Initial Regulatory Flexibility Analysis

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

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The Regulatory Flexibility Act (RFA; 5 U.S.C.§ 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104-121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis (IRFA), unless it certifies that the proposed rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. § 605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions. An IRFA describes the economic impact of the proposed rule on small entities and any significant alternatives to the proposed rule that would accomplish the objectives of the rule while minimizing significant economic impacts on small entities.

On May 23, 2023, the Environmental Protection Agency (EPA) proposed revised new source performance standards (NSPS) for greenhouse gas (GHG) emissions from new fossil fuel-fired stationary combustion turbine electric generating units (EGUs) and from fossil fuel-fired steam generating units that undertake a large modification.[1] Based on the information available to EPA at the time the proposal, EPA certified the proposed rule as not having a significant economic impact on a substantial number of small entities.[2] However, EPA solicited comment on a number of policy options as described in detail in Section 2 of this document that, if finalized, may affect the estimate of total compliance costs and therefore the impacts on small entities. As outlined in section 3, EPA also revised its small business screening criteria based on feedback from the panel which also affects the estimated impacts on small businesses.

Therefore, the EPA prepared an IRFA that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The scope of the IRFA is limited to the proposed new source performance standards. The impacts of the proposed emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines and existing fossil fuel-fired steam generating units are not evaluated here because the emission guidelines do not place explicit requirements on the regulated industry. Those impacts will be evaluated pursuant to the development of a Federal plan.

1. Reasons Why Action is Being Considered

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare. Since that time, the evidence of the harms posed by GHG emissions has only grown and Americans experience the destructive and worsening effects of climate change every day. Fossil fuel-fired EGUs are the nation's largest stationary source of GHG emissions, representing 25 percent of the United States' total GHG emissions in 2020. At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources are available to the power sector, and multiple projects are in various stages of operation and development—including carbon capture and sequestration/storage (CCS) and co-firing with lower-GHG fuels. Congress has also acted to provide funding and other incentives to encourage the deployment of these technologies to achieve reductions in GHG emissions from the power sector.

[1] See 88 FR 33240 (May 23, 2023).
[2] See 88 FR 33418 (May 23, 2023).

In May 2023, the EPA proposed several actions under section 111 of the Clean Air Act (CAA) to reduce the significant quantity of GHG emissions from fossil fuel-fired EGUs by establishing NSPS and emission guidelines that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of section 111, the proposed NSPS and emission guidelines reflect the application of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated.

Each of the NSPS and emission guidelines proposed would ensure that EGUs reduce their GHG emissions in a manner that is cost-effective and improves the emissions performance of the sources, consistent with the applicable CAA requirements and caselaw. These proposed standards and emission guidelines, if finalized, would significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. Further, the EPA designed these proposed standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.

2. Statement of Objectives, Legal Basis, and Summary of the Proposed Rule

The EPA's authority for and obligation to issue this proposed rule is CAA section 111, which establishes mechanisms for controlling emissions of air pollutants from new and existing stationary sources. CAA section 111(b)(1)(A) requires the EPA Administrator to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, and distinguish among classes, types, and sizes within categories in establishing the standards.

For new and reconstructed fossil fuel-fired combustion turbines, the EPA proposed creating three subcategories based on the function the combustion turbine serves: a low load ("peaking units") subcategory that consists of combustion turbines with a capacity factor of less than 20 percent; an intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the combustion turbine; and a base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines. This subcategorization approach is similar to the 2015 NSPS for these sources, which includes separate subcategories for base load and non-base load units; however, the EPA proposed to subdivide the non-base load subcategory into a low load subcategory and a separate intermediate load subcategory. This revised approach to subcategories is consistent with the fact that utilities and power plant operators are building new combustion turbines with plans to operate them at varying levels of capacity, in coordination with existing and expected energy sources. These patterns of operation are important for the type of controls that the EPA proposed as the BSER for these turbines, in terms of the feasibility of, emissions reductions that would be achieved by, and cost-reasonableness of, those controls.

For the low load subcategory, the EPA proposed that the BSER is the use of lower emitting fuels (e.g., natural gas and distillate oil) with standards of performance ranging from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on the type of fuel combusted. For the intermediate load and base load subcategories, the EPA proposed an approach in which the BSER has multiple components: (1) Highly efficient generation; and (2) depending on the subcategory, use of CCS or co-firing low-GHG hydrogen.

These components of the BSER for the intermediate and base load subcategories form the basis of a standard of performance that applies in multiple phases. That is, affected facilities must meet the first phase of the standard of performance, which is based exclusively on application of the first component of the BSER (highly efficient generation), by the date the rule is promulgated. Affected sources in the intermediate load and base load subcategories must also meet the second and in some cases third and more stringent phases of the standard of performance, which are based on the continued application of the first component of the BSER and the application of the second and in some cases third component of the BSER. For base load units, the EPA proposed two pathways as potential BSER:

- the use of CCS to achieve a 90 percent capture of GHG emissions by 2035 and
- the co-firing of 30 percent (by volume) low-GHG hydrogen by 2032, and ramping up to 96 percent by volume low-GHG hydrogen by 2038.

These two BSER pathways both offer significant opportunities to reduce GHG emissions but may be available on slightly different timescales. Depending upon the phase-in periods for both CCS and hydrogen, the CCS pathway could provide greater cumulative emission reductions than the low-GHG hydrogen pathway.

More specifically, with respect to the first phase of the standards of performance, the EPA proposed that the BSER for both the intermediate load and base load subcategories includes highly efficient generating technology (i.e., the most efficient available combustion turbines). For the intermediate load subcategory, the EPA proposed that the BSER includes highly efficient simple cycle turbine technology with an associated first phase standard of 1,150 lb CO_2/MWh-gross. For the base load subcategory, the EPA is proposing that the BSER includes highly efficient combined cycle technology with an associated first phase standard of 770 lb CO_2/MWh-gross for larger combustion turbine EGUs with a base load rating of 2,000 MMBtu/h or more. For smaller base load combustion turbines (with a base load rating of less than 2,000 MMBtu/h), the proposed associated standard ranges from 770 to 900 lb CO_2/MWh-gross depending on the specific base load rating of the combustion turbine. These standards would apply immediately upon the effective date of the final rule.

With respect to the second phase of the standards of performance, for the intermediate load subcategory, the EPA proposed that the BSER includes co-firing 30 percent by volume low-GHG hydrogen (unless otherwise noted, all co-firing hydrogen percentages are on a volume basis) with an associated standard of 1,000 lb CO_2/MWh-gross, compliance with which would be required starting in 2032. For the base load subcategory, to elicit comment on both pathways, the EPA proposed to subcategorize further into base load units that are adopting the CCS pathway and base load units that are adopting the low-GHG hydrogen co-firing pathway. For the subcategory of base load units that are adopting the CCS pathway, the EPA proposed that the BSER includes the use of CCS with 90 percent capture of CO2 with an associated standard of 90 lb CO_2/MWh-gross, compliance with which would be required starting in 2035. For the subcategory of base load units that are adopting the low-GHG hydrogen co-firing pathway, the EPA proposed that the BSER includes co-firing 30 percent (by volume) low-GHG hydrogen with an associated standard of 680 lb CO_2/MWh-gross, compliance with which would be required starting in 2032, and co-firing 96 percent (by volume) low-GHG hydrogen by 2038, which corresponds to a standard of performance of 90 lb CO_2/MWh-gross. In both cases, the second (and sometimes third) phase standard of performance would be applicable to all combustion turbines that were subject to the first phase standards of performance.

EPA estimated the impacts of the proposed rule using the Integrated Planning Model (IPM) as part of the Regulatory Impact Analysis (RIA). This analysis estimated total national compliance costs stemming from the proposed regulations (as outlined above). The compliance costs associated with the new source standards were then apportioned to small entities that had built new combustion turbines since 2017. These compliance costs were then compared to the sales for each entity to determine whether or not a Significant Economic Impact on a Substantial Number of Small Entities (SISNOSE) was projected (for details of the analysis please see Section 3 below). As proposed, EPA estimated a finding of no SISNOSE. However, EPA took comment on a number of policy options including:

- Reducing the electric sales threshold for low load combustion turbines,
- A BSER of high efficiency simple cycle turbines for low load combustion turbines that would include an initial performance test,
- A second component of the BSER of co-firing hydrogen for low load combustion turbines,
- A lower first component BSER emissions standard for intermediate load combustion turbines,
- A second component and third component of the BSER for intermediate load combustion turbines based on a higher percentage of hydrogen co-firing,
- Separate BSER determinations for simple cycle and combined cycle intermediate load combustion turbines,
- Earlier timing of the second component of the BSER for intermediate load combustion turbines, and,
- A lower electric sales threshold for base load combustion turbines.

In general, the imposition of different policy design elements, including those in the list above, could result in higher or lower compliance costs for new combustion turbines. If the final rule includes policy design elements that increase the estimated costs to the identified small entities, this could result in higher cost-to-sales ratio impacts for the identified small entities, and therefore result in the finding that EPA is unable to declare no SISNOSE. Hence EPA conducted this IRFA in order to gather feedback from small businesses to inform final rule development.

3. Description and Estimate of Affected Small Entities

For the proposed rules, EPA performed a small entity screening analysis for impacts on all affected EGUs by comparing compliance costs to historic revenues at the ultimate parent company level. This is known as the cost-to-revenue or cost-to-sales test, or the "sales test." The sales test is an impact methodology EPA employs in analyzing entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is frequently used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Also, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by EPA on compliance with the Regulatory Flexibility Act (RFA)[3] and is consistent with guidance published by the U.S. Small Business Administration's (SBA) Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities.[4]

This section presents the methodology and results for estimating the impact of the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units on small EGU entities in 2035 based on the following endpoints:

- annual economic impacts of the proposal on small entities, and
- ratio of small entity impacts to revenues from electricity generation.

This rule would affect the buildout and operation of future natural gas combined cycle (NGCC) and natural gas combustion turbine (NGCT) additions. Costs are projected to peak in 2035, which is consistent with the imposition of the second phase of the NSPS requirements on new NGCC builds, and as such, the analysis focuses on this year. While IPM can provide important information about the future operation and addition of natural gas capacity over the analysis period, the model does not project actions taken by individual firms. Hence, as a proxy for the future gas capacity built by small entities EPA assumed that the same small entities identified using the process outlined below would continue to build the same share of future capacity additions projected by IPM over the forecast period.

EPA reviewed historical data and planned builds since 2017 to determine the universe of NGCC and NGCT additions as outlined in EPA National Electric Energy Data System (NEEDS) v.6 database. The NEEDS database includes operational capacity in the year of publication as well as capturing planned/committed units that are likely to come online because ground has been broken, financing obtained, or other demonstrable factors indicate a high probability that the unit will be built before June 30, 2028.[5] EPA included these planned/committed units when calculating the share of builds that are owned by small entities. Additionally, based on feedback

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[3] The RFA compliance guidance to EPA rule writers can be found at: https://www.epa.gov/sites/default/files/2015-06/documents/guidance-regflexact.pdf.

[4] See U.S. SBA Office of Advocacy. (2017). A Guide For Government Agencies: How To Comply With The Regulatory Flexibility Act. Available at: https://advocacy.sba.gov/2017/08/31/a-guide-for-government-agencies-how-to-comply-with-the-regulatory-flexibility-act/.

[5] For details please see Chapter 4.3 IPM base case documentation, available at: https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf.

received from the Panel, EPA updated the analysis to include information from the latest SBA guidelines[6] and corrected data errors in the earlier screening methodology, the net impact of which results in inclusion of additional small entities within the updated screening analysis.

Based on these criteria, EPA identified a total of 53 GW of NGCC and 7 GW of NGCT built since 2017. Next, we determined power plant ownership information, including the name of associated owning entities, ownership shares, and each entity's type of ownership. Ownership information for these assets was obtained primarily using data from Ventyx[7], supplemented by research using S&P[8] and publicly available data.

Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.[9] These ownership types are:

1. Investor-Owned Utility (IOU): Investor-owned assets (e.g., a marketer, independent power producer, financial entity) and electric companies owned by stockholders, etc.
2. Cooperative (Co-Op): Non-profit, customer-owned electric companies that generate and/or distribute electric power.
3. Municipal: A municipal utility, responsible for power supply and distribution in a small region, such as a city.
4. Sub-division: Political subdivision utility is a county, municipality, school district, hospital district, or any other political subdivision that is not classified as a municipality under state law.
5. Private: Similar to an investor-owned utility, however, ownership shares are not openly traded on the stock markets.
6. State: Utility owned by the state.
7. Federal: Utility owned by the federal government.

Next, EPA used the D&B Hoover's online database, the Ventyx database, and the S&P database to identify the ultimate owners of power plant owners identified in the NEEDS database. This was necessary, as many majority owners of power plants (listed in Ventyx) are themselves owned by other ultimate parent entities (listed in D&B Hoover's)[10]. In these cases, the ultimate parent entity was identified via D&B Hoover's, whether domestically or internationally owned.

EPA followed SBA size standards to determine which non-government ultimate parent entities should be considered small entities in this analysis. These SBA size standards are specific to each industry, each having a threshold level of either employees, revenue, or assets below which an entity is considered small.[11] SBA guidelines list all industries, along with their

[6] For details, please see: https://www.sba.gov/document/support-table-size-standards.
[7] The Ventyx Energy Velocity Suite database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: www.ventyx.com.
[8] The S&P database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: www.capitaliq.spglobal.com.
[9] Throughout this analysis, EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.
[10] The D&B Hoover's online platform includes company records that can contain NAICS codes, number of employees, revenues, and assets. For more information, see: https://www.dnb.com/en-gb/products-and-services/dun-bradstreet-hoovers/.
[11] SBA's table of size standards can be located here: https://www.sba.gov/document/support--table-size-standards.

associated North American Industry Classification System (NAICS) code[12] and SBA size standard. Therefore, it was necessary to identify the specific NAICS code associated with each ultimate parent entity in order to understand the appropriate size standard to apply. Data from D&B Hoover's was used to identify the NAICS codes for most of the ultimate parent entities. In many cases, an entity that is a majority owner of a power plant is itself owned by an ultimate parent entity with a primary business other than electric power generation. Therefore, it was necessary to consider SBA entity size guidelines for the range of NAICS codes listed in Table 1. This table presents an example of the NAICS codes and areas of primary business of ultimate parent entities that are majority owners of potentially affected EGUs in the historical record.[13]

Table 1 SBA Size Standards by NAICS Code

NAICS Codes	NAICS U.S. Industry Title	Size Standards (number of employees)
221111	Hydroelectric Power Generation	750
221112	Fossil Fuel Electric Power Generation	950
221113	Nuclear Electric Power Generation	1,150
221114	Solar Electric Power Generation	500
221115	Wind Electric Power Generation	1,150
221116	Geothermal Electric Power Generation	250
221117	Biomass Electric Power Generation	550
221118	Other Electric Power Generation	650
221121	Electric Bulk Power Transmission and Control	950
221122	Electric Power Distribution	1,100
221210	Natural Gas Distribution	1,150

Note: This table is an example of the NAICS codes that comprised this analysis. For a complete list, please see the accompanying workbook. Based on size standards available at the following link: https://www.sba.gov/document/support--table-size-standards). Source: SBA, 2023.

EPA compared the relevant entity size criterion for each ultimate parent entity to the SBA size standard noted in Table 1. We used the following data sources and methodology to estimate the relevant size criterion values for each ultimate parent entity:

1. **Employment, Revenue, and Assets**: EPA used the D&B Hoover's database as the primary source for information on ultimate parent entity employee numbers, revenue, and assets.[14] In parallel, EPA also considered estimated revenues from affected EGUs based

[12] North American Industry Classification System can be accessed at the following link: https://www.census.gov/naics/.
[13] For a complete list of the NAICS codes associated with this analysis, please see the accompanying workbook.
[14] Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.

on analysis of IPM estimates for the baseline for 2035. EPA assumed that the ultimate parent entity revenue was the larger of the two revenue estimates. In limited instances, supplemental research was also conducted to estimate an ultimate parent entity's number of employees, revenue, or assets.

2. **Population**: Municipal entities are defined as small if they serve populations of less than 50,000.[15] EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination.

Ultimate parent entities for which the relevant measure is less than the SBA size standard were identified as small entities and carried forward in this analysis. Using this analysis, EPA identified 17 percent of the NGCC and 31 percent of the NGCT additions over the historical period were attributed to small entities as summarized in Table 2 below.

Table 2 Historical NGCC and NGCT Additions (2017-present)

Capacity Type	Total Additions (GW)	Total Additions by Small Entities (GW)	Share of Small Entities to Total Build (%)
NGCC	52.8	9.0	17%
NGCT*	6.8	2.1	31%

*Notes: (1) One small entity accounts for 1 GW of these builds (and owns 2.3 GW of currently operating capacity). This entity represents approximately half (16%) of the share of small entities to total build. (2) As the scope of the IRFA is limited to the proposed new source performance standards, this table presents small business impacts for the capacity types of NGCC and NGCT. Small entities also own other capacity types not covered in the scope of the IRFA.

4. Compliance Cost Impact Estimates

In 2035, a new NGCC addition can comply with the proposed rule by implementing efficiency improvements (if it operates at an annual capacity factor of below 50 percent), co-firing hydrogen, or installing CCS. A new NGCT addition can comply with the proposed rule through implementing efficiency improvements (if it operates at an annual capacity factor of below 20 percent) or co-firing hydrogen. The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units.

To attempt to account for each potential control strategy, EPA estimates compliance costs as follows:

[15] The Regulatory Flexibility Act defines a small government jurisdiction as the government of a city, county, town, township, village, school district, or special district with a population of less than 50,000 (5 U.S.C. section 601(5)). For the purposes of the RFA, States and tribal governments are not considered small governments. EPA's *Final Guidance for EPA Rulewriters: Regulatory Flexibility Act* is located here: https://www.epa.gov/sites/default/files/2015-06/documents/guidance-regflexact.pdf.

$$C_{Compliance} = \Delta\ C_{Operating+Retrofit} + \Delta\ C_{Fuel} + \Delta\ R$$

where C represents a component of cost as labeled[16], and Δ R represents the change in revenues, calculated as the difference in value of electricity generation between the baseline case and the rule in in 2035 for projected NGCC and NGCT additions (calculated separately), when the second phase of the NSPS is assumed to be active under the proposal.

Realistically, compliance choices and market conditions can combine such that an entity may actually experience a reduction in any of the individual components of cost. Under the rule, some units will generate less electricity (and thus revenues), and this impact will be lessened on these entities by the projected increase in electricity prices under the rule. On the other hand, those units increasing generation levels will see an increase in electricity revenues and as a result, lower net compliance costs. If entities are able to increase revenue more than an increase in fuel cost and other operating costs, ultimately, they will have negative net compliance costs (or increased profit). Because this analysis evaluates the total costs along each of the compliance strategies laid out above for each entity, it inevitably captures gains such as those described. As a result, what we describe as cost is a measure of the net economic impact of the rule on small entities.

For this analysis, EPA used IPM output to estimate costs based on the parameters above, at the unit level. These impacts were then summed for each small entity, adjusting for ownership share. Net impact estimates were based on the following: operating and retrofit costs, and the change in fuel costs or electricity generation revenues under the proposed rule relative to the baseline. These individual components of compliance costs were estimated as follows:

1. **Operating and retrofit costs** ($\Delta\ C_{Operating+Retrofit}$): The change in operating and retrofit costs under the proposed rule was estimated by taking the difference in projected FOM, VOM and retrofit capital expenditures between the IPM estimates for the proposed rule and the baseline for the NGCT and NGCC additions projected by the model.

2. **Fuel costs** ($\Delta\ C_{Fuel}$)**:** The change in fuel expenditures under the proposed rule was estimated by taking the difference in projected fuel expenditures between the IPM estimates for the proposed rule and the baseline for the NGCT and NGCC additions projected by the model.

3. **Revenue:** To estimate the value of electricity generated, the projected level of electricity generation is multiplied by the regional wholesale electricity price ($/MWh) projected by IPM, and the accredited capacity multiplied by the projected regional capacity price projected by IPM for the NGCT and NGCC additions projected by the model. The difference between this value under the baseline and the proposed rule constitutes the estimated change in revenue.

Once the costs of the rule were calculated in the manner described above, the costs attributed to small entities were calculated by multiplying the total costs to the share of the historical build attributed to small entities. These costs were then shared to individual entities using the ratio of their build to total small entity additions in the historical dataset.

Under the compliance modeling for the proposal, NGCT additions and dispatch are higher as a result of reductions in existing coal-fired EGU capacity and generation. As a result,

[16] Retrofit costs include the costs of installation of CCS.

economic NGCT additions experience negative compliance costs in 2035. Under the compliance modeling for the proposal, economic NGCC additions dispatch at lower levels relative to the baseline when the second phase of the NSPS is active. As such, they experience positive compliance costs.

As indicated above, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by EPA on compliance with the RFA and is consistent with guidance published by the SBA's Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities. The potential impacts, including compliance costs, of the proposed rule on NGCCs owned by small entities are summarized in Table 3. All costs are presented in 2019 dollars. EPA estimated the annual net compliance cost to small entities to be approximately $25.6 million in 2035.

Based on feedback from the panel, EPA revised its small business assessment to incorporate the final SBA guidelines (effective March 17th 2023) when performing the screening analysis to identify small businesses that have built or have planned/committed builds of combustion turbines since 2017. EPA also treated additional entities within this subset as small based on feedback received during the panel process. The net effect of these changes is to increase the total compliance cost attributed to small entities, and the number of small entities potentially affected.

Table 3 Projected Impact of the Proposed Rule on Small Entities in 2035

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost ($2019 millions)	Number of Small Entities with Compliance Costs >=1% of Generation Revenues
Private	6	15.0	0
Co-op	3	10.2	0
Municipal	1	0.4	0
Total	**10**	**25.6**	**0**

Source: IPM analysis

Note: This analysis does not account for the addition of the more stringent policy options on which EPA sought comment.

EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Of the 10 entities that own NGCC units considered in this analysis, none are projected to experience compliance costs greater than or equal to 1 percent of generation revenues in 2035.

5. Caveats and Limitations

As outlined above, the analysis of the potential impacts on small businesses from this rule was derived from estimates of projected national compliance costs of the NPRM primary proposal. These aggregate national compliance costs were then apportioned to small entities identified based on the analysis of historical and planned/committed build patterns. Therefore, if the future share of builds varies from the identified shares, this could result in differential impacts than those calculated in this analysis.

EPA's modeling is based on expert judgment of various input assumptions for variables whose outcomes are uncertain. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls and new capacity construction costs to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions for electric generating units (EGUs). The annualized cost of the rules for EGUs, as quantified here, is EPA's best assessment of the cost of implementing the rules for the power sector. These costs are generated from rigorous economic modeling of anticipated changes in the power sector due to implementation of the rule.

There are several key areas of uncertainty related to the electric power sector that are worth noting as outlined below. Significant changes to one or more of these assumptions could result in a different estimate of compliance costs and therefore the finding of no SISNOSE for this action. In particular, EPA received significant comments on the price, availability, and associated infrastructure necessary for hydrogen. A higher assumed hydrogen price would likely affect compliance costs for existing and new turbines subject to the regulations.

- Electric demand: The analysis includes an assumption for future electric demand. This is based on the Annual Energy Outlook (AEO) 2021 reference case with incremental demand from EPA's Office of Transportation and Air Quality (OTAQ) on the books rules that are not captured in AEO 2021 reference case projections.[17] To the extent electric demand is higher or lower, it may increase/decrease the projected future composition of the fleet.

- Natural gas supply and demand: The recent run up in fuel costs is assumed to abate by the first run year in this analysis (2028). Large increases in supply over the last few years, and relatively low prices, are represented in the analysis for subsequent run years. To the extent prices are higher or lower, it would influence the use of natural gas for electricity generation and overall competitiveness of other EGUs (e.g., coal and nuclear units). The natural gas assumptions used in this analysis do not include the impacts of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.

- Longer-term planning by utilities: Many utilities have announced long-term clean energy and/or climate commitments, with a phasing out of large amounts of coal capacity by 2030 and continuing through 2050. These announcements, some of which are not legally binding, are not necessarily reflected in the baseline, and may alter the amount of coal capacity projected in the baseline that would be covered under this rule.

- Inflation Reduction Act (IRA): The IRA was passed in August of 2022. In order to illustrate the impact of the IRA on this rulemaking, EPA included a baseline that

[17] For details, see Chapter 3 of the IPM documentation available at: https://www.epa.gov/power-sector-modeling.

incorporates key provisions of the IRA as well as imposing the proposed rules as modeled in this RIA on that baseline. However, additional effects of the IRA beyond those modeled in this RIA could result in a change in projected system compliance costs and emissions outcomes.[18]

- Hydrogen production: 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[19] associated with the production of the hydrogen, nor any incremental electricity demand associated with its production.[20] 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 NO_X emission rates at higher levels of hydrogen blending.[21] For details on hydrogen modeling assumptions, please see Section 3.6 of the RIA for this rulemaking.

6. Projected Reporting, Recordkeeping, and Other Compliance Requirements

The information to be collected for the proposed NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards.[22] Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents are fossil fuel-fired electric utility steam generating units. Few, if any, of the facilities in the United States are owned or operated by state, local, tribal or the Federal government. The regulated facilities are privately owned for-profit businesses. The requirements in this action result in industry recordkeeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing

[18] For details of IRA representation in this analysis please see IPM documentation, available at: https://www.epa.gov/power-sector-modeling.
[19] IPM does not track upstream emissions for any modeled fuels.
[20] Potential impacts associated with hydrogen production and utilization are discussed in sections VII(F)(3) and XIV(E)(3) of the proposal preamble. See 88 FR 33240 (May 23, 2023). These include water use in hydrogen production, combustibility, and potential increased NO_X emissions from combustion of higher percentages of hydrogen in natural gas blends. Analysis in the RIA did not assess these potential impacts, nor the potential impacts of hydrogen gas release on climate or air quality through atmospheric chemical reactions.
[21] For details on the possible increases in NOx emission rates at higher levels of hydrogen blending, see U.S. EPA. *Hydrogen in Combustion Turbine Electricity Generating Units Technical Support Document.* May 2023. Docket ID No. EPA-HQ-OAR-2023-0072-0059.
[22] U.S. EPA. Information Collection Request (ICR) Supporting Statement. New Source Performance Standards Subpart TTTTa. April 2023. Docket ID No. EPA-HQ-OAR-2023-0072-0020.

initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and training personnel to be able to respond to the collection of information.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements is approximately 110 labor hours, with an annual average cost of about $14,000. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

7. Related Federal Rules

There are additional air regulations that apply to certain equipment in the power sector. These rules, listed below, address criteria air pollutants, primarily particulate matter (PM), nitrogen oxides (NO_x), and sulfur dioxide (SO_2) and air toxics, primarily mercury, acid gas hazardous air pollutants (HAP) and non-mercury HAP metals.

- Electric Utility Steam Generating Units - 40 CFR part 60, subpart Da (PM, SO_2, NO_X)
- Stationary Combustion Turbines - 40 CFR part 60, subpart GG and subpart KKKK (NO_X), 40 CFR part 63, subpart YYYY (HAP)
- Coal- and oil-fired EGUs - 40 CFR part 63, subpart UUUUU (Mercury, HAP, and non-mercury metals)

In addition, EPA's Class VI Underground Injection Program regulates geologic sequestration wells under the Underground Injection Control (UIC) program of the Safe Water Drinking Act. EPA's GHG Reporting Program requires reporting and public disclosure of geologic sequestration activity, as well as implementation of rigorous monitoring, reporting, and verification of geologic sequestration.

Aside from the EPA, other Federal agencies have jurisdiction over the power sector.

- The Department of Energy addresses energy, environmental, and nuclear challenges through transformative science and technology solutions.
- The Federal Energy Regulatory Commission (FERC) within the Department of Energy regulates the transmission and wholesale sale of electricity in interstate commerce.
- The Pipeline and Hazardous Materials and Safety Administration (PHMSA) within the Department of Transportation issues safety regulations for existing and new CO_2 pipelines.

8. Regulatory Flexibility Alternatives

The EPA convened a Small Business Advocacy Review (SBAR) Panel to obtain recommendations from small entity representatives (SERs) on elements of the regulation. The Panel identified significant alternatives for consideration by the Administrator of the EPA, which were summarized in a final report. A copy of the full SBAR Panel Report is available in the rulemaking docket (EPA-HQ-OAR-2023-0072). Based on the Panel recommendations, the EPA is taking comment on regulatory alternatives that could accomplish the stated objectives of the Clean Air Act while minimizing any significant economic impact of the proposed rule on small entities. Discussion of those alternatives is provided below.

Subcategories: Small businesses expressed concerns that control requirements on rural electric cooperatives may be an additional hardship on economically disadvantaged communities and small entities. SERs stated that EPA should further evaluate increased energy costs, transmission upgrade costs, and infrastructure encroachment which are concrete effects on the disproportionately impacted communities. Additionally, SERs stated hydrogen and CCS cannot be BSER because they are not commercially available and viable in very rural areas.

As described in the preamble to the supplemental proposal, EPA is soliciting comment on potential exclusions or subcategories for small entities that would be based on the class, type, or size of the source and be consistent with the Clean Air Act. EPA is also soliciting comment on whether rural electric cooperatives and small utility distribution systems (serving 50,000 customers or less) can expect to have access to hydrogen and CCS infrastructure, and if a subcategory for these units is appropriate. The EPA believes this information will help us further understand the impacts on small businesses.

These solicitations for comment are responsive to SER's statements and concerns about lack of infrastructure for rural electric cooperatives. The EPA believes the solicitations for comment will help continue the dialogue with small entity stakeholders to help the EPA more fully understand the impacts on and challenges for rural electric cooperatives.

Mechanism for reliability relief. Throughout the SBAR Panel outreach, SERs expressed concerns that the proposed rule will have significant reliability impacts, including that areas with transmission system limitations and energy market constraints risk power interruption if replacement generation cannot be put in place before retirements. SERs recommended that Regional Transmission Organizations (RTOs) be involved to evaluate safety and reliability concerns.

SERs additionally stated that the proposed rule relies on the continued development of technologies not currently in wide use and large-scale investments in new infrastructure and pushes these technologies significantly faster than the infrastructure will be ready and sooner than they can justify investment to their stakeholders and ratepayers. SERs stated that this is of particular concern for small entities that are retiring generation in response to other regulatory mandates and need to replace that generation to continue serving their customers.

As described in the preamble to the supplemental proposal, the EPA is soliciting comment on potential mechanisms for reliability relief. Such mechanisms should be easily implementable and straightforward to address electric reliability concerns. The EPA is additionally soliciting comments on other mechanisms in the event RTO, ISO or other relevant authorities identify reliability issues. The EPA is also requesting comment on phase-in considerations for small entities, implementation flexibilities for certain circumstances that may be outside the control of affected sources, and lessons learned from past reliability mechanisms.

The EPA believes this information will help us further understand the impacts on small businesses.

These solicitations for comment are responsive to SER's statements and concerns about reliability. The EPA believes the solicitations for comment will help continue the dialogue with small entity stakeholders to help the EPA more fully understand the impacts and reliability challenges on small businesses.