leonard and Stegmaier's famous curve[157] for natural gas, is needed.

5.3. Climate and Net Benefits

Section Summary: The RIA calculations of climate benefits and net benefits lean heavily on estimates of the social cost of carbon (SCC). EPRI research has found that the SCC estimates currently being used in the RIA, as well as draft new estimates being considered for future use, should be revised to make them scientifically grounded and robust. Furthermore, the RIA's calculation of climate and net benefits need to be revised to address various technical issues, including inconsistencies in assumptions across calculations. Finally, the RIA is not considering the climate effects of expected non-CO_2 emissions changes associated with the rules. Specifically, reducing NOx and SO_2, which are indirect cooling agents, and producing hydrogen—a potential indirect warming agent—have possible warming implications that would offset some of the climate benefits of reducing CO_2. To properly inform the RIA and the public on the rules' potential benefits and for the public to have confidence in the results and insights, EPRI recommends that EPA revise the "interim" SCC methodology, reconstruct the net benefit calculations to address technical issues, and provide a more complete characterization of potential climate effects, climate benefits, and net benefits.

The social cost of carbon methodology and estimates should be revised to provide scientifically reliable climate benefit estimates.

This comment applies to both the "interim" inter-agency working group SCC estimates and draft new SCC estimates from EPA. The "interim" methodology contains significant technical issues, which were discussed in earlier EPRI comments and reports.[158] Rose et al. (2017) and EPRI (2014), in particular, provide a detailed assessment and diagnostic analyses of the approach.[159] The draft new methodology likewise has significant technical issues, as recent EPRI public comments have discussed.[160]

Given that substantial revisions are needed to the draft new methodology, documentation, and process—including an enhanced and appropriate peer review for a regulatory methodology with significant implications and dedicated public commenting opportunity following improvements to the methodology and documentation—for these rules and others over at least the next year, the interim methodology should be revised to satisfy a minimum scientific standard as described by EPRI (2021).[161] This would entail

[157] Leonard and Stegmaier (1994). Development of an Aeroderivative Gas Turbine Dry Low Emissions Combustion System. ASME Journal of Engineering for Gas Turbines and Power, 116(3): 542–546 (link).
[158] EPRI (2021). *Repairing the Social Cost of Carbon: Immediate Steps for Scientifically Reliable Estimates and Use*. EPRI Report 3002020523 (link).
EPRI (2021). *EPRI Public Comments on the Biden Administration's Interim Social Cost of Carbon, Methane, and Nitrous Oxide Estimates and Technical Document*. EPRI Report 3002022316 (link).
[159] Rose et al. (2017). Understanding the Social Cost of Carbon: A Model Diagnostic and Inter-Comparison Study, Climate Change Economics, 8(2) (link).
EPRI (2014). *Understanding the Social Cost of Carbon: A Technical Assessment*. EPRI Report 3002004657 (link).
[160] EPRI (2023). *EPRI Technical Public Comments on U.S. EPA's Draft New Social Costs of Carbon and Other Greenhouse Gases Estimation Methodology and Use of Estimates in EPA's Proposed Oil and Gas Methane Rule*. EPRI Report 3002026256 (link).
EPRI (2023). *EPRI Public Comments on U.S. EPA's Social Costs of Carbon and Other Greenhouse Gases Draft New Methodology Peer Review Process and Candidates*. EPRI Report 3002026087 (link).
Rose (2022). Putting Science First in Creating and Using the Social Cost of Carbon. The Hill (link).
[161] EPRI (2021). *Repairing the Social Cost of Carbon: Immediate Steps for Scientifically Reliable Estimates and Use*. EPRI Report 3002020523 (link).

removing results associated with models and inputs that do not satisfy minimum transparency, scientific justification, and plausibility requirements. Specifically, Table 7 identifies the PAGE model as failing to meet minimum scientific requirements for transparency, scientific justification, and scientific functionality.

Similarly, EPRI's *Repairing the Social Cost of Carbon* report (EPRI, 2021) shows that the low and high global emissions input projections do not meet plausibility requirements. Removing SCC estimates associated with PAGE and these two input scenarios from the distributions of interim estimates is straightforward and can be done quickly and immediately to produce more defensible distributions of SCC estimates and mean estimates (as well as estimates for other GHGs). See Table 8 for an example which reflects filtered available interim estimates (removing the PAGE and high and low emissions projection results) and recomputed 2020 SCC distributions and means, as well as uncertainty statistics—5th and 95th percentiles.

Table 7. Assessment of the three models used in the Biden Administration's Interim Social Cost of Methodology relative to minimum scientific requirements. Source: EPRI (2021).[162]

Table 1. *Model evaluation according to the minimum scientific standard*

Scientific Criteria	DICE	FUND	PAGE
Transparency	e.g., damages calibration	Most things described	e.g., unspecified discontinuity damages
Minimum scientific justification	e.g., quadratic damages	e.g., probabilistic parameters	e.g., unsubstantiated discontinuity damage, regional damages scaling, & probabilistic parameters
Minimum scientific functionality	e.g., no climate feedback	e.g., partial radiative forcing	e.g., climate modeling missing structural element
Plausibility	Adequate	e.g., some probabilistic outcomes	e.g., some probabilistic outcomes

Green evaluation indicator = adequate; Yellow = meets minimum but could be improved; Red = inadequate.
Text entries are examples of model specific issues listed in the previous section that support the evaluation color.

Table 8. Recomputed and original distributions of interim SCC estimates for 2020 (in 2020 U.S. dollars). Source: EPRI (2021).[163]

Table 2. *SCC estimates for CO_2 emissions in 2020 from repairing the IWG Framework to be consistent with the minimum scientific standard ($2020). Repaired and orginal estimates shown.*

	Discount rate	5th percentile	Average	95th percentile
Repaired framework SCCs for 2020	**2.5%**	$5	$64	$147
	3%	$1	$40	$94
	5%	($4)	$10	$27
Original IWG Framework SCCs for 2020	**2.5%**	$5	$79	$228
	3%	$2	$53	$157
	5%	($3)	$15	$45

[162] EPRI (2021). *Repairing the Social Cost of Carbon: Immediate Steps for Scientifically Reliable Estimates and Use*. EPRI Report 3002020523 (link).
[163] EPRI (2021). *Repairing the Social Cost of Carbon: Immediate Steps for Scientifically Reliable Estimates and Use*. EPRI Report 3002020523 (link).

Although the draft new SCC estimates are not currently applied in the RIA for the proposed rules, EPA notes that it plans to apply these estimates in the final rule if the estimates are finalized in time. EPRI's February 2023 public comments[164] identified significant scientific issues—as well as specific improvements needed to the draft new methodology, documentation, and process, including an appropriate peer review (beyond that conducted so far)—to achieve scientific reliability. The scientific issues include not satisfying the National Academies of Sciences, Engineering, and Medicine's[165] (NASEM's) recommendations (for example, Recommendations 2-2, 3-1, 3-2, 4-1, 4-2, 4-5, and 5-1) as well as technical issues with the methodology such as insufficient transparency and justification for full and proper assessment, inadequate consideration of current scientific knowledge, inadequate consideration of uncertainty, inconsistencies within and across modules, missing elements, insufficient support for existing elements, and critical technical issues within each module (socioeconomic and emissions projections, climate modeling, climate damage estimation, and discounting). Note that the recently completed peer review of EPA's draft new methodology identified similar substantive issues that should be addressed, including the NASEM recommendations; insufficient documentation, details, and discussion for proper review; and plausibility, uncertainty, and biases that all suggest the need for revisions, as well as further, and more expansive, peer review and public commenting.

The climate and net benefits estimates should be made more scientifically reliable by addressing technical issues with how the SCC estimates are applied to calculate the proposed rules' climate benefits and with the subsequent net benefits calculations.

Technical issues found when assessing past policy applications of SCC estimates[166] are evident in the proposed rules' RIA and should be addressed in applying any SCC estimates. Similar, or identical, issues have been noted previously.[167] Specifically, the following technical issues are found in this RIA and should be addressed:

- **Inconsistencies in benefit and cost calculation assumptions and uncertainty.** There are inconsistencies in the assumptions used and treatment of uncertainty in calculating the SCC estimates, future emissions changes, and compliance costs. For instance, the RIA's estimated CO_2 emissions and compliance costs come from IPM modeling, whose projections are based on AEO 2021 economic, energy system, and market projections. The RIA's SCC estimates, on the other hand, are based on a set of other economic and energy system projections. See Figure 39 for a

[164] EPRI (2023). *EPRI Technical Public Comments on U.S. EPA's Draft New Social Costs of Carbon and Other Greenhouse Gases Estimation Methodology and Use of Estimates in EPA's Proposed Oil and Gas Methane Rule*. EPRI Report 3002026256 (link).
[165] Cropper et al. (2017). Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies of Sciences, Engineering, and Medicine (link).
[166] EPRI (2021). *Repairing the Social Cost of Carbon: Immediate Steps for Scientifically Reliable Estimates and Use*. EPRI Report 3002020523 (link).
Bistline and Rose (2018). Social Cost of Carbon Pricing of Power Sector CO_2: Accounting for Leakage and Other Social Implications from Subnational Policies. Environmental Research Letters, 13: 014027 (link).
EPRI (2016). *Applying the Social Cost of Carbon: Technical Considerations*. EPRI Report 3002004659 (link).
[167] EPRI (2023). *EPRI Technical Public Comments on U.S. EPA's Draft New Social Costs of Carbon and Other Greenhouse Gases Estimation Methodology and Use of Estimates in EPA's Proposed Oil and Gas Methane Rule*. EPRI Report 3002026256 (link).
EPRI (2022). *EPRI Public Comments on Federal Acquisition Regulation ANOPR: Minimizing the Risk of Climate Change in Federal Acquisitions*. EPRI Report 3002023465 (link).
EPRI (2021). *EPRI Public Comments on the Biden Administration's Interim Social Cost of Carbon, Methane, and Nitrous Oxide Estimates and Technical Document*. EPRI Report 3002022316 (link).

comparison of the AEO 2021 and SCC socioeconomic projections for select U.S. economic and energy system variables. As shown in Figure 39, the IPM and SCC projections are inconsistent in terms of the projected future economy and energy system, as well as the socioeconomic uncertainty represented. The socioeconomic assumptions have been shown to have a significant impact on the SCC estimates (for example, EPRI, 2016[168]), but socioeconomic uncertainty is not considered in the RIA's projected emissions and compliance costs. Consistency across calculations in the projected futures and treatment of uncertainty are important for meaningful comparison of benefits and costs.

- **Net benefit calculation discounting inconsistencies.**
    - The RIA presents present value (PV) climate benefits where the annual benefits have been discounted with a 3% discount rate. These values are then compared to PV compliance costs calculated with a 7% discount rate. For consistency, and a meaningful 7% PV net benefit calculation, climate benefit PV calculations with 7% are needed that, along with the consistent 7% PV compliance costs, can be used to derive appropriate 7% PV net benefit estimates.
    - Equivalent annualized values (EAVs) should be revisited—first, in terms of whether they should be included at all; second, if included, revising them for consistency across calculations. In general, EAV calculations are unnecessary given the availability of the PV calculations, and should be removed. PV is more readily understood and is sufficient once corrected for discounting consistency. Regarding consistency, the RIA computes annualized cost values (labeled "EAV") with 3% and 7% discount rates, while computing annualized (EAV) climate benefits with 2.5%, 3%, and 5% discount rates. Although there are reasons for the SCC estimates to be computed with different discount rates than the compliance costs, the EAV and PV calculations for costs and benefits should use the same discounting when aggregating annual values over time in the EAV and PV calculations for comparison. Note, however, that the EAV calculations can be misleading given the way they are calculated with inconsistent discounting.
- **Accounting for SCC uncertainty for each given discounting structure.** The RIA uses the mean SCC values computed with a 3% constant discount rate. As recommended by NASEM (2016), to fully inform the rules, the analysis should consider SCC uncertainty for a given discount rate (for example, the 1st and 99th or 5th and 95th percentiles of the SCC results with 3%).[169] See Table 8 for examples. For instance, the recomputed distributions for 2020 SCCs with a 3% discount rate have a mean of \$40/t-CO_2 and 5th and 95th percentiles of \$1 to \$94/t-CO_2. In addition, the net benefit calculations should also be provided using the other SCC distributions (for example, 1st, mean, and 99th) for the other discount rates—2.5% and 5%.
- **Accounting for emissions leakage.** Potential changes in CO_2 and non-CO_2 emissions (for example, SO_2) beyond the regulated sources in the economy would affect the net climate benefits of the proposed rules. These potential effects should be evaluated in the RIA. Such emissions leakage effects are plausible given the energy market effects (production and price changes) outside the power sector that may result from the proposed rules as well as previous EPRI

[168] EPRI (2016). *Applying the Social Cost of Carbon: Technical Considerations*. EPRI Report 3002004659 (link).
[169] Cropper et al. (2016). Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update. National Academies of Sciences, Engineering, and Medicine (link).

analyses that have found the potential for notable leakage from power-sector-focused carbon policies.[170]

- **Pricing CO_2 more than once across policies.** The proposed rule appears to be implicitly pricing the same CO_2 molecules that are being priced by other policies. For instance, federal procurement policies considering (or even pricing) federal contractor GHG emissions—as well as mineral extraction policies considering the carbon content of oil and gas—would be valuing the same carbon that is represented in the projected CO_2 emissions of the proposed rules. See EPRI (2022)[171], EPRI (2021)[172], and EPRI (2016)[173] for discussions of this economic efficiency issue, which increases the cost of decarbonization without emissions reduction benefits.[174]

The full climate effects of the proposed rules should be considered.

The climate benefits and net benefits calculations do not consider the climate effects of the non-CO_2 emissions changes expected with the proposed rules. Reducing NOx and SO_2, which are indirect cooling agents, and producing hydrogen—a potential indirect warming agent—has potential warming implications that would offset some of the climate benefits of the CO_2 reductions associated with the rules. See, for instance, IPCC (2021)[175] for a recent discussion of the significant historical cooling effects of SO_2 and NOx, Rose et al (2013)[176] for evaluation of the potentially significant near-term cooling offsetting effects of these climate forcers in global decarbonization strategies, as well as Bertagni et al. (2022)[177] for a recent discussion of increased hydrogen production's potential warming implications. The indirect cooling effects of SO_2 and NOx emissions as aerosol radiative forcing precursors have been known for some time because of volcanic eruptions and are the reason geoengineering strategies projecting aerosol emissions into the upper atmosphere are being considered as potential options to manage climate change. To properly inform the RIA and the public on the net climate effects of the rules, EPA should account for the climate implications of the expected changes in SO_2, NOx, and fugitive emissions from hydrogen production, transmission, and distribution activities.

[170] Bistline and Rose (2018). Social Cost of Carbon Pricing of Power Sector CO_2: Accounting for Leakage and Other Social Implications from Subnational Policies. Environmental Research Letters, 13: 014027 (link).
[171] EPRI (2022). *Opportunities for Decarbonizing Minnesota's Economy: Energy System Supply and Demand Assessment*. EPRI Report 3002019333 (link).
[172] EPRI (2021). *Repairing the Social Cost of Carbon: Immediate Steps for Scientifically Reliable Estimates and Use*. EPRI Report 3002020523 (link).
[173] EPRI (2016). *Applying the Social Cost of Carbon: Technical Considerations*. EPRI Report 3002004659 (link).
[174] EPRI (2022). *EPRI Public Comments on Federal Acquisition Regulation ANOPR: Minimizing the Risk of Climate Change in Federal Acquisitions*. EPRI Report 3002023465 (link).
[175] IPCC (2021). Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change (link).
[176] Rose et al. (2013). *Non-Kyoto Radiative Forcing in Long-Run Greenhouse Gas Emissions and The Role of Non-Kyoto Gas Forcing in GHG Stabilization Scenarios.* Climatic Change 123: 511–525 (link).
[177] Bertagni et al. (2022). Risk of the Hydrogen Economy for Atmospheric Methane. Nature Communications, 13: 7706 (link).

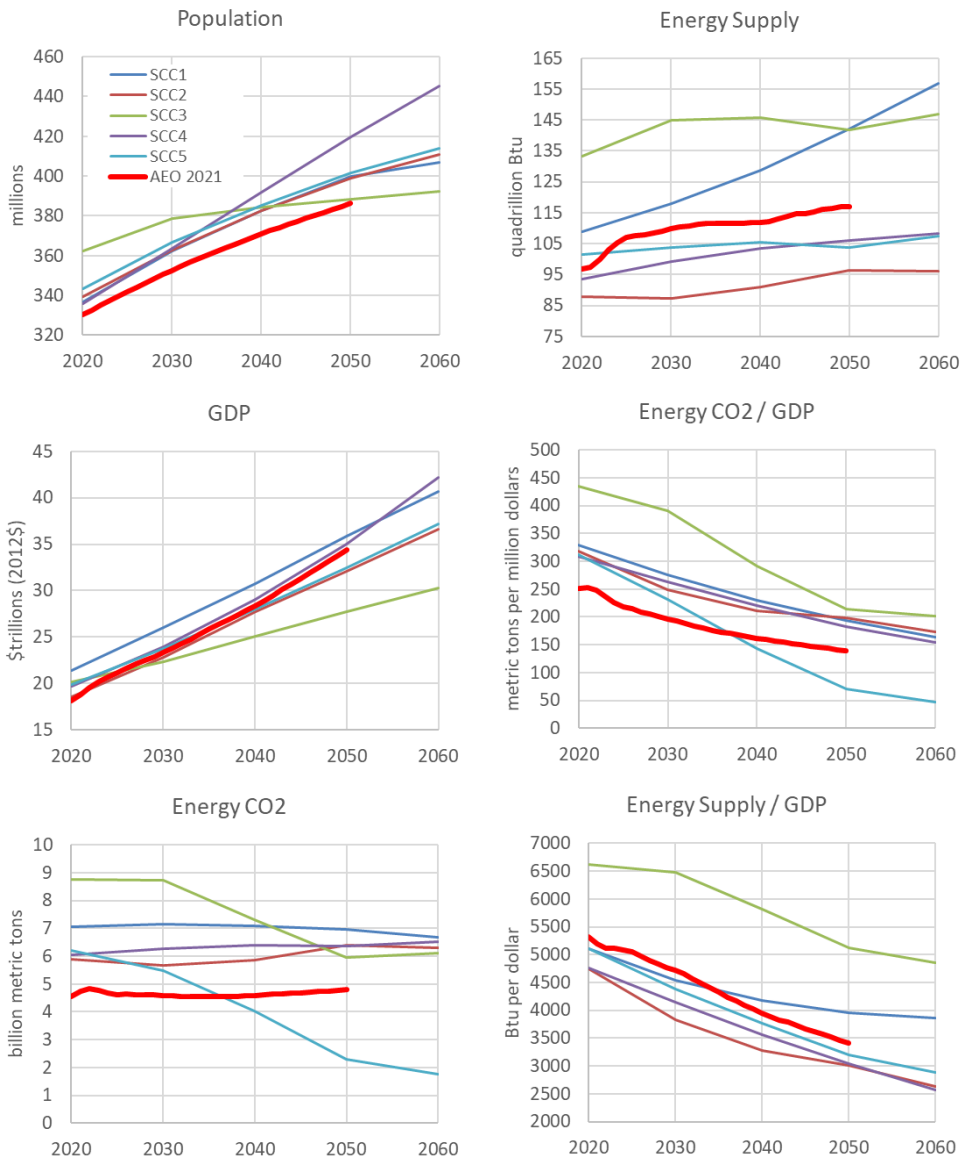


Figure 39. Comparison of CO_2 reduction and compliance cost reference U.S. assumptions used by the RIA's IPM modeling (AEO 2021) with the "interim" USG SCC assumptions being used. Developed by EPRI from AEO 2021 and Rose et al. (2017)[178] analysis of the interim SCC methodology.

5.4. Environmental Justice

Section Summary: The Environmental Justice (EJ) Impacts section of the RIA analyzes the effects of the proposed rules on disadvantaged communities rather than incorporating EJ considerations into rule development itself. The EJ analysis approach in the RIA also focuses solely on air quality impacts,

[178] Rose et al. (2017). Understanding the Social Cost of Carbon: A Model Diagnostic and Inter-Comparison Study, Climate Change Economics, 8(2) (link).

omitting other EJ-related impacts. There are several notable omissions from the EJ analysis, including natural gas plant impacts, cumulative impacts, and effects of BSER technologies.

When discussing EJ and equity in the context of these new rules, it is important to understand and identify which types of justice are impacted and how they may be realized as benefits.

EPRI recognizes the following categories of environmental justice to be applicable to this issue:[179]

- **Procedural justice** deals with the fairness and transparency of the processes that allocate resources and is concerned with making and implementing decisions according to fair processes, with transparency and impartiality, and a focus on inclusive and authentic engagement.
- **Distributive justice** is about the fairness in the distribution of benefits and burdens across all segments of a community or society, including the allocation of rights, resources, or information. It also pertains to economic justice and members of society getting a "fair share" of available benefits and resources.
- **Recognition justice** involves understanding historical, cultural, and institutional factors as well as respecting peoples' assumptions, values, and knowledge. It is important to recognize that historical and other issues may still impact these communities in ways that may include redlining, underinvestment, disenfranchisement, and exclusion from decision-making.
- **Intergenerational justice** pertains to decision-making around aspects related to obligations to future generations. Actions that increase rather than limit the development options for future generations can be said to improve intergenerational equity.
- **Restorative justice** pertains to the reparation of present and future harm as well as remediating past harms.

These justice categories can be applied and practiced in different ways, and some actions or regulations may consider one or more category without addressing every category.

The EJ Impacts analysis section of the RIA seeks to answer three questions (pp. 6-3 and 6-4):

1. Are there potential EJ concerns associated with environmental stressors affected by the regulatory actions for population groups of concern in the baseline?
2. Are there potential EJ concerns associated with environmental stressors affected by the regulatory actions for population groups of concern for the regulatory option(s) under consideration?
3. For the regulatory option(s) under consideration, are potential EJ concerns created, exacerbated, or mitigated compared to the baseline?

These questions address recognition justice and intergenerational justice because of the longevity of pollution and GHG emissions in the atmosphere. The EJ analysis provides evidence of historical injustices as a result of the operation of the types of power plants considered in this rule and analyzes the impacts this rule may have on existing disadvantaged communities. This is a useful analysis and can inform future decisions and planning when there is a better understanding of how decarbonization and emission reductions may impact these communities. However, this analysis is incomplete relative to some

[179] EPRI (2023). *Program on Technology Innovation: Environmental Justice and Carbon Capture and Storage*. EPRI Report 3002026035 (link).
EPRI (2022). *Environmental Justice and Renewable Energy and Storage*. EPRI Report 3002024572 (link).

of the EJ categories discussed above. Because the distributional impacts of the rules were analyzed after the rules had been determined, this may not be considered distributive justice—fairness of the distribution of impacts, specifically benefits, was not a driver of policy development. The questions driving this analysis importantly do not address procedural, distributive, or restorative justice. Because of the large gaps in the questions this analysis is seeking to answer, this analysis would be more complete if the questions and assessment were updated to directly include all the pillars of environmental justice.

The distinction between recognition justice and distributional justice in this context is especially important following the release of the revisions to Circulars A-4 and A-94,[180] in which a new recommended approach to EJ analyses was proposed. The purpose of a distributional analysis, as stated in Circular A-4, is to "allow for more effective consideration of regulatory alternatives," by conducting distributional analyses for this rule and feasible regulatory alternatives, in which benefits are disaggregated, allowing the analysis to identify who is receiving what quantity of benefits. By using this more granular approach, efficiency or the maximization of net benefits is no longer the primary goal. Instead, this type of analysis allows for regulations to optimize for social welfare and for an outcome that creates the largest improvement in equity and justice. Completing a distributional analysis prior to the proposal or a regulation to maximize benefits to disadvantaged communities is an example of distributive justice, which does not apply to the EJ analysis in this RIA. Similar analyses may be applied to identify opportunities for restorative justice, including historical impacts or harms, whether these are or will be ongoing for some communities and considering what future benefits may mitigate or address these harms. In addition, recognition justice and procedural justice would apply to these analyses in that involving impacted communities is important to identifying and understanding the burdens and benefits along with the communities' needs to determine impacts and appropriate mitigation strategies.

Existing natural gas plants should be included for a more comprehensive assessment of potential EJ impacts of the proposed rules.

The EJ analysis in the RIA includes three categories of coal plants but omits natural gas plants entirely. This can lead to understated results of the air quality impacts to the specified communities in two ways:

- **Exclusion of communities and gas plants from the analysis.** Excluding communities that are exposed to emissions from gas plants also excludes the individuals who live within the specified distance in the analysis, reducing the total EJ impacts associated with air quality improvements caused by the rules. In addition, excluding these communities results in an exclusion of combined impacts of living within the specified distance from one or more gas plants and one or more coal plants, which may create a cumulative impact on air quality. Another crucial component is the analysis of air quality changes of peaker plants and other natural gas plants that are not within the threshold designated by these rules.
- **Underestimation of emissions reductions.** As mentioned in Section 5.1, the IPM modeling used to determine the EJ impacts on the specified communities likely understates the emissions reductions and associated benefits of these rules. This may be the reason the air quality impacts and benefits of air quality improvements for the specified communities were modest.

[180] OMB (2023). Circular A-4 Revisions (link).
OMB (2023). Circular A-94 Revisions: Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs (link).

The inclusion of natural gas plants and the associated communities in the EJ analysis, in addition to adjusting for the understatement of emissions, may create a more robust picture of how benefits of these new rules may be realized by the specified communities.

Additional information and extensions of the EJ analysis could provide more complete assessments of the impacts of the proposed rules.

The presented analyses explore each of the chosen EJ indicators individually, which does not address the important understanding of potential cumulative impacts that certain communities may experience upon the implementation of the proposed rules. There is also a lack of clarity about how communities located within the specified distances from two or more coal plants, one or more gas plants, or a combination of gas and coal plants may experience differences in air quality impacts. The cumulative impacts, as defined by the CDC,[181] of living within several units are worth noting, as are the benefits that may result from residing within the specified distance from several power plants and experiencing an improvement in air quality that is double or more than communities located only within the specified distance from one power plant.

The analysis should be extended from just air quality impacts, as this is not the only determinant of environmental justice.[182] Processes for the construction and implementation of BSER technologies, siting decisions, and long-term implications of the BSER technologies need to be assessed through the lens of environmental justice, including:

1. Meaningful involvement of communities in the siting and construction process
2. Assessment of the impacts of BSER technologies and emission reduction on communities so that improvements in equity and reductions of injustice are optimized
3. Understanding of demographic and historical injustices and how these may create cumulative impacts faced by these communities
4. How the selected BSER technology may impact future generations and how benefits may improve the conditions of these communities over time, including air quality, water quality, economic and workforce changes, and other considerations

In particular, a discussion of potential implications of CCS technologies for the EJ communities is not provided. CCS is considered a potential BSER technology for coal and gas plants affected by this regulation, but the RIA does not include the implications of CCS or other BSER technologies in the Environmental Justice Impact Analysis. The omission of these impacts gives the impression that EJ can be quantified as air quality and proximity to fossil fuel plants, which is a narrow assessment of environmental justice impacts. This excludes the impact of technologies on property values; public health (distinct from health impacts of air quality); water availability and scarcity; cultural, historic, or religiously important sites; and impacts of polluting facilities.

[181] CDC (2022). 2022 Environmental Justice Index (link).
[182] EPRI (2023). *Program on Technology Innovation: Environmental Justice and Carbon Capture and Storage*. EPRI Report 3002026035 (link).
EPRI (2023). *Equity and Environmental Justice Considerations for Coal-Fired Plant Repowering*. EPRI Report 3002026486 (link).
EPRI (2023). *Equity and Environmental Justice Considerations for a Clean Energy Transition*. EPRI Report 3002021206 (link).

These excluded impacts are an example of how seeking to answer only the three questions proposed for the section is limiting and excludes costs and benefits that may disproportionately fall on disadvantaged communities. There are also expected air emissions associated with CCS technologies; in particular, amine solvents and their degradation products may be released. The public health impacts of these emissions are unclear and require further research (see EPRI comments on RIA Section 5.2 for more details).

Additional analyses should be conducted to understand the impact of the proposed rules on disadvantaged communities.

EPRI suggests conducting additional analyses to understand the potential local impacts of the proposed rules. Understanding and addressing local conditions is a critical part of achieving environmental justice. The local implications should be examined more carefully to ensure fair treatment following the implementation of the rules. The RIA states, "Also, due to the very small differences in the distributional analyses of post-policy exposure impacts across demographic populations, we do not find evidence that disparities in populations of potential EJ concerns will be meaningfully exacerbated or mitigated by the regulatory alternatives under consideration regarding $PM_{2.5}$ exposures in all future years evaluated and ozone exposures in 2028, 2035, and 2040. However, in 2030, Asian populations, Hispanic populations, and those linguistically isolated may experience a slight exacerbation of ozone exposure disparities at the national level" (RIA, p. 6-32). Additional analyses should be conducted for those populations that have been shown to experience an exacerbation of ozone to identify the contributing factors/local characteristics to proactively address a potentially disproportionate burden that may be placed on disadvantaged communities.

Providing underlying information considered in EJ impacts assessment could help readers better understand impacts of the proposed rules.

Educating, involving, and engaging with members of EJ communities in a meaningful way are critical in advancing environmental justice. However, the RIA does not provide sufficient information for EJ communities to understand the impacts of the proposed rules. For example, Figures 6-7 and 6-8 indicate increases in ozone under certain scenarios (for example, 2028 more stringent scenario) and/or in certain states (2030 more stringent scenario for Maryland). These can be confusing findings to the public or non-scientific readers because one would expect improvements in air quality under a more stringent policy. Providing additional scientific background information on what might be contributing to such results—for example, the NOx titration impact on ambient ozone—will be a meaningful addition to the document. EPRI suggests that EPA consider providing basic underlying science information to those who want to read and understand the proposed rules.

6. Technical Support Documents

6.1. Hydrogen in Combustion Turbine Electric Generating Units

The flame speed for hydrogen is due to the higher heat release from the reaction and not higher flame speed, as supporting documents for the rules claim.

Page 4 of the hydrogen turbine TSD[183] mentions that "A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components as well as increase thermal NOx emissions." Hydrogen combustion does not necessarily result in higher component temperatures due to high flame speed. Hydrogen's flame speed is higher because it is more reactive. Temperature is directly controlled in the gas turbine regardless of fuel. In older, diffusion technology combustion systems, local flame temperatures may be higher and result in higher NOx. However, modern, premixed systems regulate the local and bulk flame temperatures, which results in lower temperatures and improved NOx performance relative to diffusing systems. One option with hydrogen, based on the improved heat rate and power output in Figure 40, would be to lower the gas turbine firing temperature.[184]

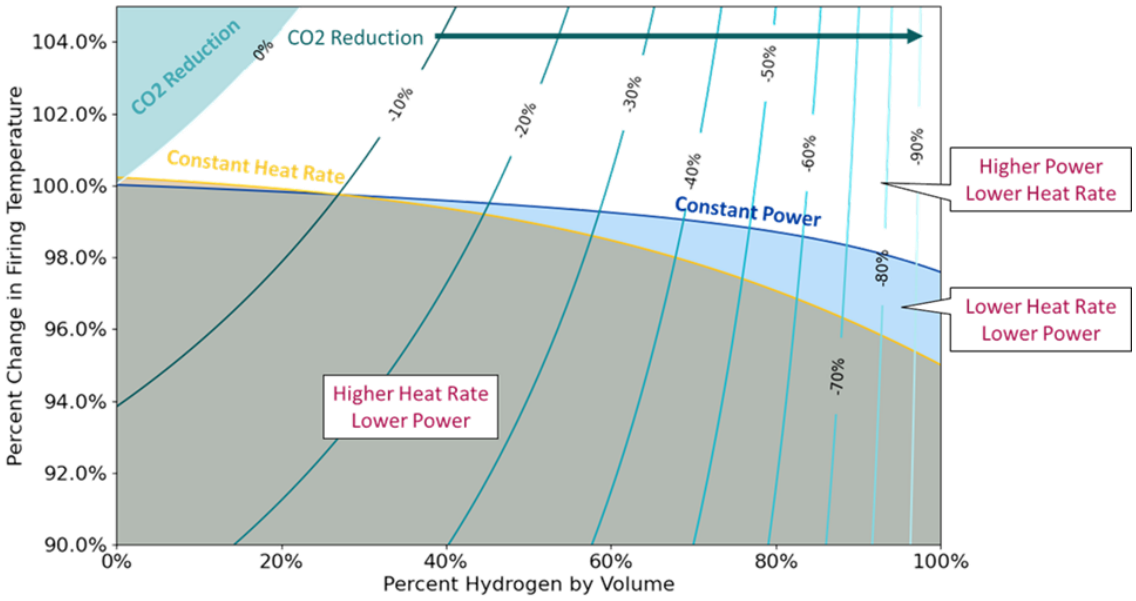


Figure 40. Controlling energy input by changing firing temperature. Calculated using EPRI's GT Digital Twin for a 7FA.

The TSD oversimplifies hydrogen capabilities and does not adequately distinguish between technologies with different characteristics.

In Figure 2 of the TSD and surrounding text (p. 7), the document oversimplifies hydrogen capabilities and combines older (higher NOx) diffusion or WLE technology and newer (low NOx) premixed or DLN

[183] U.S. Environmental Protection Agency (2023). Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document (link).
[184] EPRI (2023). *Hydrogen-Capable Gas Turbines for Deep Decarbonization*. EPRI Report 3002017544 (link).

technologies. Most, if not all, gas turbines that fall within the definition in the proposed rules are currently, or are anticipated to be, DLN technology by 2032, which means that current capabilities as presented (that is, grouping high capability diffusion technologies with currently lower capability DLN technologies) could exaggerate the readiness for the 96% hydrogen target. In addition, the desire for low NOx, which can be achievable through the DLN technology via control of reaction temperature, could mean that DLN combustion hardware is desired. It is suggested to follow the outline of original equipment manufacturers' stated capabilities (according to Table 9, from NETL), where full delineation is incorporated between diffusion and premixed systems.[185]

Table 9. Comparison of hydrogen combustion turbine technologies. Based on NETL (2022).

OEM	Type	TIT or Frame Type	H_2 (vol%)	Notes
MHI	Diffusion	1,200–1,400°C (2,192–2,552°F)	Up to 100%	N_2/Water/Steam Injection
	Pre-Mixed (DLN)	1,600°C (2,912°F)	Up to ~30%	Dry
	Multi-Cluster	1,650°C (3,002°F)	Up to 100%	Dry—Under Development (2024)
GE	DLE	—	Up to 5%	Aeroderivative—Dry, Low Emissions
	SAC	—	30-85%	Aeroderivative—Singular Annular Combustor
	SN	B/E	90–100%	Single Nozzle (Standard)
	MNQC	E/F	90–100%	Multi-Nozzle Quiet Combustor (w/N_2 or Steam)
	DLN 1	B/E	Up to ~33%	Dry, Low-NO_x 1
	DLN 2.6+	F/H	Up to ~15%	Dry, Low-NO_x 2.6
	DLN 2.6e	9HA	Up to 50%	Dry, Low-NO_x 2.6 "Evolution" (to be implemented in other models)
Siemens	DLE	—	2–15%	Aeroderivative
	WLE	—	15–100%	Aeroderivative—Wet, Low-NO_x
	DLE	E/F/H	Up to 30%	—
	Diffusion	E/F/H	Up to 100%	No NO_x Abatement
	DLE	HL	Up to 30%	—

In addition, EPRI's interpretation of Reference 14 (Douglas et al., 2022, "Pollutant Emissions Reporting and Performance Considerations for Hydrogen-Hydrocarbon Fuels in Gas Turbines" in *Journal of Engineering for Gas Turbines and Power*) is that, for the same NOx mass production, the traditional corrected parts per million (ppm) value is not a proper capture of NOx output. Traditional corrected ppm looks at a "dry" measurement (so removed H_2O) and 15% O_2, which is based on typical remaining O_2 from hydrocarbon combustion. Hydrogen combustion produces H_2O in place of CO_2 and burns at a higher remaining percentage of O_2, which both work against hydrogen combustion when considering for a corrected concentration measurement. A correction factor is needed for corrected ppm measurements or ideally a different way to account for true NOx production, as outlined in Reference 14.

[185] NETL (2022). A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOx Control. DOE/NETL-2022/3812 (link).

6.2. Efficient Generation Combustion Turbine Electric Generating Units

The text on efficiency changes when burning hydrogen should be updated and expanded.

Page 4 of the efficient combustion turbine TSD[186] mentions that efficiency drops when burning distillate oil or hydrogen. However, efficiency does not drop for hydrogen, so the text should be updated accordingly. It would be helpful to have magnitudes of efficiency changes provided, as well as mentioning the increase in fouling when using distillate or other liquid fuels and the shortened maintenance intervals.

6.3. Simple-Cycle Stationary Combustion Turbine EGUs

Emissions data should account for a broader range of gas turbine technologies.

A limited data set is used to establish guidelines for CO_2 emissions rates from simple-cycle gas turbines in the simple-cycle TSD.[187] The data set is limited to newest gas turbines installed between 2015 and 2021 and is primarily based on highest-efficiency simple-cycle gas turbines, such as the GE LMS 100 and high-efficiency LM6000PF models. This does not include emission data for the LM 6000PC gas turbine, which is the most common simple-cycle gas turbine used for electric power generation.

The proposed standard is inconsistent with the current population of recently installed simple-cycle gas turbines used in power generation. The proposed CO_2 emission rates of less than 1100 lb/MWh (primarily based on the GE LMS 100 and high-efficiency LM6000PF models) are too low to be inclusive of all recently permitted (2015–2021) simple-cycle gas turbines. Including other manufacturers would entail a higher rate of 1500 lb/MWh or greater.

Emissions rates should consider actual part-load operational data and emissions.

The methodology used for establishing CO_2 emission limits does not include actual part-load CO_2 emission rates. The methodology infers part-load CO_2 emission rate based on an average duty cycle and not on actual part-load operational data and actual emissions. The methodology does not include spinning reserve CO_2 emission rates.

[186] U.S. Environmental Protection Agency (2023). Efficient Generation: Combustion Turbine Electric Generating Units Technical Support Document (link).
[187] U.S. Environmental Protection Agency (2023). Simple-Cycle Stationary Combustion Turbine EGUs Technical Support Document (link).

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