Exhibit A

Review of EPA's Section 111
May 23, 2023 Proposed Rule for the
State of South Carolina

On Behalf of

South Carolina
Office of Regulatory Staff

August 8, 2023

Prepared By:
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Exhibit A

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I. Background

On May 23, 2023, the Environmental Protection Agency ("EPA") proposed New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule ("Proposed Rule").[1] The EPA also requested public comments within 60 days of the issuance of the rule.

The Proposed Rule was issued under Sections 111(b) and 111(d) of the Clean Air Act ("CAA"), which was enacted in 1970, and subsequently amended in 1977, and 1990. The 1970 CAA enacted four major federal and state regulatory programs to limit emissions from both stationary and mobile sources. The four regulatory programs enacted that affect stationary sources are the National Ambient Air Quality Standards ("NAAQS"), State Implementation Plans ("SIPs"), New Source Performance Standards ("NSPS"), and National Emission Standards for Hazardous Air Pollutants ("NESHAPs"). The EPA was created at the end of 1970, and has been responsible to implement the requirements under the CAA.[2]

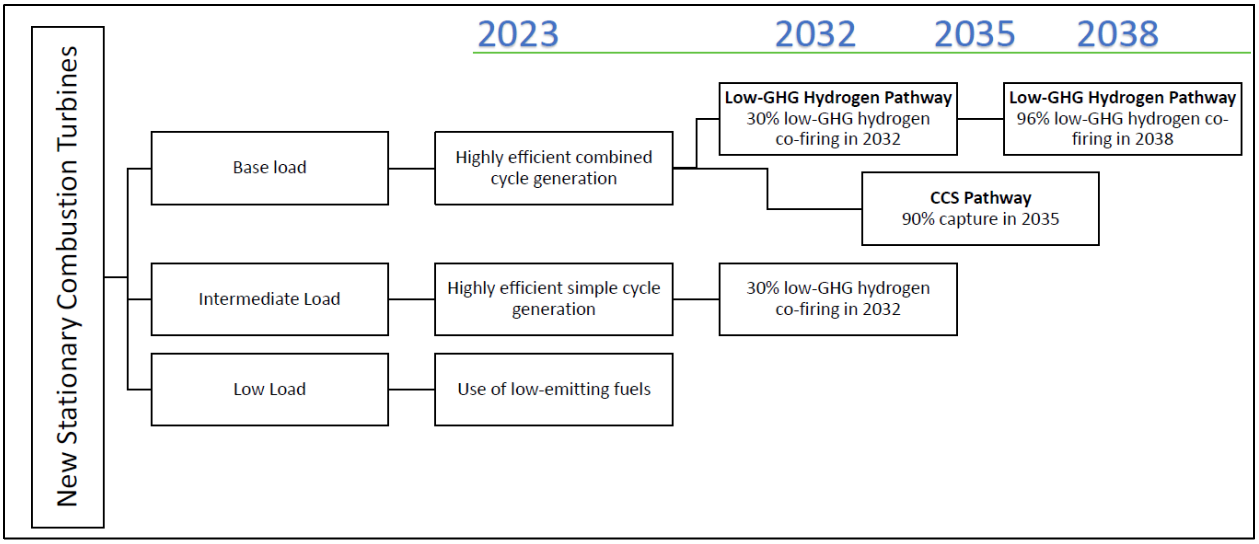
The Proposed Rule defines performance standards for new generating units, referred to as NSPS, and guidelines for existing electric generating units ("EGU's"). As part of the Proposed Rule, a regulatory impact analysis ("RIA") was provided that identified the costs and benefits of the Proposed Rule. The South Carolina Office of Regulatory Staff ("ORS") requested J. Kennedy and Associates, Inc.'s ("Kennedy") assistance to review and analyze the RIA, and to assist with the development of comments and/or recommendations related to the Proposed Rule.

The Proposed Rule includes several complex compliance actions that must be taken by EGU owners to reduce carbon dioxide ("CO_2") emissions over time. The compliance options vary based on EGU threshold size, utilization, and fuel type. The EPA attributed standards for new and reconstructed combustion turbines ("CTs") to the CAA's Section 111(b) and attributed emission guidelines for existing fossil fuel-fired EGUs, including existing coal and gas/oil steam turbine generating units, and existing large, frequently used CTs to the CAA's Section 111(d). The EPA identified a series of best system of emission reduction ("BSER") options that it expects EGUs to rely on, which include burning low greenhouse gas hydrogen ("low-GHG hydrogen"), carbon capture and storage ("CCS"), limits for EGUs to operate below 20% capacity factors, use of low CO_2 emitting fuels, construction of highly efficient generating units, and co-firing with natural

[1] 88 Fed. Reg. No. 99 (May 23, 2023).
[2] https://www.epa.gov/clean-air-act-overview/evolution-clean-air-act

gas. The following depicts the Section 111(b) standards for new and reconstructed CTs under EPA-111(b) and the available BSER options that vary over time.

Figure 1: NSPS Combustion Turbines[3]



Low Load CT resources are EGUs that operate at capacity factors less than 20% and will be required to use low CO_2 emitting fuels. These fuels include natural gas and distillate oil that produce less than 120 to160 lbs. of CO_2 per MMBtu, respectively.[4]

Intermediate Load CTs are EGUs that operate at capacity factors between 20% - 50% and will have a two-phased BSER requirement. Beginning in 2023 (Phase 1), Intermediate Load CTs must be highly efficient and produce less than 1,150 lbs. CO_2 per megawatt-hour ("MWh"). Beginning in 2032 (Phase 2), intermediate CTs must begin co-firing with a mixture of 30% low-GHG hydrogen and produce less than 1,000 lbs. CO_2/MWh during that phase.

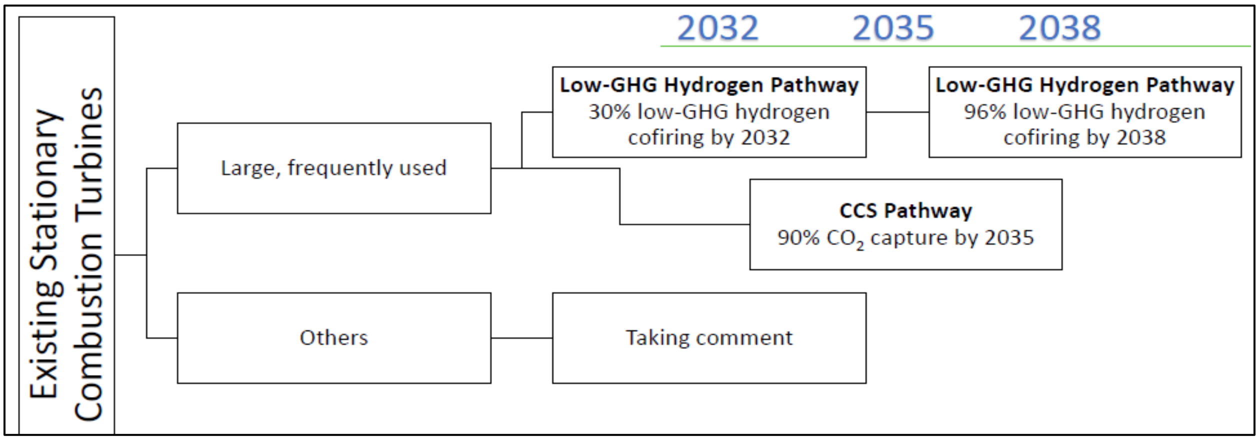
Base Load CTs are EGUs that operate at capacity factors greater than 50% and will have phased requirements and pathway options. Beginning in 2023 (Phase 1), Base Load CTs must produce no more than 770 lbs. CO_2/MWh. There are two pathways for Base Load units after Phase 1, either a hydrogen pathway or a CCS pathway. Under the hydrogen pathway, beginning in 2032 (Phase 2), the EGU must begin co-firing with a mixture of 30% low-GHG hydrogen and cannot produce more than 680 lbs. CO_2/MWh. Beginning in 2038 (Phase 3), under the hydrogen pathway, Base Load CTs must increase to 96% co-firing using low-GHG hydrogen and produce no more than 90 lbs. CO_2/MWH.

[3] 111 Power Plants Stakeholder Presentation_Webinar June 2023.pdf, p. 14.
[4] Regulatory Impact Analysis documentation, utilities_ria_proposal_2023-05.pdf, p. ES-3.

Alternatively, under the CCS pathway, there is just a Phase 2 requirement that begins in 2035, in which the Base Load CT must use CCS to capture 90% of the CO_2 emissions.

The following depicts the emission guidelines for existing fossil fuel-fired EGUs under Section EPA-111(d) and the BSER for each type of resource, beginning with existing CTs.

Figure 2: Guidelines for Existing Combustion Turbines[5]

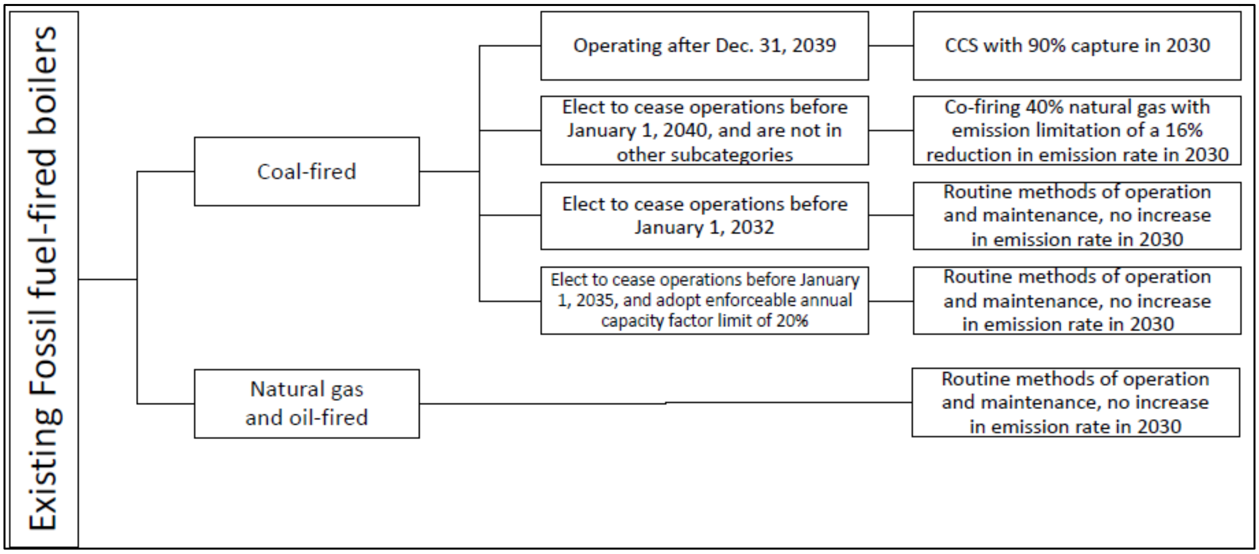


Existing CTs that are large and frequently used, defined as being greater than 300 megawatts ("MW") and operate at a capacity factor above 50%, have phased requirements and pathway options. These units can choose either a hydrogen or a CCS pathway. Under the hydrogen pathway, beginning in 2032 (Phase 1), Existing CTs must begin co-firing with a mixture of 30% low-GHG hydrogen and cannot produce more than 680 lbs. CO_2/MWh. Under the hydrogen pathway, beginning in 2038 (Phase 2), Existing CTs must increase to 96% co-firing using low-GHG hydrogen and produce no more than 90 lbs. CO_2/MWh. Under the CCS pathway, there is just a Phase 1 requirement, in which the Existing CTs must use CCS to capture 90% of the CO_2 emissions beginning in 2035. The EPA has not issued requirements for other smaller, less frequently used existing CTs, but it has solicited public comment for those resources.

The following depicts the emission guidelines for existing fossil fuel-fired boiler operated EGUs under EPA111(d) and the BSER for each type of resource.

[5] 111 Power Plants Stakeholder Presentation_Webinar June 2023.pdf, p. 17.

Figure 3: Guidelines for Existing Fossil Fuel-Fired Boilers[6]



For existing natural gas-fired boiler units, the EPA proposes the BSER to be routine methods of operation and maintenance with no increase in emissions (lbs. CO_2/MWh) beginning in 2030. For existing coal units, the BSER strategy depends on when the EGU owner commits to retire the unit. The BSER timing and strategy are indicated in Figure 3 above.

Despite the complex requirements, the EPA recognizes it is imperative the proposed emission guidelines should not cause reliability problems.[7] The EPA states the BSER options identified in the Proposed Rule are feasible and cost-effective options for the U.S. fleet of EGUs, and will provide sufficient operational flexibility and lead time to allow for smooth implementation of the Proposed Rule, and will not cause reliability problems.[8] However, until detailed engineering studies are performed for each of South Carolina's power plants that would support the use of these technologies, Kennedy remains unconvinced the Proposed Rule contains BSER options that are feasible, cost-effective and will not cause reliability problems.

Achieving these significant reductions will require an extreme overhaul of existing EGUs and significant adjustments to new resource plans. The Proposed Rule will complicate how the South Carolina electric utility industry is regulated. Resource planning will continue to be the focus of state regulatory authorities; however, the balance of least cost

[6] *Id.* at 18.
[7] *Id.*
[8] *Id.*

and customer affordability will be far overshadowed by the need to first meet federally mandated CO_2 emission goals.

Currently, utilities in the state of South Carolina must follow the statutory requirements of S.C. Code Ann. § 58-37-40 (“Section 40”), which established requirements for utilities to file Comprehensive Integrated Resource Plans (“IRPs”) every three years, with annual updates in the intervening years. Section 40 identifies the kinds of information that must be submitted as part of the IRP, establishes hearing requirements for the Comprehensive IRP, and provides factors that the South Carolina Public Service Commission (“SCPSC”) must consider in the IRP approval process.

The order in which factors are listed in Section 40, and that must be considered by the SCPSC are resource adequacy, consumer affordability and least cost, and compliance with applicable state and federal environmental regulations. Additional factors must be considered as well. However, the Proposed Rule will dominate the other factors that must be considered under South Carolina law. Utilities will be forced to conduct resource optimization analyses that will become significantly more complex to deal with different pathway decisions, evaluations that depend on capacity factors of existing and proposed generic resources, and constraints that will change over time.

Ignoring the changes that will have to be made to regulatory oversight, the Proposed Rule will increase the cost of electricity significantly, especially given there is little actual evidence of what the cost of hydrogen and CCS will be in the future. The EPA relies on the assumption that the cost of producing and transporting hydrogen fuel will become much lower by 2030 than it is today based on studies it has identified. However, as no hydrogen infrastructure currently exists at the scale required by the Proposed Rule, there is no way to know if the EPA’s estimates are even close to being accurate. The EPA also assumes it can forecast the future capital cost of CCS, even though no utility scale CCS projects exist at any EGUs in the U.S. today. Simply stated, the Proposed Rule relies heavily on unproven and untested technologies, which, if implemented, may ultimately lead to significant reliability problems.

The Proposed Rule follows the passage of the Inflation Reduction Act (“IRA”), which is already expected to greatly impact the electric utility industry. The IRA is expected to incentivize new technologies, increase renewable energy utilization, and decrease carbon emissions. The amount of carbon emissions reductions captured by the IRA alone are significant, and the incremental reductions resulting from the Proposed Rule are very small in comparison, but will come with significant additional risk, unknown cost to customers and extreme regulatory burdens for states including South Carolina.

The remainder of this Report focuses on the reasonableness of the EPA’s modeling of the Proposed Rule and the impacts of the Proposed Rule on South Carolina. In particular, the Report considers whether compliance is both realistic and achievable, and identifies key issues and concerns associated with the Proposed Rule. While the EPA evaluated both costs and benefits, Kennedy investigated the costs of EGU compliance with the Proposed Rule, as those are the impacts that affect electric utility customer bills and reliability.

II. Key Findings and Concerns

This section highlights the overall findings and outlines Kennedy's concerns with the EPA's modeling approach. The EPA conducted the analyses using ICF's Integrated Planning Model ("IPM"), the results of which are described in a 360-page report the EPA provided to stakeholders.[9] Other than the report, the EPA provided stakeholders a limited amount of input and output data for the brief review period the EPA permitted. In addition, the EPA provided another document that explained how the IPM model works, including how the IPM model makes resource selection decisions and performs production cost modeling analyses.[10]

The EPA's compliance analysis indicates there will be an increase in capital costs with some off-setting savings associated with avoided fixed and variable costs; however, the assumed savings may not materialize as the EPA expects.

In general, Kennedy determined the EPA over-estimated the feasibility of implementing the BSER technologies it assumes EGUs would be able to rely on to reduce carbon emissions. In doing so, the EPA understated the costs that would be incurred to meet the requirements based on the deadlines specified in the Proposed Rule. The EPA has not accounted for the significant expense of building out low-GHG hydrogen infrastructure, building pipelines (hydrogen, CO_2, natural gas), and building an extensive amount of transmission across the country. There are so many omissions in the EPA's analysis, that it is likely the EPA has understated the costs of compliance with the Proposed Rule by billions of dollars. Kennedy has not attempted to quantify these missing costs given the short amount of time the EPA allowed for comment. However, this Report quantifies some of the fuel related costs that are clearly missing from the EPA's analysis. The EPA should expand its analysis to account for the billions of dollars of costs that will be incurred to build out infrastructure to accommodate the requirements of the Proposed Rule.

In addition to the fact that the EPA has understated the costs of implementing the Proposed Rule, reliability problems will occur if large numbers of coal units retire too quickly, and natural gas units either are not built or are constrained to operate at low capacity factors due to unavailable and expensive BSER technologies. This rush to eliminate rotating generating assets can lead to grid instability problems. Coal fired steam turbines, and gas-fired turbines play a vital role in helping to maintain grid stability by providing inertia, and reactive power support. These units provide critical standby power when renewable resources operate intermittently, inertia, which helps to strengthen the grid and dampen fluctuations in frequency, and reactive power, which helps to maintain

[9] EPA-HQ-OAR-2023-0072-0007 Regulatory Impact Analysis.

[10] Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case.

voltage control. These ancillary services will be in high demand as more and more renewable resources come online. There are other technologies which can help provide similar reliability services, but the EPA did not account for any of the costs of implementing those technologies.

The following are specific issues of concern Kennedy identified.

1. EPA Understated the Costs of Compliance.

- **Hydrogen costs are understated.** The EPA noted its own modeling failed to quantify the increase in electricity demand required to produce hydrogen.[11] Also, the EPA did not sufficiently support the notion that hydrogen would only cost \$1/kg up to 2035, and \$0.5/kg thereafter, delivered to EGUs. At \$0.5/kg, hydrogen is priced at \$3.7/MBTU.

- **Potential new resource costs are understated.** Potential new resource cost assumptions the EPA used in the RIA are outdated and understated. Just as the EPA assumed natural gas prices would be higher as the demand for natural gas increases, likewise, the cost of solar resources would increase as the demand for solar resources increases. The data published by EPA used overly optimistic solar pricing given recent inflationary impacts, supply chain issues, and the fact that many solar developers have recently requested contract renegotiations, and/or contract termination based on solar component price increases.

- **The proposed 300 MW threshold for natural gas compliance has not been consistently applied.** The EPA aggregated generating units for modeling purposes, which has caused inconsistencies given that the Proposed Rule has a capacity size distinction (300 MW). As a result, the compliance options of some EGUs appear to have been modeled improperly. One example is the Columbia Energy Center ("CEC") owned by Dominion Energy South Carolina, Incorporated ("DESC"), which is an existing unit that the EPA assumed would not require a compliance action. However, it appears that, the DESC Columbia Energy Center would in fact be a candidate for a compliance action. Because the EPA did not model the need for compliance action at this and possibly other generating units, the costs the EPA identified in its analysis are understated.

- **CCS costs are likely understated**. The EPA used capital and operating cost assumptions derived by the engineering firm, Sargent & Lundy. Basic input and output documentation is provided; however, the data is not sufficient to assess

[11] *See* RIA, p. 3-34.

whether the modeled system would be cost effective, reliable, or even feasible, as CCS technology is not commercially used in the utility industry today.

- **Equilibrium pricing logic for natural gas and coal price forecasts should not be used.** Natural gas and coal price forecasts derived using equilibrium pricing logic is not appropriate, as it introduces different natural gas pricing assumptions in the Baseline and the Proposed Rule cases. Given the way the EPA conducted the modeling analyses, it is unclear whether differences in results between cases are due to requirements associated with the Proposed Rule or due to the changes in the fuel forecasts between the cases. Furthermore, if an equilibrium model is used for natural gas forecast prices, then such an analysis should be consistently performed for other costs such as renewable resource capital costs.

- **New source performance standards for natural gas resources may disproportionately impact the state of South Carolina.** South Carolina is part of the SERC East sub-region of the Southeast Reliability Corporation ("SERC"). SERC is responsible for developing and enforcing reliability standards in the region. The EPA's modeling shows that the SERC-East region is expected to add more new natural gas capacity than any other region modeled, and therefore NSPS for new natural gas may have a disproportionate impact on South Carolina compared to other regions/states. SERC reports that the SERC region overall and the SERC East region are expected to experience a significant amount of coal capacity retirements, 8,000[12] and 1,600[13] MW, respectively in the next ten years.

2. **The EPA Did Not Adequately Address Risks Related to Reliability.**

- **IPM modeling is not sufficiently detailed for state compliance analysis.** The EPA modeling was simplified in several ways, including the fact that model runs were only performed for seven years (2028, 2030, 2035, 2040, 2045, 2050, 2055); model runs were performed based on the North American Electric Reliability Corporation ("NERC") modeled regions; and individual units were aggregated so a fewer number of EGUs were evaluated. The number of years modeled are insufficient to capture the changes that will occur to the transitioning fleet of EGUs. Furthermore, aggregation of NERC regions and of individual units are too broad to measure the impact of changes on an individual state or utility.

- **IPM coal retirement assumptions presume the availability of replacement capacity.** The EPA's assumed coal unit retirement dates do not match publicly

[12] 2022-2031 SERC Annual Long Term Reliaiblity Assessment Report, p. 5, https://www.serc1.org/docs/default-source/program-areas/reliability-assessment/reliability-assessments/2022-2031-serc-annual-long-term-reliability-assessment-report.pdf

[13] *Id.* at 25.

available South Carolina IRP assumptions. While it is important to evaluate coal unit retirement dates based on economic considerations, current plans to retire coal plants in South Carolina are predicated on available replacement capacity, transmission investment, natural gas pipeline construction, and availability of renewable resources. Therefore, the IPM assumed retirement dates may not be achievable, given the normal physical limitations that are evaluated within the South Carolina utility planning process.

- **NERC regional modeling assumptions are inconsistent with South Carolina planning assumptions.** The EPA relied on the NERC Planning Reserve Margin assumption of a 15% reserve margin target; however, utilities in South Carolina plan to achieve individual targets that are higher than 15% based on winter peak load requirements. Additionally, the IPM modeling was not transparent, and it is unclear whether the EPA properly accounted for the quantity of operating reserves required for renewable resource integration, as well as the cost of the required operating reserves.

- **Renewable resource expansion plan results in South Carolina were questionable.** The IPM model delayed wind and solar additions in South Carolina in the Proposed Rule case compared to the Baseline Case, which is at odds with the objectives of the Proposed Rule, which purports to incentivize adoption of carbon-free resources and reduce carbon emissions.

- **A detailed reliability assessment should be carried out.** NERC performed an assessment of the EPA Clean Power Plan and identified reliability concerns. Before any new environmental regulation goes into effect, especially one as complex as the Proposed Rule, NERC should perform a detailed reliability assessment to evaluate the impacts of the Proposed Rule.

3. **EPA's Modeling is Based on Unproven and Unprecedented Assumptions for Technology and Market Readiness.**

- **Pipeline networks need to be developed, and transmission networks will require significant upgrades.** Significant investment in hydrogen, carbon sequestration, and natural gas pipeline networks will be required if the Proposed Rule is implemented. Furthermore, large investments in electric transmission and distribution network upgrades will also need to be made. The EPA did not account for these significant costs in the modeling analyses performed.

- **CCS and hydrogen technologies have not been widely demonstrated or proven cost effective.** CCS capital and hydrogen production costs are overly optimistic and not likely achievable in the time period required by the Proposed Rule.

- **The solar build trajectory is unreasonable.** Based on the EPA's modeling, South Carolina is expected to add an unprecedented amount of renewable resources over the study period. The EPA's Baseline case modeling shows South Carolina would have approximately 2,356 MW of wind and solar resources installed by 2028, which is not particularly unreasonable. However, the EPA's modeling indicates that renewable resources would increase to nearly 24,000 MW in the Baseline case and 28,000 MW in the Proposed Rule case by 2038. This increase will require a huge investment in renewable resources, a significant amount of land,[14] and a considerable amount of transmission upgrades.

- **Wind resource expansion plan additions are unrealistic.** The EPA's Proposed Rule case indicates that 8,042 MW of On-shore wind resources would need to be installed by 2038. Today, very few On-shore wind resources exist in the Southeast. Therefore, it is simply unrealistic for the EPA to expect that 8,042 MWs of On-Shore wind resources would be installed in South Carolina by 2038.

- **The IRA reduces carbon emissions effectively.** The IRA is expected to transform the renewable energy markets and incentivize additional investment in CCS and hydrogen technologies. The expectation is already accounted for in the EPA's Baseline Case and proves that a significant amount of CO_2 reductions is likely to be achieved without the need for any further federal emissions reduction requirements.

Three appendices are provided at the end of this report, and are explained as follows:

Appendix A contains responses to a subset of the EPA's 323 requests for feedback.

Appendix B contains a list of questions and requests for information to be produced about assumptions and documentation that was not readily available or transparent.

Appendix C contains a comparison of the Baseline case and Proposed Rule case expansion plan results on a South Carolina basis as produced by the EPA's IPM modeling analysis.

[14] Note that there is pending legislation in South Carolina that could to limit the amount of agricultural land that is converted for use by utility scale solar installations. (House Bill 3989, introduced on 2/16/23.)

III. Regulatory Impact Assessment

This section discusses the EPA's modeling results, which included potential benefits and costs, and projected emissions reductions if the Proposed Rule were implemented. On May 23, 2023, the EPA published an initial RIA analysis along with modeling results and workpapers, which is referred to in this report as the Initial RIA results. On July 7, 2023, the EPA published Revised RIA results, referred to as the Integrated RIA results.

A. Initial Regulatory Impact Analysis

The EPA's initial results ("initial analysis"), published on May 23, 2023, were not based on completely integrated analyses that reflected all of the Proposed Rule requirements in a single IPM production cost modeling run. The initial analysis captured a portion of the Proposed Rule requirements in the IPM production cost run, and the remaining requirements in a post-dispatch spreadsheet analysis. The Proposed Rule requirements that affected existing and new natural gas-fired combined cycle units, and that required co-firing using hydrogen beginning in 2035 were captured in a post-dispatch spreadsheet analysis.[15]

The EPA conducted three cases as part of the Initial RIA analysis: 1) a Less Stringent Rule Case , 2) the Proposed Rule case, and 3) a More Stringent Case. The three analyses were defined by the EPA as follows:

Less Stringent Case

NSPS - assumes imposition of the second phase of the NSPS in run year 2035.

Existing - assumes long-term existing coal-fired steam generating units greater than 700 MW, and plants greater than 2,000 MW are subject to 90 percent CCS requirements, while units less than 700 MW (and plants less than 2,000 MW) are subject to 40 percent natural gas co-firing requirements.

Proposed Rule Case

NSPS - assumes imposition of the second phase of the NSPS in run year 2035.

Existing - assumes all long-term existing coal-fired steam generating units are subject to 90 percent CCS requirements in 2030.

[15] RIA, p. ES-9.

More Stringent Case

NSPS - assumes imposition of the second phase of the NSPS in run year 2030.

Existing - assumes all long-term existing coal-fired steam generating units are subject to 90 percent CCS requirements in 2030.

To reduce modeling time, the EPA performed modeling runs for specific years, and mapped the results to other years to develop a full period analysis. The mapping is indicated in Figure 4 below:

Figure 4: Mapping of Model Years to Analysis Horizon Years

Modeled Year	Mapped Years
2028	2028
2030	2029 - 2031
2035	2032 - 2037
2040	2038 - 2042

The EPA's IPM modeling analysis derived the change in total production costs and emissions projected to comply with the Proposed Rule. To derive the change in production costs, the EPA derived a Baseline Case scenario that included impacts associated with the IRA, and the EPA modeled alternative cases that included the impacts of the Proposed Rule. IPM was used to solve for the least-cost approach to meet new regulatory requirements while also meeting fixed electricity demands, regulatory requirements, resource adequacy, and other constraints. The IPM modeling captured capital, fuel, operations and maintenance ("O&M"), and other costs, plus it included an estimate of costs associated with monitoring, reporting and recordkeeping ("MR&R") costs for both state entities and affected EGUs.[16]

Figure 5 below provides the results of the initial analysis the EPA performed. The results include the combination of the IPM results plus the EPA's post-dispatch spreadsheet results.[17] In addition to analyses based on alternative compliance requirements, the EPA evaluated results for low and high ends of a range based on different assumptions of how many existing plants would install CCS and how many EGUs would increase hydrogen co-firing.[18] The range of how many EGUs would comply using CCS versus redispatch

[16] RIA, p. 3-5 and EPA workpaper EPA-HQ-OAR-2023-0072-0008.
[17] The EPA's Initial RIA Report provides the IPM results in Table 3-7, and the post-dispatch spreadsheet results in Tables 8-5 and 8-6.
[18] Initial RIA analysis, p. ES-23.

was used and the analysis was not performed using an optimization model. The EPA performed the analysis in a post-dispatch spreadsheet model.

Figure 5: EPA's Initial Analysis - U.S. Compliance Costs

Estimated Changes in Compliance Cost Based on Three Estimates of Compliance Requirements And Assuming a Low and High Estimate of New Units Projected to Increase Hydrogen Co-firing (billions of 2019 dollars)						
	Low Estimate			High Estimate		
Year	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
2028	-0.21	-0.19	-0.07	-0.21	-0.19	-0.07
2030	4.06	4.08	3.02	4.06	4.08	3.02
3035	1.04	0.99	1.72	1.58	1.53	1.50
2040	1.50	1.45	1.43	2.17	2.12	2.08
2045	-0.05	-0.05	0.38	-0.05	-0.05	0.38

Based on the EPA's modeling approach, each year in Figure 5 was reproduced to represent a compliance period. The 2030 results are particularly curious as the cost impact in the More Stringent case appears to be lower than the cost impact in the Proposal and Less Stringent cases. [19] In addition, as will be discussed in more detail, the cost impacts of the Proposed Rule are understated.

B. Integrated Regulatory Impact Analysis

After publishing the Initial RIA results, the EPA published revised results ("Revised Analysis) on July 7, 2023, which reflected a fully integrated analysis, in which all compliance requirements were considered in the IPM modeling runs.[20] The results were published in a 32-page memo entitled, "Integrated Proposal Modeling and Updated Baseline Analysis."[21] On July 12, 2023, the EPA announced a limited extension to the public comment period, from July 24, 2023, to August 8, 2023. The deadlines have been challenging given the complexity of the Proposed Rule. The Revised Analysis primarily impacted the IPM results in 2035 and later years and affected existing and new natural gas-fired combined cycle ("CC") units that required co-firing using hydrogen beginning in 2035.

The EPA also conducted one other modeling scenario that incorporated higher liquified natural gas ("LNG") demand assumptions. The revised LNG assumptions were recently released by the Department of Energy ("DOE") in the 2023 Annual Energy Outlook ("AEO") Report and contained significantly higher assumptions regarding the demand for

[19] *See* Question 8 in Appendix B.

[20] US EPA. Memorandum to Docket EPA-HQ-OAR-2023-0072. Applicability of Emission Guidelines to Existing Stationary Combustion Turbines - FAQs. Prepared by EPA OAQPS. June 2023

[21] https://www.epa.gov/system/files/documents/2023-07/Integrated Proposal Modeling and Updated Baseline Analysis.pdf

exported LNG. For the revised analysis, the EPA did not analyze the Less Stringent and More Stringent cases, as it did in the Initial Analyses performed. Figure 6 compares cost estimates from the EPA's Revised Analysis compared to the Initial Analysis.

Figure 6: National Power Sector Compliance Estimates ($2019 Billions)

	Original RIA Proposed Case Low	**Original RIA Proposed Case High**	**Revised Analysis**	**Revised Analysis With LNG**
	Table 3-7 + Section 8 (low)	Table 3-7 + Section 8 (high)	Table 5	Table 15
2028	-0.21	-0.21	-0.22	-0.58
2030	4.06	4.06	4.04	3.30
2035	1.04	1.58	0.03	-0.95
2040	1.50	2.17	0.48	0.73
2045	-0.05	-0.05	N/A	N/A[22]

The 2030 and 2035 model years, which represent compliance years 2029-2037, show that the costs results are consistent between the Initial Analysis and the Revised Analysis. The LNG sensitivity case indicates an overall reduction in costs in all years before 2038.

Kennedy cannot validate the EPA's Initial or Revised results because the results the EPA provided in specific tables in the report (e.g., Table 3-7) do not match with the results found in IPM output files. The EPA should provide stakeholders additional workpaper support and ensure that workpapers are consistent with results in reports it provides.[23]

Kennedy derived South Carolina results from the workpapers that the EPA provided. Figure 7 contains the total cost estimates of the EPA Proposed Rule on a U.S. basis, and on a South Carolina basis, as derived from the IPM model output.

[22] Though the IPM run data was provided, the EPA only presented results for the Revised Analysis through 2040 in its tables 5 and 15.

[23] *See* Appendix B – Information Requests to EPA, question 1 regarding the attempted reconcilation.

Figure 7: Computed Power Sector Compliance Estimates ($2019 Billions)

	Integrated Model	Integrated Model (South Carolina) [24]
	computed	computed
2028	-0.24	-0.02
2030	3.90	0.11
2035	0.19	-0.09
2040	0.61	-0.01
2045	-0.18	-0.10
2050	0.43	-0.02
2055	0.53	-0.02

The EPA's results indicate that the Proposed Rule would lead to total cost increases in most years for the entire U.S, but for South Carolina, the results indicate that the Proposed Rule would result in total cost savings in each modeled year except 2030. Not only are the results between the U.S. and South Carolina inconsistent, but the results are also unrealistic in indicating that South Carolina would incur lower costs if the Proposed Rule were implemented.

C. Compliance Modeling

1. Existing Resources and Retrofit Options

Although analyses were performed for the entire U.S., the EPA also provided results on a state-by-state basis, and Kennedy specifically focused on the EPA results that affected the major electric utilities in South Carolina and their EGUs. The major electric utilities in South Carolina include DESC, the South Carolina Public Service Authority ("Santee Cooper"), Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP"). To assist in this process, Kennedy utilized information that the South Carolina utilities provided, which is referred to as the "Utility Generating Unit Inventory" (the "Inventory") survey. The Inventory contains a high-level assessment of the resources that the utilities assume would be impacted by the Proposed Rule. Figures 8 and 9 below identify the coal and natural gas units owned by the utilities and identify the amount of MWs the utilities assume would be impacted by the Proposed Rule.

[24] RPE files, exlcuding Canada and fields without a resource type or that are associated with Retirement. MR&R for the U.S., is consistent with the workpaper provided by EPA. For South Carolina, this is taken 1/50 share as an approximate assignment to the state.

Figure 8: Existing South Carolina Generating Unit Inventory Summary (Coal)

Plant (Utility) – Coal	Total MW	MW impacted
Wateree (DESC)	772	772
Williams (DESC)	660	660
Winyah (Santee Cooper)	1260	1260
Cross (Santee Cooper)	2390	2390
Total	**5,082**	**5,082**

Figure 9: Existing South Carolina Generating Unit Inventory Summary (Natural Gas)

Plant (Utility) – Natural Gas	Total MW	MW impacted
Bushy Park CT (DESC)	50	
Coit CT (DESC)	36	
Columbia Energy Center "CEC" CC (DESC)	669	394
Cope Steam Turbine (DESC)	417	417
Hagood CT (DESC)	177	
Jasper CC (DESC)	1,068	1,068
McMeekin Steam Turbine (DESC)	294	294
Parr CT (DESC)	100	
Urquhart CT/CC (DESC)	759	100
Mill Creek CT (DEC)	799	
W S Lee CT/CC (DEC)	955	847
Darlington County CT (DEP)	316	
John S Rainey CT/CC (Santee Cooper)	1,102	
Total	**6,742**	**3,120**

Overall, approximately 70% of the South Carolina fleet (by MW) of EGUs may be impacted by the Proposed Rule. Kennedy compared the utility assumptions with the EPA assumptions used in the IPM modeling process.

IPM required a database containing information about existing and planned EGUs from across the U.S. The EPA developed a national database referred to as the National Electric Energy Data System ("NEEDS") that was generated from EIA Form 860 data and the EPA's Emissions Tracking System ("ETS"), as adjusted based on comments received and announcements.[25] The EPA then used an algorithm to reduce, or aggregate, the nearly 24,000 units that were in the database down to the approximately 4,000 units that

[25] IPM documentation, Section 4.2.

were used in IPM.[26] While the EPA generally described the process used to aggregate the generating units, it is unclear whether the aggregation process and workpapers were actually provided by the EPA for public review and comment.

Coal Unit Modeling

To review the reasonableness and compliance decisions of the EPA's Initial and Revised analyses for South Carolina units, Kennedy attempted to map the IPM input assumptions and output results to the NEEDS database. The mapping process was performed by comparing generating unit information including fuel type, capacity, and heat rates in the NEEDS database to information derived by IPM in output results files (.RPE files).[27]

The EPA described the costs that were modeled in IPM as follows:

> In EPA Platform v6, the cost and performance characteristics of an existing unit are determined by the unit's heat rates, emission rates, variable operation, and maintenance cost (VOM), and fixed operation and maintenance costs (FOM). For existing units, only the cost of maintaining (FOM) and running (VOM) the unit are modeled because capital costs and all related carrying capital charges are sunk, and hence, economically irrelevant for projecting least-cost investment and operational decisions going forward.[28]

Regarding FOM assumptions, the EPA stated that FERC Form 1 data and plant statistics maintained by SNL Energy and ICF were used to derive the input data.[29] Figure 10 identifies some of the assumptions modeled for the Wateree Station in South Carolina, which is owned by DESC. The information was found in the IPM input data file (.DAT file), and the data shows the compliance options IPM evaluated for the plant during the study period.

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[26] EPA states that it uses 11 categories for aggregating the EPA Platform v6: Facility (ORIS) for fossil w/o CT units <= 25 MW, Model Region, State, Unit Technology Type, Unit Configuration, Cogen, Fuel Category, Fuel Demand Region, Applicable Environmental Regulations, Heat Rates, Size. (Section 4 of the IPM v6 documentation)
[27] A translation from NEEDS to IPM would be a helpful document to provide reviewers. *See* Question 2 of the Appendix B information requests to the EPA on mapping of NEEDs to IPM
[28] IPM Manual, p. 4-9.
[29] *Id.* at 4-11.

Figure 10: Unit 2590 (Wateree)
Illustrative Coal Unit – Revised Analysis Proposed Rule Case Input Mapping

	Continued Operation	Coal to Gas [30]	CCS [31]	Retire [32]
Example Unit ID	2590	9493	46308 [33]	9494 [34]
Online year		2023	2030	various
Capacity	342 MW	342 MW	233.6 MW (-31.7%)	N/A
Heat Rate	10,329	10,845 +5% penalty	15,124	N/A
Capital Cost ($/kW)	0	252 Cyclone[35]	2,329	N/A
Fixed O&M (FOM) $/kW-yr	56	37.5 -33% existing	90 (+34)	N/A
Variable O&M (VOM) $/MWh [36]		-25%		N/A

For Wateree, the EPA indicated that it considered using CCS, Coal to Gas Conversion, and Heat Rate Improvement retrofit options in IPM.[37] Despite the documentation stating that heat rate improvements were considered as compliance options, it is unclear that option was actually modeled by IPM.[38] Furthermore, the EPA did not provide unit-level summary reports as part of the workpapers, which made the review of the modeling logic and assumptions difficult.

Figure 11 compares EPA assumptions in the IPM Baseline and Integrated Proposed Rule Cases, and compares those assumptions to the utilities' own assumptions regarding coal unit retirement dates.

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30 *See* Section 5.7, table 5-18 of IPM Documentation.
31 *See* Section 6.1.1, table 6-1 of IPM Documentation.
32 *See* also Unit ID:13691, 36306 that appear to be be prerequisite operational units with costs and heat rate penalties for online year 2023 before retirement in 2023. It is unclear how these units are utilized in the expansion plan analysis. *See* Appendix B, question 6.
33 *See* also unit IDs: 46098, 46413.
34 *See* also unit IDs: 13690, 19276, 39916, 42082, 46518, 46728, 46833.
35 252 $/kW derived as 427*(75/342)^0.35 as described in Table 5-18 of IPM Documentation.
36 Variable O&M costs do not appear for the units within the .DAT file. Assumed as mills/kWh, but represented in table as $/MWh. See question 3 in Appendix B.
37 *See* Section 5, Table 5-1 of IPM Documentation.
38 Heat Rate Improvement Method Costs and Limitations Memo Document ID: EPA-HQ-OAR-2023-0072-0018, includes discussion stating, "While multiple HRI methods mentioned above can potentially be installed on the same unit in tandem, the HRI that can be realized may not be truly additive. Typically for HRI evaluations, it is necessary to perform a site-specific investigation for each coal-fired EGU to determine which HRI methods are applicable, the achievable HRI, and the costs."

Figure 11: IPM vs. Utility Assumptions
Assumed Coal Retirement Dates – Revised Analysis Cases

	EPA Modeling [39]		Utility
Unit	**Baseline Case**	**Proposed Rule Case**	**EGU Inventory**
DESC Wateree	2028	2028	Dec 2028
DESC Williams	2028	2028	Dec 2030
Santee Cooper Cross	2045	2030	N/A
Santee Cooper Winyah	2030	2030	Dec 2030

The EPA's Baseline Case assumptions are nearly the same as the South Carolina Utilities' Inventory assumptions, with two exceptions. DESC expects to retire Williams by 2030, and Santee Cooper has not selected a specific retirement date for the Cross plant. In Santee Cooper's 2023 IRP pending before the SCPSC, Cross was assumed to have a retirement date of 2052 in the Company's Preferred IRP Plan.[40]

There is an additional nuance to the South Carolina utilities' coal retirement decision-making process that the EPA's modeling analysis does not address. The utilities identified their current assumptions for retirement dates in the Inventory they supplied, but in their IRP Reports, the utilities note that customers could be exposed to risks if suitable replacement capacity is not available at the time the coal units are retired. In addition, the utilities note that retirements are also contingent on being able to make necessary transmission upgrades and building natural gas pipelines.

New resource additions require large capital investments, regulatory approvals, major planning studies, complex transmission analyses, permitting approval processes, manpower availability, and construction efforts, which can take six to eight years to perform, and there are limits to the number of simultaneous projects that can be performed. In the case of Williams and Winyah, owned by DESC and Santee Cooper, respectively, both utilities decided to implement Effluent Limitations Guidelines ("ELG") upgrades in order to maintain the existing capacity in recognition of the risks associated with acquiring suitable replacement capacity by 2028. Each utility stated that while they

[39] Original EPA Modeling and Integrated Modeling appear to reflect the same selections for coal unit retirement dates.
[40] Santee Cooper 2023 IRP, May 15, 2023, https://dms.psc.sc.gov/Attachments/Matter/89ae68ac-b61b-470d-81cc-4f9589a28f9a

are now planning to shut down the units in 2030, it is possible they may need to delay retirement beyond 2030. As the EPA rule is written currently, no such “safety valve” exists to allow utilities the flexibility to continue to operate the units if reliability risks are identified.[41] The Proposed Rule does not include sufficient flexibility given the risks that utilities face in having to ensure the reliability of supply for their customers.

Gas Unit Modeling

The EPA assumed the cost to operate existing natural gas units in IPM. Figure 12 describes some of the key modeling assumptions that influence the decisions IPM considers related to natural gas units. Figure 12 also provides illustrative compliance options for a sample natural gas unit, DESC’s CEC CC plant.

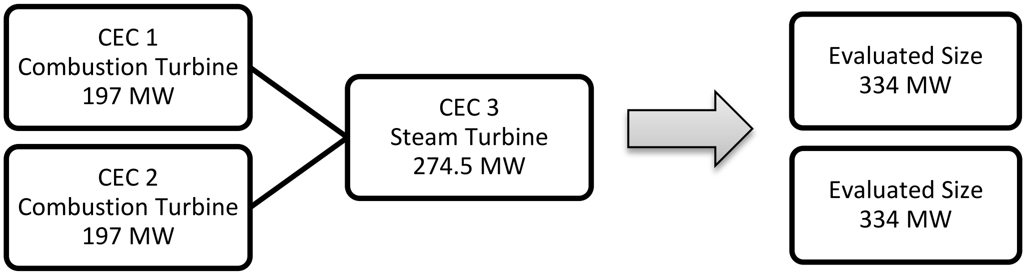
Figure 12: Unit 1945 (Columbia Energy Center)
Illustrative Gas Unit - Integrated Proposal Input Mapping

	Continued Operation	Hydrogen Retrofit	Hydrogen Retrofit Undone	CCS [42]	Retire
Example Unit ID	1945	56589	57201	7520 [43]	7517 [44]
Online year	2004	2004	2004	2030	various
Capacity	543 MW	543 MW	543 MW	475 MW 12.5% penalty	N/A
Heat Rate	5,757	5757	5757	6,582 14.3% penalty	N/A
Capital Cost $/kW	0	.01	.02	831	N/A
Fixed O&M (FOM) $/kW-yr	31.6	31.6 No adj.	31.6 No adj.	45.3 (Increase 13.7)	N/A
Variable O&M (VOM)[45]	$2.29 /MWh	$2.29 /MWh	$2.29 /MWh	$2.29 /MWh	N/A

CEC is a 2x1 CC unit which has 2 CTs and one steam turbine unit. Figure 13 shows the capacity associated with each turbine unit, which in total sums to 668.5 MW (nameplate). This data was supplied by DESC in the Inventory, and DESC provided the data for nameplate, summer, and winter ratings.

[41] For example, see Dominion Energy South Carolina’s 2023 Integrated Resource Plan, January 24, 2023, p. 32. Dominion Energy South Carolina’s 2023 Integrated Resource Plan.
[42] *See* Section 6.1.1, table 6-1 of IPM Documentation.
[43] *See* also unit IDs: 750, 7521, 7518
[44] *See* also unit IDs: 7517, 57813, 59037, 51260, 51261, 51258.
[45] Variable O&M costs do not appear for the units within the .DAT file, however there is a VOM rate in the output assumed for this table. See Question 4 in Appendix B below.

Figure 13: CEC Nameplate Capacity



The EPA provided clarification on July 7 that described how to evaluate the size of CC units such as CEC. Per the EPA's Memo, the steam turbine capacity should be allocated equally between the two CTs, and then an assessment should be made whether the two CTs exceed the 300 MW threshold; however, the EPA did not mention which capacity ratings should be used.[46] Based on the nameplate rating data DESC supplied, the EPA's calculation implies that each of the CEC CT's is 334 MW in size (197 + .5 (274.5) = 334 MW), which exceeds the 300 MW threshold limit, and therefore, means that CEC would have to comply with the Proposed Rule. If DESC's winter ratings were used, in which CT1 and CT2 are rated 192.1 MW and 169.0 MW, respectively, and the steam turbine is rated at 259.6 MW, then CT1 would have to comply (.5 * 259.6 + 192.1 = 321.9 MW), but CT2 would not have to comply (.5 * 259.6 + 169.0 = 298.8 MW).

The EPA did not clearly state whether winter capacity or summer capacity ratings should be used, but it appears the IPM modeling used summer capacity ratings, though DESC is a winter peaking utility. The IPM model showed CEC as 543 MW, implying it has two 151.5 MW CTs and a 240 MW steam turbine. This led to the determination that CEC would not have to comply at all (.5 * 240 + 151.5 = 271.5 MW < 300 MW). The lack of clarity and interpretation may have resulted in an understated cost of compliance, if in fact, CEC and other units like it would be required to comply with the Proposed Rule.[47]

The following Figure 14 describes data from the natural gas CC unit Inventory provided by utilities in South Carolina compared to the NEEDs data and Kennedy's assumed mapping to the output.

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[46] U.S. EPA. Memorandum to Docket EPA-HQ-OAR-2023-0072. Applicability of Emission Guidelines to Existing Stationary Combustion Turbines - FAQs. Prepared by EPA OAQPS. June 2023.
[47] *See* Question 3 of Appendix B.

Figure 14: Combined Cycle Capacity Comparison (MW)

Plant Name	Generating Unit Inventory Capacity			NEEDS	Aggregated for IPM	IPM Unit ID
	Nameplate	Summer	Winter			
W S Lee	242.3	237	248	237	786	1953
	242.3	236	248	236		
	362.1	313	313	313		
Urquhart CC	75	64	65	64	458	1948
	75	64	66	64		
	198.9	162	177	162		
	198.9	168	176	168		
Columbia Energy Center	197	142	192.1	151.5	543	1945
	197	142	169	151.5		
	274.5	235	259.6	240		
Jasper	212.8	170	184	156	852	1947
	198.9	173	190	164		
	212.8	170	185	147		
	443.7	390	402	385		
John S Rainey	165	150	170	150	460	1946
	165	150	170	150		
	190	160	190	160		
Cherokee Cogen[48]	60	51	66	51	86	1954
	41.2	35	35	35		

Depending on size and capacity factor, compliance with the Proposed Rule would require CC units to either co-fire with hydrogen, install CCS, or operate as lower capacity factor units.

Of the six CC units described in Figure 14, Lee would be required to comply based on an evaluated size greater than 300 MW. CEC and Jasper may or may not have to comply depending on the capacity ratings used. Urquhart, Rainey, and Cherokee would not be required to comply as the evaluated capacities of those units are below 300 MW.[49]

Figure 15 describes the capacity factors as modeled in the Proposed Rule case. The figure indicates that Jasper and CEC are expected to operate above 50%, and if these

[48] Santee Cooper has filed for approval of the acquisition of Cherokee Cogen CC in SC Docket 2023-189-E and states that it is 98 MW. The unit was not included in the Generating Unit Inventory provided to ORS, so values included here are from EIA-860, 2022 Early Release.

[49] Unit IDs 56589, 56590, 56591, 56592, 56597, and 56598, for CEC, Rainey, Jasper, Urquhart, Lee, and Cherokee respectively.

units are required to comply, the IPM modeling understated the cost to South Carolina of compliance with the Proposed Rule.

Figure 15: Capacity Factors at Existing Natural Gas CC Units

Unit	MW	Unit ID	2028	2030	2035	2040	2045	2050
CEC	543	1945	85%	85%	85%	85%	85%	74%
Rainey	460	1946	45%	78%	78%	85%	67%	67%
Jasper	852	1947	40%	78%	72%	67%	67%	60%
Urquhart	458	1948	21%	54%	56%	16%	20%	14%
Lee	784	1953, 58433	72%	85%	50%	50%	50%	50%
Cherokee	86	1954	22%	78%	63%	18%	20%	14%

2. Generic Resources and Solar Pricing

The conventional resource options modeled in IPM were sourced from the EIA AEO 2021 Report, and some of the renewable energy pricing was sourced from the National Renewable Energy Laboratory's ("NREL") 2021 Annual Technology Baseline ("ATB") moderate case.[50] Solar resource input assumptions included capital costs and FOM assumptions, and the resulting costs can be approximated to a $/MWh energy-based cost.

Figure 16 shows the costs derived by Kennedy for new solar resources assigned to South Carolina, sourced from data from the IPM revised case output results. The IPM modeling analyses were performed and results were reported using 2019 real dollars. Figure 16 shows the values in both 2019 dollars and in nominal dollars based on a conversion using the EPA's assumed discount rate. The results indicated in nominal dollars highlight the fact the EPA assumptions reflect the expectation that the cost of solar resources will decline significantly on a nominal cost basis between the 2028/2030 time period and the 2035/2040 time period.

Figure 16: Illustrative New South Carolina Solar Nominal Solar Pricing ($/MWh)

	2028	2030	2035	2040
Unit ID	24889	24889	24910	24931
$/MWh (2019$)	23.88	23.88	15.77	13.48
Convert to Nominal Dollars ($/MWh) Conversion (@ 3.76%)	33.29	35.84	28.46	29.27

The assumptions regarding solar costs are outdated and too low as inflation has dramatically increased the costs experienced by solar developers in recent years, and

50 *See* tables 4-12 and 4-15 in the IPM Documentation for assumptions and characteristics.

the EPA's modeling is based on costs from 2021. Utilities all over the country have encountered challenges in developing solar projects due to supply chain issues, U.S. trade policy, and general inflationary trends. In South Carolina, Santee Cooper explained in its 2023 IRP that five recently signed power purchase agreements ("PPAs") have either been cancelled or the prices have been renegotiated. Santee Cooper's 2023 IRP stated:

> Due to recent challenges faced by the solar industry, the project developers notified Santee Cooper and Central that the projects could not be completed at the agreed-upon prices and schedules as reflected in the PPAs. One of the project developers terminated its PPAs with Santee Cooper and Central for one 75 MW project, and Santee Cooper and Central have agreed to amend the PPAs with another project developer for two 100 MW projects. As of the timing of this report, Santee Cooper and Central are involved in discussions with the other two project developers to understand the challenges specific to each of the two remaining 75 MW projects and to evaluate measures to take related to their PPAs.[51]

It is also reasonable to expect the IRA and the Proposed Rule will lead to a significant increase in demand for renewable resources such as solar, which will increase the cost of solar resources beyond what the EPA projected in the IPM analysis. Therefore, the EPA modeling analysis understated the compliance costs for solar resources.

3. Regional versus Utility Modeling

Reserve Margin

In reviewing the EPA's IPM model, Kennedy questions whether the IPM model, which aggregates resources in the NERC SERC region covering primarily North and South Carolina (referred to in IPM as "S_VACAR"[52]), used assumptions and produced dispatch results consistent with actual experience in South Carolina. For example, the EPA assumed a 15% target reserve margin assumption for summer and winter modeling for the S_VACAR Region (720).[53] This is lower than what the South Carolina utilities assume in their resource planning studies to ensure reliability, especially during winter periods, as South Carolina's utilities are winter peaking. DESC plans to a 20.1% winter target reserve

[51] Santee Cooper 2023 IRP, May 15, 2023, p 48, https://dms.psc.sc.gov/Attachments/Matter/89ae68ac-b61b-470d-81cc-4f9589a28f9a

[52] The IPM Model referred to the SERC region that South Carolina is in as S_VACAR; however, in reality South Carolina is part ol the SERC East subregion of SERC, which includes primarily South Carolina and North Carolina. While the labeling caused some confusion, the states included in S_VACAR in IPM were consistent with SERC East.

[53] Table 3-9 Planning Reserve Margins in IPM manual.

margin, and Santee Cooper and Duke both plan to a 17% target.[54] The EPA's lower target reserve margin assumption in IPM would not result in adequate capacity being planned to meet reliability requirements. Therefore, the EPA's estimate of the costs of compliance with the Proposed Rule are understated.

Operating Reserves

Figure 17 provides a comparison of the IPM Operating Reserve Requirements compared to those modeled by DESC in its 2023 IRP.

Figure 17: Operating Reserve Requirement Comparison

	IPM Modeled [55]	DESC 2023 IRP [56]
Additional Reserve Requirements for Renewable Energy	10% of wind capacity (flex) .5% of wind capacity (reg) 4% of solar capacity (flex) .3% of solar capacity (reg)	For wind and solar: 35% of capacity (contingency) 10% of capacity (reg)

DESC requires considerably more operating reserves to integrate renewable resources than the EPA's IPM model assumed. Given the significant amount of additional renewable resources expected to be added for compliance with the Proposed Rule, the EPA has greatly understated the integration costs associated with adding more renewable resources in South Carolina.

Assigned Renewable Capacity

In modeling the expansion plan for the S VACAR region, the IPM regional results are allocated to the states for reporting purposes. As shown in Figure 18, it appears that in the assignment of resources to states, the amount of renewable energy for South Carolina fluctuates between the Baseline and Integrated Proposed Rule cases, compared to the amounts of renewable energy for North Carolina.[57]

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54 DESC 2023 IRP Report p 51; Santee Cooper 2023 IRP Report p 73; Duke 2022 IRPs, Chapter 6 p. 2 (DEP 2022 Update and DEC 2022 Update).
55 Table 3-10 Operating Reserve Requirement Assumptions by Type in v6 in IPM manual.
56 2023-9-E ORS AIR 1-23 (e).
57 IPM modeled renewable energy target requirements for NC, as shown in Table 3-18 in IPM documentation.

Figure 18: Comparison of Renewable Energy Baseline vs. Proposal (S_VACAR) MW

	Capacity Type	UPDATED BASELINE 2028	2030	2035	2040	INTEGRATED PROPOSAL 2028	2030	2035	2040	DELTA 2028	2030	2035	2040
NC	00 Exist Solar PV	3,432	3,432	3,432	3,432	3,432	3,432	3,432	3,432	-	-	-	-
	00 New Onshore Wind	-	3,787	3,787	3,787	-	3,787	3,787	3,787	-	-	-	-
	00 New Solar PV	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	-	-	-	-
SC	00 Exist Solar PV	724	724	724	724	724	724	724	724	-	-	-	-
	00 New Onshore Wind	-	2,990	5,999	6,275	-	587	5,999	8,042	-	(2,403)	-	1,767
	00 New Solar PV	1,784	1,784	5,722	16,794	1,784	1,784	2,430	18,481	-	-	(3,292)	1,687

The delay in the amount of wind and solar resources added in the Proposed Rule case is counterintuitive, particularly if it is the intention of the Proposed Rule to incentivize the adoption of carbon-free resources and reduce carbon emissions. Furthermore, it is very strange that so much renewable capacity would be added in South Carolina between 2035 and 2040, which reflects a huge jump in solar capacity in a short period of time.

4. Commodity Pricing

The IPM model includes equilibrium pricing logic to derive natural gas and coal price forecasts based on supply and demand constraints that are assumed to be consistent with the specific modeled scenarios. Few and possibly no utilities perform resource planning analyses assuming different future scenarios that warrant the use of different natural gas and coal price forecasts. Generally, utility studies attempt to determine impacts of specific modeling changes and require other input assumptions to remain constant so that the impact of the specific modeling changes can be evaluated. In the case of the EPA's modeling, evaluation of the impacts attributed to the Proposed Rule are difficult to determine because the EPA also reduced the coal and natural gas price forecasts at the same time. Kennedy examined the impact of using different gas price forecasts and found that using consistent natural gas price forecasts in both the Baseline and Proposed Rule cases could add $81 million to South Carolina's compliance costs over the 2028-2042 study period.

Also, if it is necessary to use equilibrium pricing modeling logic for natural gas and coal price forecasts, then the EPA should have also used equilibrium pricing modeling logic for renewable resource capital and O&M price forecasts. This is because increased demand for renewable resources should drive up the cost of those resources. Santee Cooper's recent experience with solar projects discussed earlier in this Report shows that increased costs for solar projects is a reasonable expectation.

Furthermore, for the same reason, the EPA should have also used equilibrium pricing modeling logic for hydrogen, especially given the large increase in demand for hydrogen the EPA assumes will occur as a result of the Proposed Rule. The EPA's assumptions regarding hydrogen cost modeling are detailed below which indicates the EPA ignored certain impacts in evaluating the cost of the Proposed Rule.

> Currently, hydrogen is an exogenous input to the model, represented as a fuel that is available at affected sources at a delivered cost of $1/kg under the baseline, and at a delivered cost of $0.5/kg in years when the second phase of the NSPS is assumed to be active. The model does not track any upstream emissions associated with the production of the hydrogen, nor any incremental electricity demand associated with its production. The incorporation of these effects could change the amount of hydrogen selected as a compliance measure. The model also does not account for any possible increases in NOX emission rates at higher levels of hydrogen blending.[58]

At $.5/kg, the price of hydrogen equates to $3.7/MBTU (2019$) on a dollars per MBTU basis. The EPA explained further "[u]nder the illustrative Proposal scenario, incremental energy requirements to produce hydrogen in 2035 is estimated to be about 108 TWh, or approximately 2 percent of the total projected nationwide electric generation."[59]

If the energy to produce hydrogen has been unaccounted for in South Carolina based on the EPA's explanation above, a 2% increase in South Carolina energy requirements could add nearly 2,584 GWh to South Carolina's energy requirements in a year. At an estimated cost of $30.16/MWh, the reported wholesale electricity price in 2035, that could mean that South Carolina would incur an additional $78 million a year in generating costs in the Proposed Rule case. This could add $468 million to the EPA's estimate over the 6 years that hydrogen was utilized in South Carolina in the Proposed Rule case.

Also, the hydrogen price forecast appears to be understated in the EPA's IPM modeling. The EPA states its modeling assumes hydrogen forecast costs are between $0.5/kg to $1.0/kg, and the EPA acknowledged the costs it used were even lower than the DOE's estimate of hydrogen costs for 2030 of $0.70/kg to $1.15/kg.[60] Additionally, the International Energy Agency ("IEA") reported in its Global Hydrogen Review:

> Our analysis suggests that with today's fossil energy prices, renewable hydrogen could already compete with hydrogen from fossil fuels in many regions, especially those with good renewable resources and that must import fossil fuels to meet demand for hydrogen production. There is of

[58] *See* RIA, p. 3-34.
[59] *Id.* p. 3-13.
[60] *See* RIA, p. 3-12, and footnote 73 referencing the DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023

> course uncertainty about how this plays out over the next few years. But if electrolyser projects in the pipeline are realised and the planned scale-up in manufacturing capacities takes place, costs for electrolysers could fall by around 70% by 2030 compared to today. Combined with the expected drop in the cost of renewable energy, this can bring the cost of renewable-based hydrogen down to a range for USD 1.3-4.5/kg H2 (equivalent to USD 39-135/MWh). The lower end of this range is in regions with good access to renewable energy where renewable hydrogen could already be structurally competitive with unabated fossil fuels.[61]

It is evident the hydrogen pricing used by the EPA analyses is overly optimistic, and premised on expected advancements in manufacturing capacity, which has not yet been proven at the scale required by the EPA's Proposed Rule case. Additional hydrogen demand may materialize as a result of the incentives included in the IRA, but the extent of how much will result in lower hydrogen prices is completely unknown today.

Furthermore, the above discussion has only accounted for the cost of producing hydrogen; it has not considered the total cost of building out the infrastructure necessary to transport hydrogen to the EGUs and being able to store hydrogen as necessary. Because of the limited amount of time that the EPA has allowed for evaluating the Proposed Rule, stakeholders have simply not had enough time to fully vet all of the costs associated with utilizing hydrogen in EGUs. This could add billions of dollars to the cost of complying with the EPA's Proposed Rule.

It is interesting that the EPA's modeling results for the U.S. determined that hydrogen generation would increase dramatically by 2035 and would then nearly be eliminated five years later in the Proposed Rule case. The following Figure 19 shows hydrogen generation is largely confined to just the 2035 model run year, which only was used for a six-year portion of the projected modeling period (2032-2037). The Figure shows that in the Proposed Rule case, in the 2035 model run year, hydrogen usage was assumed to occur in only twenty-one (21) states, and in the 2040 model run year, it was only used in three states.[62]

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[61] https://www.iea.org/reports/global-hydrogen-review-2022/executive-summary

[62] Results derived from the Integrated Proposal IPM Output (.RPE).

Figure 19: Hydrogen Fuel GWH by State by Model Year

State	2035	2040
Alabama	1,301	
California	32,446	36,856
Colorado	441	
Connecticut	3,223	2,260
Florida	2,782	
Georgia	2,225	
Idaho	796	
Indiana	144	
Kentucky	3,181	
Massachusetts	2,740	
Michigan	1,121	
New Hampshire	897	
New York	145	
North Carolina	4,501	
Ohio	6,315	
Oregon	2,923	2,923
Pennsylvania	7,052	
South Carolina	3,367	
Utah	2,192	
Virginia	1,185	
West Virginia	152	
Total GWh	**79,129**	**42,040**

It is unreasonable to assume a hydrogen economy will materialize to support the Proposed Rule, and yet the EPA's modeling shows actual utilization will only occur in three states by 2040.

Additionally, there was a discrepancy between the EPA's July 7 Updated Modeling Analysis Report and the results actually found in the IPM modeling output database. The EPA's July 7 Updated Modeling Analysis report indicated that in 2035, 238,000 GWH of hydrogen would be produced in 2035 in the Proposed Rule Case, not 79,129 GWh, which was found in the IPM modeling output database.[63] However, the July 7 Updated Modeling Analysis Report and the IPM modeling output database reported consistent results in 2040 (42,040 GWh) for 2040.

It appears the reason there is a reduction in the amount of hydrogen usage by 2040 that relates to the fact that the EPA is allowing EGUs the flexibility to stop co-firing using hydrogen to "better capture emissions rate requirements as a function of annual capacity

[63] *See* Appendix B, item 10.

factor," which appears extensively in the EPA's IPM modeling.[64] However, the EPA's modeling raises questions about how long-term investments in the hydrogen market could possibly be made if hydrogen usage declines so dramatically over time.

State public service commissions will be hesitant to approve capital investments in hydrogen retrofit technologies that will only be used for a six or seven year period. In the utilities industry, the "Used and Useful Principle" is a concept that requires energy assets to be physically used and useful to current ratepayers before those ratepayers are asked to pay the associated costs. Normally, generation assets are depreciated over a long-term horizon (20 to 40 years) to spread out customer costs over the entire operating lives of the assets. In the case of hydrogen investment, assets would have to be recovered over just a six or seven year period, which would make the costs of those assets significantly more expensive than the EPA has assumed.

5. NSPS and New Natural Gas Capacity

The IPM modeling results indicated that South Carolina's region (S_VACAR and also referred to as SERC_VACAR in IPM's modeling) may construct approximately 7,500 MW of new CC capacity, which is the largest amount of CC capacity expected to be constructed in any of the modeled regions. The following Figure 20 shows the amount of CC capacity added in different regions of the country in the Proposed Rule case for 2035.

[64] Integrated Proposal Modeling and Updated Baseline Analysis memo, p. 5.

Figure 20: Combined Cycle Capacity by Region 2035 (Integrated Proposal)

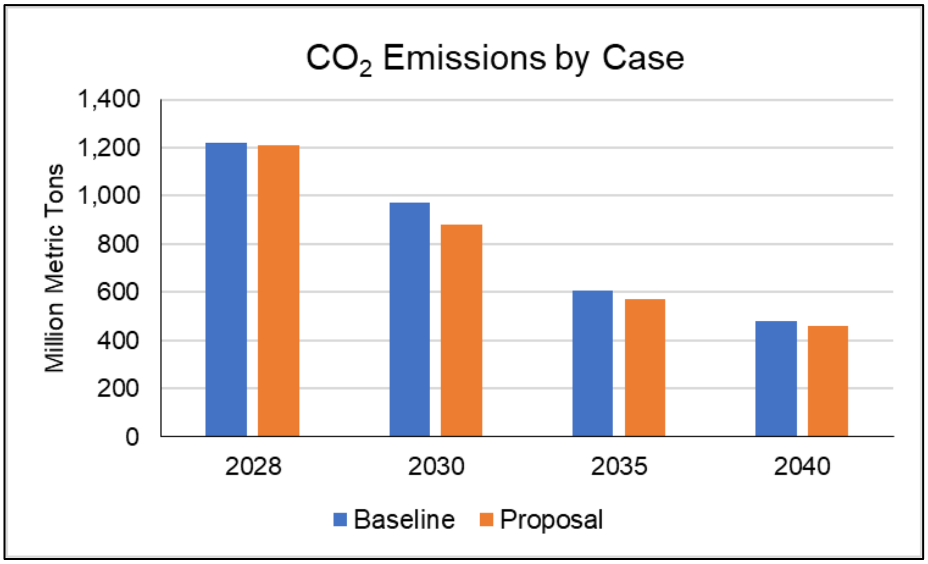
Region	New CC	New CC w/ CCS	New CC w CF limit	New CC with Hydrogen Retrofit	Total	Total %
FRCC	38	-	-	2,808	2,846	
MISO_Amite South	(0)	1,004	-	-	1,004	7%
MISO_Louisiana	114	1,827	-	-	1,942	5%
MISO_Lower Michigan	1,555	206	-	-	1,761	4%
MISO_WOTAB	2	-	998	-	1,000	3%
PJM West	4	-	485	3,797	4,286	
PJM_AP	2	-	-	617	619	2%
PJM_ATSI	-	-	-	5,115	5,115	13%
PJM_ComEd	2	-	2,412	-	2,414	6%
PJM_EMAAC	42	-	-	-	42	0%
SERC_Central_KY	102	-	-	3,105	3,207	8%
SERC_Central_TVA	1,198	-	-	-	1,198	3%
SERC_Southeastern	2	-	-	1,313	1,315	3%
SERC_VACAR	2	-	-	7,983	7,985	20%
WECC_BANC	(0)	-	-	390	390	1%
WECC_Colorado	0	501	-	445	946	2%
WECC_Idaho	344	-	-	803	1,147	3%
WECC_Utah	-	-	-	2,212	2,212	6%
Total	**3,407**	**3,538**	**3,895**	**28,589**	**39,429**	**100%**

South Carolina likely would be disproportionately affected by the Proposed Rule's standards associated with CC units, since there are a large number of CC units being added to S_VACAR, and many of those units may be built in South Carolina.

6. IRA impact vs. EPA Proposed Rule

The IRA is expected to enhance opportunities for renewable energy resources and incentivize investment in CCS and hydrogen technologies. The EPA already incorporated the projected impacts of the IRA into the Baseline Case assumptions. Given the optimistic impacts assumed by the EPA, and the results of the EPA's Baseline Case modeling show a significant amount of CO_2 emissions reductions will likely be achieved before any emission reductions are realized under the Proposed Rule. The following Figure 21 demonstrates the expected amount of CO_2 reductions the EPA assumed will be achieved in the Baseline and the Proposed Rule modeling cases.

Figure 21: Comparison of CO_2 Emissions by Case



Again, the EPA expects there will be a dramatic reduction in CO_2 emissions in the Baseline Case, and in fact, there will be little additional reductions in CO_2 emissions as a result of all of the requirements from the Proposed Rule. If the IRA is projected to yield greater reductions in CO_2, the Proposed Rule appears to be unnecessary at this time. This leads to the question of, "Why is the IRA not enough?" However, if the EPA overestimated the amount of CO_2 reductions in the Baseline case, then the EPA likely grossly understated the costs that will occur as a result of the Proposed Rule.

D. Commercial Availability and Reasonableness of the Best System of Emissions Reduction (BSER)

The EPA assumed hydrogen co-firing and CCS technologies will be technically achievable and cost competitive in under ten years should the Proposed Rule go into effect. The assumptions are overly optimistic given the limited use of the hydrogen and CCS technologies today, the need to build a hydrogen-based economy, and challenges to be overcome to construct and utilize CCS technologies.

1. Carbon Capture and Sequestration (CCS)

CCS is far from being commercially available today, as the EPA cited no commercial, utility scale, operating CCS projects existing in the U.S. The only CCS projects in the EPA's list of projects in the U.S. relate to production facilities in the food and agriculture industries, projects used in the oil industry for enhanced oil recovery ("EOR"), projects that were in operation but have already been shut down, or projects that have not yet been constructed that are supported by DOE grants intended to study the feasibility of using CCS in the power generation industry. To date there have been no CCS projects built that have demonstrated the commercial feasibility of CCS at natural gas-fired facilities.[65]

The EPA relied on the engineering firm, Sargent & Lundy, to produce cost estimates, which emphasized the uncertainty of CCS costs given the level of penetration of CCS to date:

> Due to the limited availability of actual as-spent costs for CO_2 capture projects, the cost estimation tool could not be benchmarked against recently executed projects to confirm how accurately it reflects current market conditions.[66]

Aside from the fact the cost assumptions are highly uncertain, the availability of storage locations for CCS are scarce, and essentially do not exist in South Carolina. The RIA documentation provided with the Proposed Rule cites to the National Energy Technology Laboratory ("NETL") National Carbon Sequestration Database and the Geographic Information System ("NATCARB") Atlas for information about potential CCS storage locations.[67] The information indicates a lack of opportunities for CCS in South Carolina, and the IPM modeling does not show CCS as an economic compliance option in South Carolina. CCS was not selected for any of the coal units or gas units in the Proposed Rule case results.

If CCS were a technically feasible option for EGUs in South Carolina, or for other EGUs in other states, there would still be the question of how feasible and expensive it ultimately would be to develop a CO_2 transportation network that would allow CO_2 to be transported to appropriate storage locations. The U.S. Government Accounting Office ("GAO") noted that while there is approximately 5,000 miles of pipeline already built, most of that supports enhanced oil recovery, and there would need to be tens of thousands of additional miles of CO_2 pipeline infrastructure built to support the ability for EGUs to sequester CO_2.[68]

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[65] Government Accounting Office Technology Assessment, "Decarbonization, Status, Challenges, and Policy Options for Carbon Capture, Utilization and Storage, September 2022, p. 10., https://www.gao.gov/assets/gao-22-105274.pdf

[66] IPM Model - Updates to Cost and Performance for APC Technologies CO2 Reduction Retrofit Cost Development Methodology Final March 2023 https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0056/attachment_13.pdf, p. 1.

67 https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas

[68] GAO, Decarbonization Status, September 2022, p. 35, https://www.gao.gov/assets/gao-22-105274.pdf.

If siting natural gas pipeline infrastructure is any indication of the challenges ahead, it will also be difficult to construct CO_2 and hydrogen pipelines across the country. Natural gas pipeline developers currently navigate stringent siting requirements for new natural gas pipelines. In its 2023 IRP, DESC noted the difficulty it expects to encounter in replacing coal capacity with additional natural gas resources, particularly in building new natural gas pipeline capacity:

> Many aspects of the Williams replacement project will be subject to regulatory, procurement and siting processes that are subject to significant schedule risks outside of DESC's direct control. The proposed 2030 retirement date for Williams assumes that those processes are not unduly delayed. At present, the greatest risk appears to be permitting and construction of required natural gas pipeline capacity by the appropriate FERC-regulated interstate pipeline companies, a process that is ultimately outside of DESC's direct control and the control of South Carolina regulators.[69]

2. Hydrogen

The EPA touts hydrogen as a BSER because of its "reasonable cost" and because it believes the feasibility of using hydrogen has been "adequately demonstrated:"

> For the reasons discussed above, cofiring low-GHG hydrogen qualifies as the BSER because it is adequately demonstrated, is of reasonable cost, does not have adverse non-air quality health or environmental impacts or energy requirements—in fact, it offers potential benefits to the energy sector— and reduces GHG emissions. The fact that this control promotes the advancement of hydrogen co-firing in combustion turbines provides additional support for proposing it as part of the BSER. Finally, Congress's direction to choose the ''best'' system of emissions reduction and principles of reasoned decision-making dictate that the standard should be based on burning low-GHG hydrogen, and not using other forms of hydrogen.[70]

A requirement to use low-GHG hydrogen means that hydrogen primarily would have to be produced in an electrolysis process using renewable energy as the source of electricity, and it could take many years before a low-GHG version of hydrogen could become available at a utility scale to be able to meet the EPA's targets. Furthermore, the fact the EPA established a requirement to define how hydrogen has to be produced (using

[69] Dominion Energy's 2023 Integrated Resource Plan, p 32.
[70] Preamble, p. 33316.

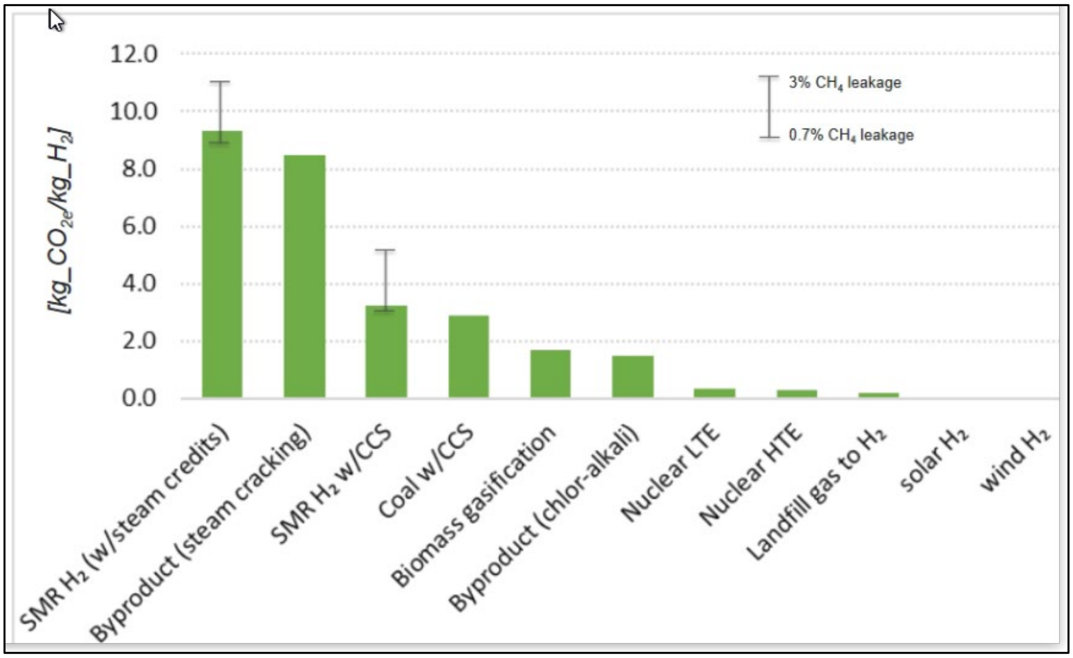
renewable resources), may result in similar legal challenges as the EPA experienced with respect to the Clean Power Plan ("CPP") that was announced in 2015. In other words, the fact that the EPA attempted to define upstream requirements outside of the EGU's property fence lines caused significant problems in the CPP. There may be an argument that the EPA has once again exceeded its authority with the Proposed Rule by creating a power plant standard that requires actions outside the EGU's property fence lines.[71]

Even if the requirement to use low-GHG hydrogen were beyond legal challenge, there are other problems that will have to be overcome to establish hydrogen co-firing as a BSER for natural gas generating units. Low-GHG hydrogen is not produced in significant quantities today and can only be produced by a very limited number of technologies. In a presentation on the Greenhouse Gases, Regulated Emissions, and Energy use in Technologies ("GREET") Model, provided by the Argonne National Lab ("Argonne"), Argonne included a slide that demonstrated how few potential sources there are that could be used to produce low-GHG hydrogen.[72] The EPA's low-GHG hydrogen standard requires hydrogen to produce no more than .45 kg CO2e/kg H2, and the figure below indicates the five technologies listed on the right in the figure are the only ones capable of producing hydrogen per the EPA's requirements. Furthermore, two of the technologies are based on intermittent resources, which are incapable of producing hydrogen on an around-the-clock schedule. The technologies to the far right are electrolysis based and are very expensive, which is why most hydrogen is produced based on the technologies on the left side of the figure, which require fossil fuel to be burned, such as the Steam Methane Reformation ("SMR") process.

[71] In an article published May 3, 2023, in EnergyWire, Scott Segal, a lawyer and co-chair of Bracewell LLP's Policy Resolution Group explained that the EPA would be on "thin legal ice" basing the power plant standard on the origin of hydrogen. https://www.eenews.net/articles/hydrogen-and-the-epa-power-plant-rule-3-issues-to-watch/

[72] GREET Model For Hydrogen Life Cycle GHG Emissions, June 15, 2022, Amgad Elgowainy, PHD, Senior Scientest and Group Leader, Argonne National Laboratory, https://www.energy.gov/sites/default/files/2022-06/hfto-june-h2iqhour-2022-argonne.pdf

Figure 22: GREET Model Presentation[73]
Well-to-gate (WTG) GHG emissions of hydrogen production pathways



There are other significant questions associated with the use of low-GHG hydrogen including the fact it is expensive to produce, costly to transport, and will require major technology breakthroughs to achieve the level of co-firing using hydrogen that the Proposed Rule assumes, 30% by 2032 and 96% by 2038, just six years later.

The Clean Energy Group, which is a non-profit organization that calls for the transition to a clean energy economy, tracks hydrogen projects in the U.S., including new proposed projects, and projects that would involve modifications to existing operating EGUs.[74] None of the projects the Clean Energy Group tracks indicate hydrogen would be used at greater than a 30% mixture. Of the projects listed as increasing beyond a 30% co-firing mixture over time, none of the projects expect the increase to be achieved within six years. For example, a CT project planned by the Intermountain Power Agency ("IPP") in Utah will start on a 30% hydrogen mixture beginning in 2025 and is expected to increase to 100% hydrogen twenty years later "as technology improves."[75] The highest reported test of an existing EGU co-firing using hydrogen in the U.S. occurred at the Hillabee CC Generating Station (753 MW) in May 2023 in Alabama. The owner of the unit, Constellation Energy, reported it was able to achieve a 38% blend rate on hydrogen on the unit that originally

[73] *Id.* slide 8.
[74] The Clean Energy Group's list of Hydrogen Projects in the U.S. is found at https://www.cleanegroup.org/initiatives/hydrogen/projects-in-the-us/#
[75] https://www.ipautah.com/ipp-renewed/

began operating in 2010.[76] This indicates the Proposed Rule's 96% hydrogen co-firing requirement is likely not achievable by 2038.

Hydrogen transportation raises additional significant technical questions, because hydrogen has a low energy density, and a large volume of hydrogen is required to satisfy energy requirements. Liquifying hydrogen is one way hydrogen can be prepared for transport, however, a significant amount of energy must be consumed in the liquefaction process. Another way to transport hydrogen is to pressurize it and transport it via pipelines, however, leakage and safety issues must be addressed. Natural gas pipelines may not be an option to transport hydrogen because hydrogen causes embrittlement problems and requires the use of thicker steel pipelines.[77]

Finally, another significant concern with the Proposed Rule relates to the assumed cost of hydrogen the EPA used in the modeling analyses. At page 33309 of the EPA's Preamble to the Proposed Rule, the EPA expressed confidence that "distribution and storage will not present a barrier to access for new combustion turbines opting to co-fire 30 percent low-GHG hydrogen by volume in 2032 and co-fire 96 percent low-GHG hydrogen by volume in 2038." To achieve the necessary amounts of distribution and storage of hydrogen, the EPA assumed the cost of hydrogen would be $1/kg 2019$ up to 2035, and then after that would drop to $0.5/kg (2019$). Even with the IRA production tax credits ("PTCs") available, there is simply no assurance hydrogen will achieve the low pricing level assumed by the EPA.

If the EPA's forecast of hydrogen costs turns out to be inaccurate, and for example, the cost turns out be 50% higher than that the EPA estimated, then the EPA's estimate of $3.7/MBTU would become a price of $5.55/MBTU, and that could add $238 million over the six year period that hydrogen is forecast to be used in South Carolina alone. Even this would not fully account for all the infrastructure costs that will also be incurred in building out the transportation and storage networks that would be needed to comply with the Proposed Rule.

3. Reliability

In the Proposed Rule, the EPA addressed the fact that reliability is fundamentally important and must be maintained. The following statement within the Proposed Rule indicated the EPA's awareness:

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[76] https://www.constellationenergy.com/newsroom/2023/Constellation-sets-industry-record-for-blending-hydrogen-with-natural-gas-to-further-reduce-emissions.html

[77] https://www.lffgroup.com/posts/hydrogen-an-overview-of-the-issues-associated-with-its-production-storage-and-transportation#

> Furthermore, the EPA is aware that grid operators and power companies currently rely on existing fossil fuel- fired combustion turbines as a flexible and readily dispatchable resource that plays a key role in fulfilling resource adequacy and operational reliability needs. Although advancements in energy storage and accelerated development and deployment of zero-emitting resources may diminish reliance on existing fossil fuel-fired combustion turbines for reliability purposes over time, it is imperative that emission guidelines for these sources not impair the reliability of the bulk power system. For these reasons, the EPA believes that it is important that a BSER determination and associated emission guidelines for existing fossil fuel-fired combustion turbines rely on GHG control options that can be feasibly and cost-effectively implemented at a scale commensurate with the size of the regulated fleet, and provide sufficient operational flexibility and lead time to allow for smooth implementation of the GHG emission limitations that preserves system reliability." (p. 33361)

However, there is no guarantee reliability will be maintained if the Proposed Rule is implemented. In 2014, ahead of the introduction of the prior CPP CO_2 rule, NERC's Board of Trustees directed NERC staff to "develop a series of special reliability assessments to examine the potential risks to reliability that may arise from the implementation of the CPP rule…."[78] In the review NERC conducted, it presented the following Key Finding "2. Industry needs more time to develop coordinated plans to address shifts in generation and corresponding transmission reinforcements to address proposed CPP CO2 interim and other emission targets." and "4. Energy and capacity will shift to gas-fired generation, requiring additional infrastructure and pipeline capacity."[79]

Although the EPA emphasized the fundamental importance of considering reliability, it appears that the EPA did not request or prevail upon NERC to conduct a similar reliability assessment with regard to the Proposed Rule. Reliability is critical and Kennedy recommends that before the EPA pursues any further action on the Proposed Rule, the NERC should conduct a similar reliability assessment as was conducted in 2014.

4. Other Considerations

In addition to the concerns identified above regarding the use of CCS and hydrogen technologies, Kennedy has the following additional concerns given the technologies are not yet commercially available.

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78 Potential Reliability Impacts of EPA's Proposed Clean Power Plan Phase I April 2015, at p. v.
79 *Id.* at vii and ix.

1) **Use of hydrogen over a six-year period -** According to the EPA's modeling analyses, EGUs in South Carolina, and in other parts of the U.S., will only rely on the use of hydrogen co-firing for a six-year period, based on the model run year 2035. Kennedy is concerned that it would be unrealistic to assume that new hydrogen production and transportation infrastructure would materialize in the U.S. if EGUs in states such as South Carolina only rely on hydrogen for a six-year period.

2) **Supply chain issues** - In recent times, supply chain issues that started when COVID struck, caused major disruptions to the solar power, semi-conductor manufacturing, automobile, and other industries. Other factors have continued to exacerbate supply chain issues, including trade practice issues, shifts in demand, labor shortages, structural factors, and geopolitical events, even after the initial shocks of COVID have waned. With the significant increase in demand for the use of hydrogen and CCS, supply chain issues could continue to be a major problem, especially if capital investment and supply is unable to keep pace with the demand for hydrogen and CCS technologies.

3) **Mega-scale projects -** To meet the requirements of the EPA's Proposed Rule, hydrogen and CCS technologies will require huge investments over a short period of time. In recent years, there have been examples of large construction projects that were cancelled or significantly delayed due to technical or construction issues. One example is Mississippi Power's Plant Kemper Integrated Gasification Combined Cycle ("IGCC") Project that was approved for construction in 2009 and cancelled in 2018. The project was partially funded using grants from the DOE that helped fund research into cleaner generation using coal.[80] The EPA has not accounted for the possibility that similar problems could arise in attempting to ramp up complex new hydrogen and CCS industries in the U.S. that do not exist today.

4) **Transmission and Pipeline Construction** - To meet the requirements of the EPA's Proposed Rule, the electric utility industry will need to make large and simultaneous investments in transmission and natural gas pipelines. The U.S. DOE Office of Policy states, "Independent estimates indicate that to meet our growing clean electricity demands, we'll need to expand transmission systems by 60% by 2030 and may need to triple those systems by 2050. That means significant investments in transmission infrastructure will be required to meet our climate goals and unlock the benefits that the clean energy transition presents from spurring economic growth, to revitalizing domestic manufacturing, to creating millions of good jobs for American workers."[81]

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[80] https://mspolicy.org/two-years-since-kemper-clean-coal-project-ended/
[81] https://www.energy.gov/policy/queued-need-transmission

E. South Carolina Impacts

1. Costs to South Carolina

Kennedy identified numerous issues with the EPA's assumptions and IPM modeling approach that led to the conclusion that the EPA's results are counterintuitive and understated. Kennedy used the EPA's IPM model outputs to identify the EPA's South Carolina state level results. An issue arose, however, in that Kennedy could not reconcile all of the results that appeared in the EPA's IPM model outputs to what appeared in the RIA Report. The tables that follow rely on results that appeared in the IPM model output.

Figure 23: EPA Modeled Compliance Costs Assigned to South Carolina (Negative Implies a Savings)

Estimated Compliance Costs ($2019 millions)	2028	2030	2035	2040	2028-2042
FOM (Avoided)	17	(66)	(90)	(14)	(789)
VOM (Avoided)	(20)	5	(7)	(20)	(148)
Fuel Costs (Avoided)	(62)	178	(12)	(133)	(263)
Capital Costs	46	(8)	16	152	873
Total Compliance Costs	**(18)**	**108**	**(94)**	**(15)**	**(328)**

Figure 23 shows the difference in production costs between the Baseline Case and the Proposed Rule Case for the four model years run in the EPA's IPM model. Kennedy expanded the results to cover all of the study period years (2028 to 2042), and those results appear in the far right column. Over the entire study period, the EPA's modeling analysis shows an additional $873 million will be spent on capital costs by implementing the Proposed Rule. Likewise, the EPA's modeling analysis shows South Carolina would be expected to save $1,200 in FOM, VOM, and Fuel Costs over the entire study period. The net impact of the modeling is that the EPA assumes that South Carolina would be expected to save $328 million over the study period by implementing the Proposed Rule.

The fact that the EPA's modeling results indicate that South Carolina would save $328 million over the study period after implementing the Proposed Rule is unrealistic and counter intuitive. One explanation for the unrealistic savings in the Proposed Rule case is that the EPA assumed the natural gas and coal forecasts would be lower in the Proposed Rule case, which is an unrealistic expectation. As mentioned above, even if it were necessary to rely on equilibrium pricing modeling logic for natural gas and coal price forecasts, then the EPA should have also relied on equilibrium pricing modeling logic for renewable resource capital and O&M price forecasts, and hydrogen forecasts, which would have raised the cost of the Proposed Rule case considerably. Another reason the EPA's modeling results are unrealistic relates to the fact that the EPA did not account for infrastructure costs that would be necessary to build out pipeline and transmission capacity that would be required to comply with the Proposed Rule. The additional, unaccounted for costs could end up costing billions of dollars more than the EPA has included in the modeling analyses it performed.

Furthermore, if the options that were available in the Proposed Rule case were truly economic, then those options should have been implemented in the Baseline Case. It is simply illogical that the EPA's modeling shows that in South Carolina coal units would be forced to retire early, natural gas CC units would be forced to operate at reduced capacity factor levels, gas units would be converted to hydrogen, and thousands of MWs of additional battery storage, On-shore Wind, and Solar PV resources would be added to the South Carolina grid, and yet the production costs would be lower with those changes.

Figure 24 shows a comparison of expansion plans the EPA derived for the Updated Baseline and Integrated Proposal cases at the end of the study period in 2042. The capacity values shown are expressed in nameplate capacity megawatts. While changes to the expansion plan will occur in the years between 2028 and 2042, Figure 24 just shows the EPA's derived expansion plans as they are expected to exist in the year 2042. All of the rows above the row labeled "Existing Nucl, Hyd, Renew, Gas" refer to either existing or new South Carolina resources that are assumed to be affected by the EPA's Proposed Rule.

Figure 24: South Carolina Expansion Plan (Nameplate MW)

End of Study (2042)		**Updated Baseline**	**Integrated Proposed Rule**	**Delta**
Existing	Coal	2,350	0	(2,350)
Existing CC	BAU Operation	3,185	2,401	(784)
	CF limited	0	784	784
New CC	Natural Gas Fired	3,113	0	(3,113)
	Hydrogen Retrofit	0	0	0
	Return to Natural Gas	0	3,399	3,399
New	CT (Natural Gas)	2,149	2,561	412
	Landfill Gas	45	45	0
	Battery	1,947	2,298	351
	On-shore Wind	6,275	8,042	1,767
	New Solar PV	16,794	18,481	1,687
Existing	Nuc, Hyd, Renew, Gas	15,914	15,914	0
Total		**51,771**	**53,925**	**2,154**

The Integrated Proposed Rule Case shows that all coal units will be retired by the end of the study period, and some of the existing CC units (784 MW) will transition to capacity factor limited operation.

Since Figure 24 just presents a snapshot in 2042, it does not tell the whole story regarding the EPA's assumed changes to the New Natural Gas-Fired CC units. Appendix C presents another view of the results, in which all years are shown for the Updated Baseline Case, the Proposed Rule Case, and the difference between the two cases (Delta). The results for the Proposed Rule Case indicate that 3,033 MWs of New Natural Gas-Fired CC units will be added in 2028, then those resources will be converted to hydrogen operation beginning in 2032, and those units will switch back again to natural gas operation in 2038. The EPA's rule allows CC units to switch back to natural gas operation when capacity factors fall below 50%. As discussed previously, it is unimaginable that the utility industry would be overhauled to rely on hydrogen for just a six-year period.

Figure 24 indicates that as much as 8,042 MW of On-shore wind capacity will be added by 2042 in the Proposed Rule case. In fact, Appendix C shows that the EPA expects that 2,990 MW of On-shore Wind would be added in the Updated Baseline Case as early as 2028, just five years from now. These results are unrealistic.

It is also arguable whether 17,000 MWs of solar capacity could be integrated into the South Carolina grid in the Proposed Rule case over the study period. Even more questionable is that the EPA assumes that between 2037 and 2038, 16,000 MW of solar resources would be added to the South Carolina grid in that year alone. Furthermore, the availability of land to site 17,000 MW of solar resources in South Carolina is an issue as well. If a MW of solar capacity were assumed to require six acres of land, building 17,000 MW of solar in South Carolina would require about 160 square miles. While it is not out of the question that that much solar capacity could be added to the South Carolina grid over the study period, there are still enormous challenges that would have to be overcome to be able achieve the EPA's outcome, including issues with capital investment, land requirements, interconnection queue problems, transmission upgrades, permitting and regulatory approval, etc.

2. Additional Areas of Flexibility Required

The most significant concerns identified in this Report relate to reliability and the feasibility of implementing the transition of the EGU fleet as the EPA has contemplated on the timeline indicated in the Proposed Rule. If the EPA continues to move forward with the Proposed Rule, it should consider ways to offer EGU's additional flexibility in complying with the requirements of the rule. For example, the EPA should include a "safety valve" provision to ensure reliability is prioritized above emissions reductions. This might involve means by which the rules could be violated if reliability issues were anticipated to arise.

Before moving forward with the Proposed Rule, the EPA should conduct additional detailed modeling and compliance plan analysis to address the many modeling problems that have been identified in this report. Appendix A below contains specific comments regarding the need for flexibility in response to the requests for comments issued by EPA in the preamble, as published in the federal registrar and the RIA analysis. Appendix B provides information on the data quality issues that the EPA should address by performing additional detailed modeling and compliance plan analysis.

Appendix A – EPA Requested Comments

Appendix A is provided to reflect upon the specific questions posed by EPA within the preamble and RIA analysis. This document includes the quoted text and source of the EPA requested comments and a brief responsive comment that summarizes the concerns described in this report.

- "If the steam generating unit were not permitted to operate when CCS was unavailable, there may be local reliability consequences, and the EPA is soliciting comment on how to balance these issues." (p 33356)

  Comment: A "safety valve" mechanism should be built into the final version of the rule. To the extent that specific components are temporarily unavailable or market transformation is not as quick as anticipated, the States need sufficient authority to ensure resource adequacy and reliability.

- "As discussed in section XII.E, the EPA is proposing to allow trading and averaging under the proposed emission guidelines and requesting comment on whether and how such compliance mechanisms could be implemented to ensure equivalency with the emission reductions that would be achieved if each affected source was achieving its applicable standard of performance." (p 33340)

  "This section discusses considerations related to such compliance flexibilities in the context of this particular rule and set of regulated sources—existing steam generating units and existing combustion turbine EGUs—and solicits comment on whether certain types of averaging and trading maintain the stringency of the EPA's BSER." (p 33392)

  "The EPA requests comment on whether state plans should be allowed to provide for banking of tradable compliance instruments (hereafter referred to as "allowance banking," although it is relevant for both mass-based and rate-based trading programs)." (p 33396)

  Comment: A single compliance target, such as a rate based or mass based target, may ultimately allow for more flexibility in compliance, especially if there is a mechanism in place to allow some facilities to comply to a more rigorous standard (CCS) while allowing for a less rigorous standard of hydrogen co-firing or capacity factor limitation at another facility. Allowing for trading and averaging would provide additional flexibility that a state might require in developing a compliance plan. Allowing for flexibility in compliance period may benefit states in planning if a unit can comply earlier to help smooth out a future abrupt compliance requirement shift.

- “The EPA specifically solicits comment on whether rural areas and small utility distribution systems (serving 50,000 customers or less) can expect to have access to low-GHG hydrogen. To the extent low-GHG hydrogen might be less available in rural areas compared to areas with higher population densities, the EPA solicits comment if sufficient electric transmission capacity is available, or could be constructed, such that electricity generated from low-GHG hydrogen could be transmitted to these rural areas.” (p 33313)

  “The EPA is also soliciting comment on whether hydrogen infrastructure is likely to be sufficiently developed by 2030 to provide access to low-GHG hydrogen for new and reconstructed combustion turbines.” (p 33309)

  “More specifically, the EPA is requesting comment on how to consider the rate of CCS (and potentially hydrogen) infrastructure development in determining a BSER that could potentially impact hundreds of sources.” (p 33370)

  <u>Comment</u>: Transmission and access to hydrogen supply and transportation pipeline infrastructure is a risk for all utility systems in South Carolina. Creating standards that would require widespread compliance requirements in a short period of time could be enormously expensive and possibly impossible to achieve.

- “The EPA is soliciting comment on the capacity and capacity factor threshold for inclusion in the subcategory of large, frequently operated turbines (e.g., capacities between 100 MW and 300 MW for the capacity threshold and a lower capacity factor threshold (e.g., 40 percent).” (p 33246)

  <u>Comment</u>: EPA should define summer, winter, or nameplate as the threshold when considering a finalized rule.

- “EPA is soliciting comment on power sector modeling of the IRA, including the assumptions and potential impacts, including assumptions about growth in electric demand, rates at which renewable generation can be built, and cost and performance assumptions about all relevant technologies, including carbon capture, renewables, energy storage and other generation technologies.” (p 33264)

  <u>Comment</u>: The EPA’s modeling results already demonstrate significant reductions in CO_2 because of the IRA. See report above for assessment of assumptions.

- “For details on the hydrogen modeling assumptions used in this analysis, please see Section 3 of this RIA.8 Under the proposal and less stringent scenarios, the second phase of the NSPS is assumed to be active in 2035, while under the more stringent scenario, the second phase of the NSPS is assumed to be active in 2030. The lower input hydrogen fuel price in 2030 under the more stringent scenario therefore drives total compliance costs lower than under the other two scenarios. EPA solicits comments in section XIV(B) of the preamble on its cost estimation generally." (RIA, p. ES-12)

Comment: Hydrogen pricing assumed in the modeling are very likely overly optimistic and therefore compliance costs modeled may be understated.

- "The EPA is taking comment on whether HRI should be considered BSER (or a component of BSER) for combined cycle units with a capacity factor of greater than 50 percent and a capacity of less than 300 MW as part of this initial rulemaking." (p 33363)

  Comment: It was unclear if Heat Rate Improvement (HRI) was a modeled compliance pathway for existing EGU compliance in IPM. For combined cycle units with a capacity of less than 300 MW, no specific compliance was contemplated. The EPA should not introduce new compliance requirements without sufficient modeling and comment period.

- "The EPA also requests comment from potentially impacted communities and other pertinent stakeholders on any considerations related to providing a longer state plan submission timeframe under these emission guidelines." (p 33403)

  "The EPA is therefore requesting comment on an approach in which states would submit two different plans on different timelines: a state plan addressing affected steam-generating units due 24 months after promulgation of these emission guidelines and a second state plan addressing affected combustion turbine EGUs due 36 months after promulgation of these emission guidelines" (p 33403)

  Comment: States need as long as possible to consider potential compliance strategies and coordinate with local utilities and stakeholders.

Appendix B - Data Quality and Production Requests to EPA

Appendix B is provided to summarize the areas of data discrepancy identified in our brief review of the analysis provided by EPA. This document includes questions regarding specific files and data discrepancies identified. The provided IPM data lacks transparency and the translation of output to results was not well defined.

1. Refer to "Raw – IPM Costs" tab in EPA-HQ-OAR-2023-0072-0008_content.xlsx, there is a note in cell B1 describing the SSR files as the data source, but it is unclear where in the SSR files these values could be found. Please explain which SSR files and cells these numbers in C7:F8 can be traced back to.

2. The IPM model documentation describes the aggregation algorithm used to take the NEEDs database to IPM inputs. Please indicate which provided file contains the mapping between NEEDS and IPM if it was provided. If it was not provided, please provide the file that shows the NEEDS to IPM aggregation and unit ID information.

3. Is the 300 MW threshold for compliance in the proposal for existing generating unit compliance based on a nameplate, summer, or winter capacity rating?

4. The input (.DAT) for the integrated proposal doesn't appear to include O&M costs for unit ID 2590 (Wateree) and subsequent CCS child/grandchild iterations (Unit 46308). Please explain and reconcile to the VOM assumptions described for Coal for CCS in table 6-2 of the IPM documentation.

5. The input (.DAT) for the integrated proposal does not appear to include O&M costs for unit ID 57201 (CEC) and subsequent CCS child/grandchild iterations (Unit 56589 and 57201). Please explain and reconcile to the VOM assumptions described for CCS in table 6-2 of the IPM documentation.

6. Can the EPA provide a version of the .DAT resources that provide more information around the compliance options and resource decision dependency and decision tree? It appears that unit IDs 13691 and 36306 are pre-requisite operational units with costs and heat rate penalties for online year 2023 before retirement in 2023. It is unclear how these units are utilized in the expansion plan analysis.

7. Please explain if Heat Rate improvement modeling compliance options were included in the IPM modeling or contemplated as a compliance methodology for the proposal.

8. See EPA initial RIA results in table 3-7, why do the results show that the "more stringent" case costs less than the "proposal" case in 2030?

9. Please provide the file contains the nomenclature coding for the IPM model capacity reporting type output. For example, the NEEDS database "NEEDS rev 02-14-2023 (xlsx)" includes a "Key to Emissions Control" tab, and the " Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model" contains various explanations, but its unclear how capacity reporting types labeled "dummy" and "DRET" are defined.

10. Table 11 of the "INTEGRATED PROPOSAL MODELING AND UPDATED BASELINE ANALYSIS" shows 238 TWh of hydrogen in 2035 for the Integrated Proposal case, whereas the "Integrated Proposal SSR.xlsx" file shows 79 TWh and 42 TWh in cells D1773:E1773 of the "Table 1-16_US" tab. Please reconcile.

Appendix C – EPA Expansion Plans (South Carolina)

Appendix C shows the expansion plan results the EPA's IPM modeling analyses derived. As described above, there were flaws in the analyses that were conducted, and therefore these results are unreasonable.

UPDATED BASELINE (MW)		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Existing	Coal	3,480	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350
Existing	CC - BAU Operation	3,185	3,185	3,185	3,185	3,185	3,185	3,185	3,185	3,185	3,185	3,185	3,185	3,185	3,185	3,185
	CC - CF limited															
New	CC - Natural Gas Fired	2,140	2,140	2,140	2,140	3,113	3,113	3,113	3,113	3,113	3,113	3,113	3,113	3,113	3,113	3,113
	CC - Hydrogen Retrofit															
	CC - Return to Natural Gas															
New	CT (Natural Gas)											2,149	2,149	2,149	2,149	2,149
	Landfill Gas	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
	Battery	994	1,653	1,653	1,653	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947
	On-shore Wind	-	2,990	2,990	2,990	5,999	5,999	5,999	5,999	5,999	5,999	6,275	6,275	6,275	6,275	6,275
	New Solar PV	1,784	1,784	1,784	1,784	5,722	5,722	5,722	5,722	5,722	5,722	16,794	16,794	16,794	16,794	16,794
Existing	Nuc, Hyd, Renew, Gas	16,059	16,192	16,192	16,192	15,607	15,607	15,607	15,607	15,607	15,607	15,914	15,914	15,914	15,914	15,914
Total		**27,687**	**30,339**	**30,339**	**30,339**	**37,967**	**37,967**	**37,967**	**37,967**	**37,967**	**37,967**	**51,771**	**51,771**	**51,771**	**51,771**	**51,771**

Integrated Proposal (MW)		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Existing	Coal	3,480	2,350	2,350	2,350											
Existing	CC - BAU Operation	3,185	3,185	3,185	3,185	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401
	CC - CF limited	-	-	-	-	784	784	784	784	784	784	784	784	784	784	784
New	CC - Natural Gas Fired	3,033	3,033	3,033	3,033											
	CC - Hydrogen Retrofit					3,399	3,399	3,399	3,399	3,399	3,399					
	CC - Return to Natural Gas											3,399	3,399	3,399	3,399	3,399
New	CT (Natural Gas)	-	-	-	-	895	895	895	895	895	895	2,561	2,561	2,561	2,561	2,561
	Landfill Gas	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
	Battery	589	1,847	1,847	1,847	2,298	2,298	2,298	2,298	2,298	2,298	2,298	2,298	2,298	2,298	2,298
	On-shore Wind	-	587	587	587	5,999	5,999	5,999	5,999	5,999	5,999	8,042	8,042	8,042	8,042	8,042
	New Solar PV	1,784	1,784	1,784	1,784	2,430	2,430	2,430	2,430	2,430	2,430	18,481	18,481	18,481	18,481	18,481
Existing	Nuc, Hyd, Renew, Gas	16,059	16,192	16,192	16,192	15,607	15,607	15,607	15,607	15,607	15,607	15,914	15,914	15,914	15,914	15,914
Total		**28,174**	**29,022**	**29,022**	**29,022**	**33,857**	**33,857**	**33,857**	**33,857**	**33,857**	**33,857**	**53,925**	**53,925**	**53,925**	**53,925**	**53,925**

Delta (MW)		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Existing	Coal	-	-	-	-	(2,350)	(2,350)	(2,350)	(2,350)	(2,350)	(2,350)	(2,350)	(2,350)	(2,350)	(2,350)	(2,350)
Existing	CC - BAU Operation	-	-	-	-	(784)	(784)	(784)	(784)	(784)	(784)	(784)	(784)	(784)	(784)	(784)
	CC - CF limited	-	-	-	-	784	784	784	784	784	784	784	784	784	784	784
New	CC - Natural Gas Fired	893	893	893	893	(3,113)	(3,113)	(3,113)	(3,113)	(3,113)	(3,113)	(3,113)	(3,113)	(3,113)	(3,113)	(3,113)
	CC - Hydrogen Retrofit	-	-	-	-	3,399	3,399	3,399	3,399	3,399	3,399	-	-	-	-	-
	CC - Return to Natural Gas	-	-	-	-	-	-	-	-	-	-	3,399	3,399	3,399	3,399	3,399
New	CT (Natural Gas)	-	-	-	-	895	895	895	895	895	895	412	412	412	412	412
	Landfill Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Battery	(405)	194	194	194	351	351	351	351	351	351	351	351	351	351	351
	On-shore Wind	-	(2,403)	(2,403)	(2,403)	-	-	-	-	-	-	1,767	1,767	1,767	1,767	1,767
	New Solar PV	-	-	-	-	(3,292)	(3,292)	(3,292)	(3,292)	(3,292)	(3,292)	1,687	1,687	1,687	1,687	1,687
Existing	Nuc, Hyd, Renew, Gas	49	-	-	-	49	49	49	49	49	49	-	-	-	-	-
Total		**536**	**(1,316)**	**(1,316)**	**(1,316)**	**(4,061)**	**(4,061)**	**(4,061)**	**(4,061)**	**(4,061)**	**(4,061)**	**2,154**	**2,154**	**2,154**	**2,154**	**2,154**