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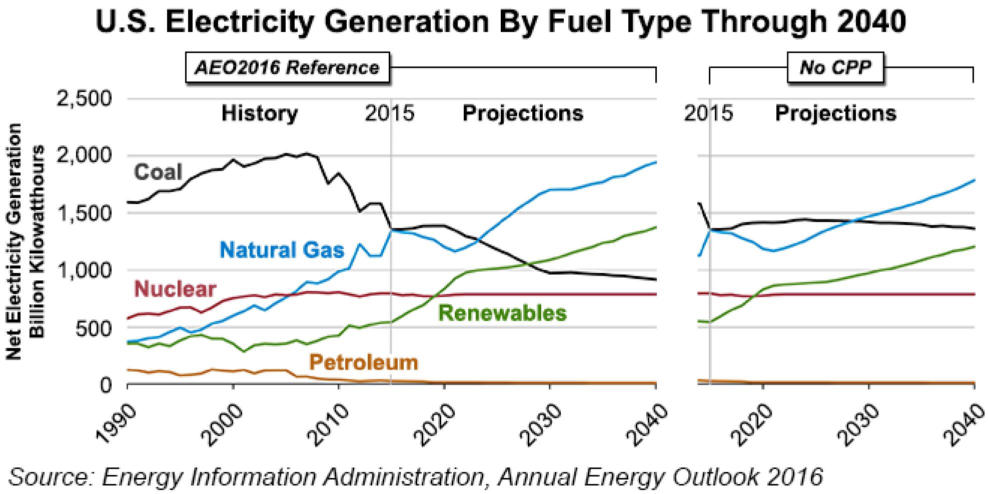
U.S. Environmental Protection Agency
National Center for Environmental Economics
Office of Policy
1200 Pennsylvania Avenue, NW
Docket ID No. EPA-HQ-OA-2018-0107
Mailcode 1809T
Washington, D.C. 20460

Subject: Comments on the U.S. Environmental Protection Agency's Proposed Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Proposed Revisions to Emission Guideline Implementing Regulations; and Proposed Revisions to the New Source Review Program (83 Fed. Reg. 44,746 (Aug. 31, 2018).

Dear Sir/Madam:

The American Petroleum Institute ("API") provides these comments on the U.S. Environmental Protection Agency's ("EPA's" or "the Agency's") Proposed Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Proposed Revisions to Emission Guideline Implementing Regulations; and Proposed Revisions to the New Source Review Program ("Proposed ACE Rule"). API represents over 625 oil and natural gas companies. These companies are leaders of a technology-driven industry that supplies most of America's energy, supports more than 10.3 million jobs and nearly 8 percent of the U.S. economy, and, since 2000, has invested more than $3 trillion in U.S. capital projects to advance all forms of energy, including alternatives.

API members are potentially impacted by this proposal in many ways. First and foremost, API members produce natural gas, which, in 2015, surpassed coal as the primary source of domestic electricity generation, and is expected to remain the primary source of electricity generation for the foreseeable future.[1]



Although EPA is not herein proposing to regulate natural gas-fired Electric Utility Generating Units ("EGUs"), API believes it is important to provide these comments to describe the vital role of natural gas in power generation and to ensure that the administrative record reflects that natural gas is reliable, abundant, affordable, and environmentally beneficial. API also wants to ensure that EPA's proposed regulatory text clearly and unambiguously excludes combined heat and power units and simple cycle turbines that are either present at, or important to, API member facilities.

API members are also potentially impacted by this proposal because they are energy users. Petroleum refineries are the nation's second-highest industrial consumer of energy.[2] In order to provide the nation with critical fuels, petroleum products, and chemicals in a cost-effective manner, access to clean, reliable, and affordable energy is critical.

Finally, API members are interested in this proposal in the event EPA relies upon the framework for a potential future greenhouse gas ("GHG") standard applicable to natural gas-fired EGUs or to entirely distinct sectors, such as the refining and petrochemical manufacturing industry. We believe there are a substantial number of differences among the sectors, including industry economics, geography, federal and State incentives, transportation networks, ownership structures, foreign competitors, profit margins, customer bases, global competition, and trading issues.

Indeed, it is API's interest in EPA's adoption of clear, reasonable, and legally sound regulation that has informed our advocacy in this effort, and in all prior efforts to regulate GHG emissions from EGUs. As before, API's comments are focused on ensuring that EPA adopts regulatory

[1] https://www.naturalgasintel.com/articles/106945-us-becoming-net-natgas-exporter-by-2017-eia-predicts
[2] https://www.eia.gov/energyexplained/?page=us_energy_home

approaches that are clear and consistent with the Agency's governing statutes. API is not herein refuting the existence of climate change or arguing against all regulation of GHG emissions. API and its member companies consider climate change a very important issue and are engaging constructively to address this complex global challenge.

I. SUMMARY OF COMMENTS

Natural gas provides a clean, reliable, and affordable means of producing electricity. Given its abundance and affordability, natural gas is now the primary source of domestic electricity generation, and is expected to remain so for the foreseeable future. The dominant role of natural gas in electricity production provides benefits to consumers as well as to the environment. Domestic industrial electricity prices are 30-50 percent lower than our global rivals. At the same time, natural gas-fired power production has reduced domestic CO_2 emissions to 25-year lows, while providing the on-demand "dispatchable" power necessary to foster the expansion of clean but intermittent renewable power sources.

Natural gas is also a reliable and resilient power source. The physical operations of natural gas production, transmission, and distribution make the system inherently reliable and resilient. Disruptions to natural gas service are rare. When they do happen, a system disruption does not necessarily result in an interruption of scheduled deliveries of natural gas supply because the natural gas system has many ways of offsetting the impact of disruptions.

Given these favorable attributes, API supports EPA's proposal to exclude natural gas-fired EGUs from the "affected facilities" that will be subject to regulation under the Proposed ACE Rule. Natural gas-fired stationary combustion turbines are already highly efficient, and any further emission reductions would likely be modest in size and prohibitively expensive. For similar reasons, API also supports EPA's proposed exclusion of combined heat and power ("CHP") units and simple cycle turbines. These types of units are important to efficient and reliable power generation and should not be considered "affected sources." As such, API requests that EPA provide further clarifying language to ensure that there is no question that CHP units and simple cycle turbines are excluded from this rulemaking.

API also supports EPA's proposed evaluation of the "best system of emission reduction" ("BSER") as limited to those systems of greenhouse gas emission reduction that are applied to or are at the existing stationary source (*i.e.*, within the fence line of the EGU). API opposed the expansive reading of BSER that EPA adopted in the Clean Power Plan ("CPP"), and therefore supports the interpretation of Section 111(d) as set forth in the proposal. API also believes that EPA possesses ample authority to revisit the Agency's expansive interpretation of BSER in the CPP and to set forth the new, more customized approach identified here.

EPA's proposed evaluation of BSER also appropriately limits the Agency's role to the provision of non-binding guidance and preserves the primary role of States in establishing standards of performance for specific facilities or groups of facilities based on their own unique attributes. EPA's proposed revisions to the Agency's emissions guideline implementing regulations reflect this important State role and Congressional intent in enacting Section 111(d). API believes that States using the flexibility provided in this proposal can, and should, consider CHP units, natural gas combined cycle units, natural gas co-firing in coal-fired EGUs, and carbon capture and storage as they set State-specific standards of performance under Section 111(d).

API also believes that EPA has appropriately recognized New Source Review ("NSR") permitting as a significant obstacle to efficiency improvements. Because these adverse impacts are present in other sectors, such as the refining and petrochemical manufacturing sectors, however, API recommends that EPA expand the proposed NSR changes to include all industry sectors. API also believes there are several ways in which the Agency could minimize or eliminate major NSR's disincentives for all industrial sources undertaking energy-efficiency projects, in lieu of adding an upfront hourly emissions test to the NSR regulations. For instance, we believe that EPA can and should expand the routine maintenance, repair and replacement exemption, further clarify the actual-to-protected-actual test, and develop additional guidance on Plantwide Applicability Limits ("PALs") that provides facilities greater flexibility to make HRI to equipment.

Finally, API supports the key elements of EPA's approach to assessing the potential impacts of its proposed rulemaking. We believe that the Regulatory Impact Analysis ("RIA") that accompanied EPA's proposal appropriately considered a range of scenarios, explained the bases for EPA's assumptions, transparently disclosed the sources and extent of uncertainty, and presented the data in a clear and focused manner. The RIA is a substantial improvement from the RIA EPA used for the CPP, and therefore provides a far better basis for evaluating the rationality of the proposal and the proportionality of costs and benefits.

II. DETAILED COMMENTS

a. <u>The Importance of Natural Gas in Power Generation</u>

America is now the world's leading producer and refiner of oil and natural gas, a reality that was unimaginable just a decade ago. We have transitioned from an era of energy scarcity and dependence to one of energy abundance and security. The U.S. has been able to take advantage of new technology to safely tap into energy resources that were once thought inaccessible; in fact, current natural gas resources could meet up to 100 years[3] of current demand. Renewable energy is certainly a growing and important part of our economy's energy mix, but natural gas has led and will continue to lead the way in meeting our growing energy needs. In fact, natural gas produces about one-third of America's electric power and generated more electricity than any other fuel source in 2017.[4]

The developments of the past decade have brought cost savings for American consumers, good paying jobs, renewed opportunities for U.S. manufacturing, a stronger economy, and greater national security. Harvard Business School finds domestic industrial electricity prices are 30-50 percent lower than our global rivals.[5] These lower prices has contributed to energy abundance that helps cut energy and material costs for American manufacturers and increases their

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[3] https://dailyenergyinsider.com/news/5546-american-petroleum-institute-releases-report-benefits-oil-natural-gas-industry/

[4] https://www.eia.gov https://www.hbs.edu/competitiveness/Documents/america-unconventional-energy-opportunity.pdf/tools/faqs/faq.php?id=427&t=3 (accessed 10/30/18).

[5]

competitiveness globally.[6] Notably, these rapid increases in production did not come at the expense of environmental protection. In fact, record U.S. production and refining is happening alongside greater environmental progress.

Even in light of the growing renewable energy industry, natural gas remains vital to sustaining this progress. Natural gas is capable of providing on-demand “dispatchable” power that can follow any real-time changes in electrical load. Natural gas powered generation can also provide the necessary grid stabilizing attributes that are increasingly important with the integration of more intermittent, renewable energy. While sunshine and wind are dependent on weather and can be inconsistent, natural gas can be relied upon as an affordable, economically efficient power to stabilize the grid.[7] Clean and abundant natural gas is a key driver of reliability in power generation. With such a clean, reliable and, affordable source of energy, we do not have to sacrifice economic growth for environmental progress.

1. Environmental Benefits of Natural Gas (C-1)

The environmental benefits of natural gas are undeniable. From 2005 to 2016, the U.S. increased natural gas consumption for electricity generation by 70%, while CO_2 emissions from electricity generation fell by 24.6 %.[8] Much of these CO_2 reductions are attributable to increased natural gas use because natural gas combustion emits about half as much CO_2 as coal combustion. Combustion of natural gas also results in lower emissions of mercury, particulate matter, nitrogen oxides, and sulfur dioxide.

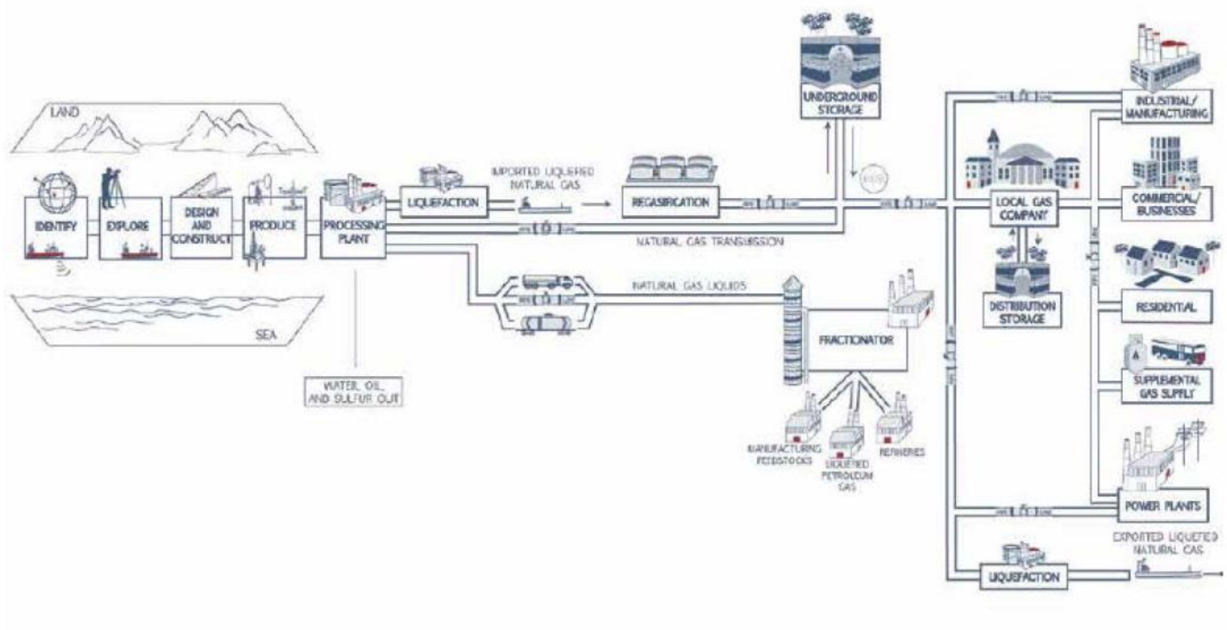
In addition to the environmental benefits associated with the cleaner combustion of natural gas, natural gas is being produced in an increasingly effective and efficient manner. Emissions from natural gas systems have fallen 16.3% since 1990, despite a 53% rise in natural gas production.[9] The industry has adopted voluntary practices to reduce maintenance-related releases of the greenhouse gas methane by installing improved controllers and pumps, and expanding monitoring, leak inspection, and data collection programs. The industry also works with universities and nongovernmental organizations to monitor methane emissions and find ways to decrease them, in addition to investing $108.2 billion between 2000 and 2016 on zero- and low-carbon technologies in all sectors of the oil and natural gas industry.

2. Natural Gas is Reliable

The United States has abundant natural gas resources that enable our industry to provide a safe, and reliable fuel source for electricity production, transportation, manufacturing, and other uses. In only a few years’ time, the U.S. has become the largest producer of natural gas in the world. Estimates of the gas resource base have more than doubled in the past decade.[10] Since 2010,

[6] https://www.api.org/oil-and-natural-gas/energy-primers/americas-natural-gas
[7] http://energytomorrow.org/~/media/Files/Policy/%20SOAE-2017/State-Of-American-Energy-Report-2017-Low.pdf?la=en
[8] http://www.energyinfrastructure.org/~/media/energyinfrastructure/images/pipeline/related-docs/api-aopl-pipeline-safety-report-high.pdf
[9] https://www.eia.gov/dnav/ng/hist/n9050us2a.htm
[10] *See* Potential Gas Committee *Biennial Report of Potential Supply of Natural Gas in the United States*, (December 31, 2014), 2015.

production has grown almost 30%, with government forecasts calling for production to once again reach the record of near 75 billion cubic feet per day this year.[11] This record production reaches natural gas users through a network of pipelines that are extensive, reliable, and expanding every year.



Source: The American Petroleum Industry, Oil and Natural Gas Industry Preparedness Handbook, 2016.

Demand for natural gas in the power sector has increased, driven by natural gas's low-carbon emissions, retirements of older coal-fired plants, the comparatively low cost and small footprint of natural gas-fired power plants, and the on-demand "dispatchable" power on which the expansion of renewable energy industry depends.[12] Because of these advantages, natural gas is poised to become an even more important part of States' energy portfolios as they seek to meet State clean energy objectives.

Yet, with the forecasted growth in power demand, some—particularly those unfamiliar with natural gas operations and contractual practices—question the ability of natural gas to continue to reliably serve this market. These reliability concerns, however, overlook the physical characteristics of natural gas, as well as operational industry practices that provide an extremely high level of reliability and resiliency for gas customers. The physical operations of natural gas production, transmission, and distribution make the system inherently reliable.

Disruptions to natural gas service are rare. When they do happen, a disruption of the system does not necessarily result in an interruption of scheduled deliveries of natural gas supply because the

[11] See EIA *Short Term Energy Outlook*, May 2017 and EIA Natural Gas Summary
[12] See Leidos (formerly SAIC), Comparison of Fuels for Power Generation, 2016, available here.

natural gas system has many ways of offsetting the impact of disruptions. As noted in a report from MIT:[13]

> The natural gas network has few single points of failure that can lead to a system-wide propagating failure. There are a large number of wells, storage is relatively widespread, the transmission system can continue to operate at high pressure even with the failure of half of the compressors, and the distribution network can run unattended and without power. This is in contrast to the electricity grid, which has, by comparison, few generating points, requires oversight to balance load and demand on a tight timescale, and has a transmission and distribution network that is vulnerable to single point, cascading failures.

Certain inherent characteristics of natural gas are important to its reliability. Unlike electricity that travels at the speed of light and flows along a path of least resistance, natural gas moves through the transportation system with the use of compressors that pressurize the gas. In sharp contrast to electricity, natural gas physically moves slowly through a pipeline at an average speed of 15-20 miles per hour, and its flow can be controlled. This allows time for pipeline operators to manage the flow of natural gas and to adjust their operations in the unlikely event of a disruption. Because of the pipeline operators' ability to manage natural gas on their transportation systems, a failure at a single point on the system typically has only a localized effect.[14]

In addition, natural gas production comes from diverse geographic areas spread across many U.S. States and Canada. This abundant and stable supply helps ensure that overall natural gas production is rarely impacted by isolated local or regional events. In the U.S. today, there are more than a half million producing gas wells[15] spread across 30 States.[16] There are hundreds of natural gas producers, and even the largest U.S. producer contributes less than 5 percent to total domestic supply.[17] This diversified supply is connected to a pipeline network that is extensive and expanding.

Another valuable and somewhat unique characteristic of natural gas is its ability to be stored after production. Natural gas is most commonly stored underground in depleted aquifers and oil and gas fields, as well as in salt caverns. It can also be stored above ground in storage tanks as liquefied natural gas ("LNG") for use at import and export facilities and at peak shaving plants, or as compressed natural gas ("CNG") for industrial and commercial uses. In addition to the importance of storage as a supply cushion, storage also provides vital operational flexibility in the event of constraints in the pipeline and distribution network, as storage facilities are widely dispersed on those networks.

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[13] Massachusetts Institute of Technology, Lincoln Laboratory, "Interdependence of the Electricity Generation System and the Natural Gas System and Implications for Energy Security," May 15, 2013.

[14] More detail about the physical, operational characteristics of the natural industry segments can be found in the Appendices to the 2011 Southwest Cold Weather Event report prepared by the staffs of FERC and NERC. Report on Outages and Curtailments During Southwest Cold Weather Event of February 1-5, 2011 (August 2011), Appendices 8-10 ("Southwest Cold Weather Report").

[15] https://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm.

[16] https://www.eia.gov/tools/faqs/faq.php?id=46&t=8

[17] http://www.ngsa.org/wp-content/uploads/2017/03/Top-40-2016-4th-quarter.pdf

While API supports EPA's proposal to refrain from identifying generation-shifting measures as BSER, we do not agree that the Agency appropriately justified this approach, in part, on concerns over baseload reliability and the potential for natural gas price volatility.[18] A new report, commissioned by API and conducted by the Brattle Group[19], outlines some key reliability challenges and defines several crucial attributes that help maintain and strengthen system reliability. In defining these attributes and scoring their applicability to different fuel types, the report highlights natural gas's unique ability to support grid operations across the board. The tangible reliability benefits offered by flexible power sources—like natural gas—include the following reliability attributes:

- Generation Capability: No attribute is more fundamental to system requirements than the ability to generate electrical energy.
- Dispatchability: Dispatchable resources have the ability to change their output or consumption levels in response to an order by the system operator. While virtually all resources are dispatchable to some degree, some have greater capabilities than others and require shorter lead times.
- Security of Fuel Supply: Security of fuel supply measures the dependability of a resource's energy inputs, or fuel.
- Start Times and Ramp Rates: Closely related to dispatchability, start times and ramp rates determine the speed at which resources can respond to system operators' orders to increase and decrease electricity delivered to the grid.
- Inertia and Frequency Response Capability: Inertia and frequency response are attributes of resources that help the system meet the requirement to maintain frequency stability.
- Reactive Power Capability: The ability to provide reactive power is an attribute necessary for meeting the system's requirement to maintain voltage within certain limits to prevent generator operation malfunctions or, in the worst case, cascading blackouts.
- Minimum Load Level: A resource's minimum load level describes the lowest level of electrical output the resource can continuously send to the grid.
- Black Start Capability: Black start capability is the ability of a power plant to restart without relying on the transmission network to deliver power.
- Storage Capability: Resources with the attribute of storing electricity help the system meet multiple requirements including meeting bulk demand, following load or net load, and maintaining frequency stability, but not all resources with the ability to store electricity contribute to meeting all of the requirements.
- Proximity to Load: The ability to site resources close to load is an attribute that helps the system meet bulk demand and maintain voltages. Resources that are close to load that also have the ability to generate power, reduce transmission losses and transmission congestion.

[18] See 83 Fed. Reg. at 44,754.
[19] http://files.brattle.com/files/7351_diversity_of_reliability_attributes.pdf

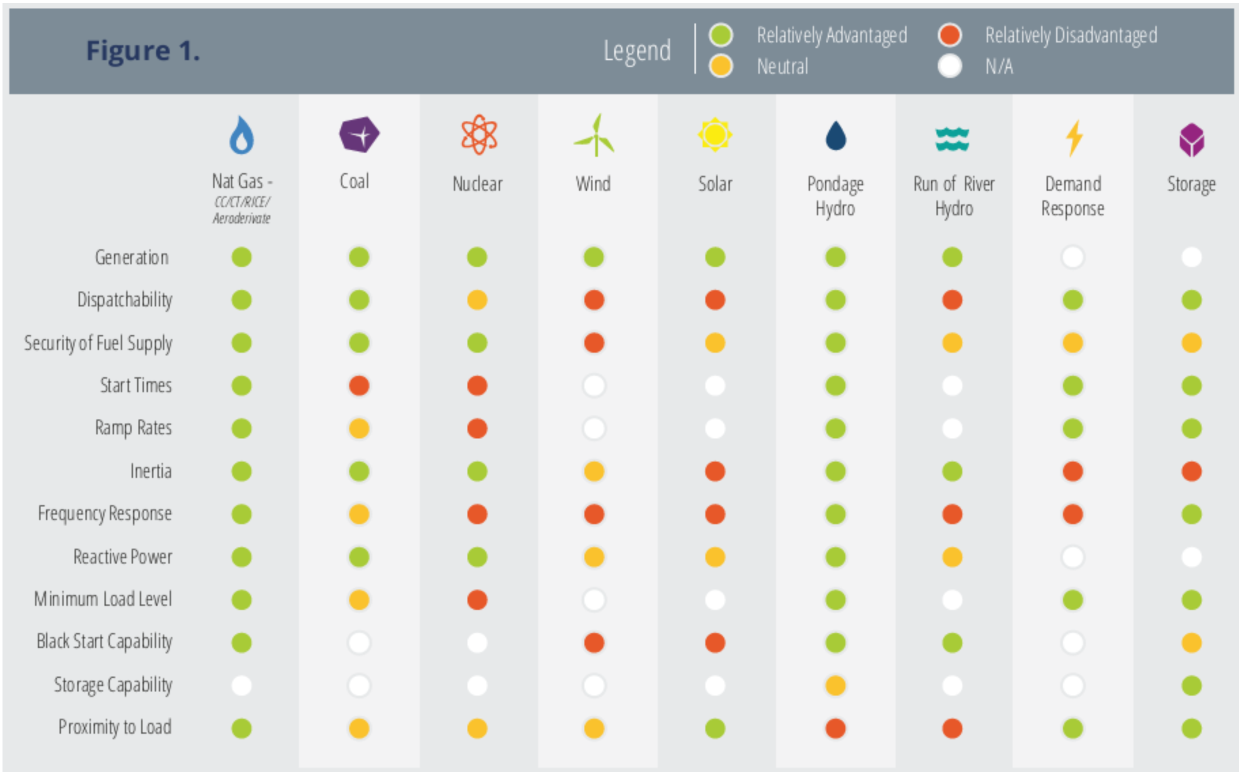

Figure 1[20]

2. Natural Gas is Resilient

The natural gas supply system is also resilient because it is not particularly vulnerable to weather-related events. A newly released report from the Natural Gas Council demonstrates the resiliency of our nation's natural gas industry – even in the face of extreme weather events or direct threats to the system, whether physical or cyber.[21] The report – which examined the industry's preparation and actions during extreme conditions like the January 2018 "bomb cyclone" as well as hurricanes Harvey and Irma – determined that the natural gas industry is not susceptible to wide-spread failure from a single point of disruption due to a number of factors:

- The dispersion of production and storage;
- Redundant characteristics from the extensive integrated pipeline and distribution network;
- A physical configuration which limits vulnerability to weather-related events;
- Robust cyber and physical security protocols that minimize disruptions from manmade or computer threats; and,

[20] https://www.api.org/news-policy-and-issues/blog/2017/10/04/in-power-generation-natural-gas-defines-reliability
[21] Smead, Richard G., *Weather Resilience in the Natural Gas Industry: The 2017-2018 Test and Results (RBN Energy, LLC.*, August 2018).

- A resilient, interconnected system that allows it to come back on line quickly in the rare case of a disruption.[22]

The operation of the entire natural gas system – production, transmission, distribution, and storage – is highly flexible with strong elasticity characteristics. Modern infrastructure relies on control systems to help monitor, and in some cases operate the pipelines and its components to move the product in a reliable, efficient, and effective manner. Operators manage the internal pressure of the delivery system by controlling the amount of natural gas entering and leaving the system. The process of increasing or decreasing pressure happens relatively slowly in a natural gas system because of the compressible nature of the gas. This compressibility lessens the immediacy of impact and increases the probability of detection. Layered onto this control system architecture are overpressure protection devices, which kick-in should the unlikely need arise to prevent the internal gas pressure from threatening the pipeline's integrity.

Other characteristics of the natural gas system contribute to its historical operational resilience. The natural gas transportation network is composed of an extensive network of interconnected pipelines that offer multiple pathways for rerouting deliveries in the unlikely event of a physical disruption. In addition, pipeline capacity is often increased by installing two or more parallel pipelines in the same right-of-way (called pipeline loops), making it possible to shut off one loop while keeping the other in service. In the event of one or more compressor failures, natural gas pipelines can usually continue to operate at pressures necessary to maintain deliveries to pipeline customers, at least outside the affected segment. "Line pack"[23] in the pipelines can be used, if necessary, to provide operational flexibility.

Similarly, producers use various methods to help ensure operational continuity. Because producers have an economic incentive to continue to flow gas out of the producing field at a constant rate, many techniques are in place to help ensure that operations continue, or that any disruption is minimized when a problem arises. While not always possible, producers often rely on more than one processing plant or pipeline rerouting options in a production area, especially when handling a significant level of production. In the unlikely event of an unavoidable supply disruption at a well or in a field, producers have many other options to balance their supply commitments, including increasing production in other areas or using what natural gas they have in storage.

While there are physical constraints on natural gas' ability to serve the entire electrical system — which could and should be addressed with a nationwide commitment to infrastructure investment, it is simply implausible to suggest that the need for increased natural gas transmission pipelines amounts to a lack of reliability. In fact, the opposite is true. The reliability and resilience

[22] Smead, Richard G., *Weather Resilience in the Natural Gas Industry: The 2017-2018 Test and Results (RBN Energy, LLC.*, August 2018).
[23] Line pack is the volume of natural gas contained within the pipeline network at any given time. It allows gas received in one area of a pipeline system to be delivered simultaneously elsewhere on the system. It can facilitate non-ratable flows and support pipeline reliability as a temporary buffer for imbalances. However, line pack must be kept reasonably stable throughout the system to preserve delivery pressure and system capacity. Thus, line pack neither creates incremental capacity, nor is it a substitute for appropriate transportation contracts.

characteristics of gas have allowed this clean energy resource to earn its share of the market while delivering affordable electricity to consumers across the country.

b. Proposed Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units

With the CAA Amendments of 1970, Congress began requiring EPA to establish emission standards for new sources of air pollution that apply regardless of the source location or the ambient air quality of a particular region. The standard-setting process contained two primary steps. First, Section 111 required EPA to publish and periodically update a list of source categories that "cause[], or significantly contribute[] to, air pollution which may reasonably be anticipated to endanger public health or welfare."[24] Then, for each of these source categories, EPA was required to impose standards on new sources that reflect "the degree of emission reduction achievable through application of the best system of emission reduction achievable through application of the best system of emission reduction ["BSER"]."[25] These New Source Performance Standards ("NSPS") then became the foundation for guidance EPA develops and provides to States for consideration in developing plans to regulate existing sources. While EPA's proposal relates to the latter guidelines—and not NSPS—evaluating the approach to BSER that EPA identifies in the present proposal requires some further understanding of the elements Congress prescribed for the BSER analysis, the definition of the new sources to which to BSER would apply, and the narrow circumstances where EPA could require—or recommend States require—BSER at existing facilities.

- "New Sources" – Section 111 defines a new source as "any stationary source, the construction or modification of which is commenced" after proposal of an NSPS.[26] For purposes of Section 111, and to further the goal of regulating the most emission units as such a source is then referred to as the "affected facility." The term "affected facility" does not appear in the CAA. In EPA's regulations, however, the "affected facility" is the particular piece of equipment or the process to which a performance standard applies.[27] Using that definition, EPA has defined "affected facility" to include everything from a single piece of equipment within the plant to the entire plant itself. Although EPA has discretion to define the "affected facility," it has always been defined as either the source or a unit within the source. Similarly, with the exception of the CPP, EPA has only imposed emissions standards that could be met through technological controls or operational restrictions that could be applied at the source.

- BSER – As stated above, BSER reflects "the degree of emission reduction achievable through application of the best system of emission reduction."[28] While the phrase "degree of emission limitation" refers to a level of performance—as opposed to the application of a specific technology—in practice, the feasibility of the emission limitation is evaluated through the consideration of specific technologies that could be applied at the source.

[24] CAA § 111(b)(1)(A).
[25] CAA § 111.
[26] CAA § 111 (a)(2).
[27] See 40 C.F.R. § 60.2.
[28] CAA § 111.

Indeed, this is the reason for Congress' inclusion of the phrase "adequately demonstrated." To be "adequately demonstrated," the standard must be capable of being met under the most adverse conditions which can reasonably be expected to recur . . ."[29] EPA "may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on crystal ball inquiry."[30]

The BSER analysis also allows consideration of cost, non-air-quality impacts, and energy impacts. In allowing EPA to analyze these additional potential impacts, however, Congress did not prescribe the precise means by which they should be considered. As such, EPA has broad discretion to frame its consideration of costs, non-air-quality impacts, and energy impacts.[31]

- Application of NSPS to Existing Sources - Congress intended these standards, known as NSPS, to prevent deterioration of air quality from the construction of *new* pollution sources. Section 111's focus on new sources was premised on the pragmatic view that it was easier and more cost-effective to design and incorporate new air pollution control equipment during initial construction rather than through costly retrofits.[32] Notwithstanding Section 111's focus on "new sources" of air pollution, Congress allowed for imposition of "new source" standards on existing sources in two narrow circumstances.

  First, Congress recognized that "existing sources" could become "new sources" if they were modified in a way that increased the amount of a pollutant previously emitted or resulted in the emission of an air pollutant not previously emitted."[33] Similarly, Congress recognized that, regardless of the potential for, or extent of, emission increases, sources could be modified to such a degree that they would essentially become reconstructions of new sources within existing source footprints.[34] While these provisions allowed EPA to impose NSPS on existing sources, Congress only allowed these standards to be imposed when the facility would undergo a level of modification that made it less like an existing source for which the requirement to impose new air pollution control equipment is more disruptive and costly, and more like a new source that is amenable to efficient pre-construction design and incorporation of air pollution controls.[35]

  The second way in which Congress allowed for the imposition of performance standards on existing sources is through Section 111(d). Under Section 111(d), EPA may establish emissions guidelines for existing sources in a source category when the EPA has promulgated the NSPS for that category. This program is limited to sources of "designated

[29] *National Lime Ass'n v. EPA*, 627 F.2d 416, 431, n. 46 (D.C. Cri. 1980).
[30] *National Lime Ass'n v. EPA*, at 433.
[31] *Portland Cement Ass'n. v. Ruckelshaus*, 486 F.2d 375, 387 (D.C. Cir. 1973), *cert denied*, 417 U.S. 921 (1974).
[32] *See National Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 783 (D.C. Cir. 1976); *U.S. v. Painesville*, 431 F. Supp. 496, 500, n.6 (N.D. Ohio 1977) (Citing Legislative History of 1970 Amendments), *Aff'd*, 644 F.2d 1186 (6th Cir. 1977).
[33] CAA Sec. 11(a)(1).
[34] CAA Sec. 11(a)(1).
[35] The precise instances when a source is modified or reconstructed for purposes of NSPS are complex and frequently in dispute. This discussion merely notes that the modification/reconstruction provisions are merely of two means by which NSPS can be imposed on existing sources.

> pollutants."[36] Under Agency regulations promulgated under Section 111(d), after EPA promulgates an NSPS that addresses emissions of a "designated pollutant," the Agency then also provides States with emission guidelines for existing sources within the same source category.[37] States must then develop plans to implement standards on existing sources and submit them to EPA for approval. If the State fails to submit a plan deemed approvable by the Agency, EPA can adopt and implement a federal plan for that State.
>
> While Section 111(d) provided a mechanism for extending the reach of NSPS to existing sources, that mechanism was intended to be wielded at the discretion of States. Indeed, the U.S. Supreme Court has acknowledged that Section 111(d) preserves for each State the authority to take "the first cut at determining how best to achieve EPA emissions standards within its domain."[38]

Congress intended EPA's role to be limited to providing States guidance based on the analysis of controls EPA developed in establishing NSPS and providing some level of oversight on the sufficiency of the State programs. Again this fundamental premise is explained by the U.S. Supreme Court: "For existing sources, EPA issues emissions guidelines; in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction."[39]

Clearly, Section 111(d) was not intended as a means to automatically extend NSPS to existing sources or to unreasonably constrain the discretion of States. To interpret Section 111(d) otherwise ignores that, unlike Section 111(b), which provides for direct Agency regulation of sources, Section 111(d) directs EPA to provide States guidance, and States are directed to develop implementation plans. And yet, in the past, EPA has interpreted its Section 111(d) authority and leveraged its oversight authority such that the Agency's non-binding guidance on States were treated as binding standards on sources. The important role for State discretion, which was expressly preserved under Section 111(d), was reduced to decisions over whether to adopt the "standards" directed by EPA or allow EPA to commandeer State authority through imposition of a federal plan.

As discussed further below, API believes that EPA's current regulations under Section 111(d) are inconsistent with the CAA because they pre-date major amendments to the CAA, and because they treat the Agency's guidance as binding, thereby improperly diminishing the discretion Congress preserved for States. For the purposes of this statutory background, API is merely identifying that Congress expressly limited the Agency's role to the provision of guidance identifying BSER that could apply at sources. With this basic statutory framework in hand, it should already be clear that EPA's Proposed Ace Rule is not only a permissible construction of the Section 111, but it is in most respects statutorily mandated.

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[36] "Designated pollutants" are pollutants for which an NSPS has been developed, but which are not criteria pollutants or hazardous air pollutants under Section 112.

[37] 40 C.F.R. Part 60, subpart B.

[38] *Am. Elec. Power Co. v. Connecticut*, 131 S. Ct. 2527, 2539 (2011).

[39] *Id.* at 2537-38.

1. EPA's Proposed Affected Source Determination (C-3, C-4)

API requests that EPA provide some additional clarification on the types of EGUs excluded from the definition of "affected EGUs" potentially subject to regulation under the Proposed ACE Rule. We are most interested in clarifications with respect to EPA's presumed intent to exclude CHP units and stationary source turbines. While API believes EPA intended to exclude these types of EGUs, textual differences between the preamble language and proposed regulatory text create some confusion and risk of inconsistent interpretations that the Agency can, and should, address prior to finalization.

More specifically, the *preamble* to the Agency's proposal suggests that EPA is proposing that "affected EGUs" subject to regulation under the ACE Rule would exclude stationary combustion turbines and integrated gasification combined cycle ("IGCC") units as well as:

> (1) Those units subject to 40 CFR 60 subpart TTTT as a result of commencing modification or reconstruction;
>
> (2) Steam generating units subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis;
>
> (3) Non-fossil units (i.e., units capable of combusting at least 50 percent non-fossil fuel) that have historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;
>
> (4) Units that serve a generator along with other steam generating unit(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit) is 25 MW or less;
>
> (5) Municipal waste combustor unit subject to 40 CFR part 60, subpart Eb; or
>
> (6) Commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC.[40]

In its proposed *regulatory text* for 40 § 60.5780a, EPA states that "affected EGUs" include only certain steam generating units.[41] Specific types of units proposed to be excluded from the definition of an "affected EGU" include:

> (1) An EGU that is subject to subpart TTTT of this part as a result of commencing construction, reconstruction or modification after the subpart TTTT applicability date;

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[40] 83 Fed. Reg. at 44,754-55.

[41] "Steam generating unit" means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment. To be an "affected EGU" the Steam Generating Unit must (1) have commenced construction on or before August 31, 2018; (2) serve a generator connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net (*i.e*., capable of selling greater than 25 MW of electricity); and, (3) have a base load rating (*i.e*., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

(2) A steam generating unit that is, and always has been, subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;

(3) A stationary combustion turbine that meets the definition of either a combined cycle or combined heat and power combustion turbine;

(4) An IGCC unit;

(5) A non-fossil unit (*i.e.*, a unit that is capable of combusting 50 percent or more non-fossil fuel) that has always limited the use of fossil fuels to 10 percent or less of the annual capacity factor or is subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(6) An EGU that is a combined heat and power unit that has always limited, or is subject to a federally enforceable permit limiting, annual net-electric sales to a utility distribution system to no more than the greater of either 219,000 MWh or the product of the design efficiency and the potential electric output;

(7) An EGU that serves a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;

(8) An EGU that is a municipal waste combustor unit that is subject to subpart Eb of this part; or

(9) An EGU that is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

i. CHP Units

Reading the language of the preamble alongside the proposed regulatory text, API believes that EPA clearly intends to exclude CHP units from the "affected facility" definition. The preamble proposes to exclude stationary combustion turbines and integrated gasification combined cycle ("IGCC") units, which would include CHP units utilizing stationary combustion turbines. For stream-generating CHP units, the preamble proposes to provide a specific exclusion when net-electric sales are limited to one-third or less of their potential electric output, or 219,000 MWh or less on an annual basis.

Much of this language is repeated in the proposed *regulatory text* for 40 CFR § 60.5780a, but the regulatory text also expressly excludes: (1) stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine;[42] and (2) combined heat and power units that have always limited, or are subject to a federally enforceable permit, limiting annual net-electric sales to a utility distribution system to no more than the greater of either 219,000 MWh or the product of the design efficiency and the potential electric output.

[42] The Proposal also defined a CHP unit as "an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source." This definition is the same as the definition EPA provided in the CPP.

API believes some of these more explicit references in the proposed regulatory text fall within the scope of the exclusion described in the preamble. For instance, CHP combustion turbines that are specifically discussed in the proposed regulatory text's list of excluded sources are excluded in the preamble's discussion of EPA's proposed decision to not include stationary combustion turbines in the "affected facility" determination. As such, API does not believe the preamble language and regulatory text are inconsistent and, as previously stated, we do believe that EPA is clearly proposing to exclude CHP units from the universe of "affected EGUs" subject to regulation under the ACE Rule. Given the importance of the exclusion for CHP units, however, API requests that EPA harmonize the phraseology in the preamble and proposed regulatory text so that there is no reasonable question that CHP units are not "affected EGUs".

CHP power generation by industrial facilities creates both environmental and economic benefits. By capturing and using waste heat from the production of electricity, CHP units help reduce CO_2 emissions through significant efficiency gains. CHP units produce lower CO_2 emissions and typically are more economic to operate compared to conventional boilers. Because combined generation is more efficient than separate generation of heat and power, EPA has observed that:

> CHP requires less fuel to produce a given energy output, and because less fuel is burned to produce each unit of energy output, CHP reduces the emission of greenhouse gases and other air pollutants. CHP has comparatively lower emissions rates and can be more economic than separate electric and thermal generation.[43]

EPA predicts that an additional 50 GW of power could be deployed by CHP units by 2020, resulting in significant emissions reductions and cost savings.[44] CHP is also a critical component to the U.S. Department of Energy initiative to increase the amount of industrial distributed energy in the United States.

Industrial CHP units also serve a fundamentally different purpose from commercial EGUs. The primary purpose of a CHP unit is to produce thermal and electric energy for an industrial facility. While excess electricity (if available) may be supplied to the grid, industrial CHP units are not intended to provide a majority of the units' energy output to the public power grid. Excluding industrial CHP units recognizes these fundamental differences and creates incentives to increase the capacity of CHP in the United States.

Additionally, industrial CHP units are typically customized to suit the needs of a host facility. As a result, no two CHP units typically balance the output of thermal energy and electricity production in the same manner, and this balance of thermal and electricity production for any particular CHP unit changes with time. The oil and gas industry utilizes CHP in both refining and upstream sectors, and the use of the electricity generated varies significantly by operation and facility. These variations make CHP units unsuitable for uniform nation-wide BSER analyses or standards of performance. It also makes the calculation of thermal energy equivalence (conversion to kWh) impractical for reporting and enforcement purposes.

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[43] 79 Fed. Reg. at 34,982.
[44] See EPA, Combined Heat and Power: Frequently Asked Questions.

Accordingly, API believes that (subject to the clarifications requested above) EPA is appropriately excluding CHP units from the universe of EGUs subject to these proposed regulations. While we support the exclusion of CHP units from EPA's proposed "affected facility" determination, we do not believe, however, that EPA should constrain States in their consideration of CHP units. States should be able to use GHG emission reductions achieved by industrial CHP units as a compliance option, alongside other methods of reducing net GHG emissions.

ii. All Stationary Combustion Turbines

API also requests that EPA provide additional clarification in the proposed regulatory text of the Agency's intended exclusion of all stationary combustion turbines. Although the text of 40 C.F.R. § 60.5780a proposes to exclude stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine, neither the preamble nor the proposed regulatory text appear to provide the requisite definition of "combined cycle" turbines.[45] Moreover, the proposed regulatory text's focus on "combined cycle" turbines can be read to suggest that EPA is not proposing to extend the exclusion to "simple cycle" combustion turbines. This interpretation is inconsistent with EPA's stated intent in the preamble to exclude all "stationary combustion turbines." Significantly, this interpretation is also inconsistent with the CPP, which exempted natural gas-fired simple cycle combustion turbines.

Treating simple cycle turbines as affected EGUs will needlessly reduce the flexibility States need in order to manage their evolving power generation portfolios. Simple cycle turbines play a critical and unique role in providing peaking power and assuring grid reliability. Simple cycle turbines can cold start quickly, easily scale through loads, and start and stop several times per day. As EPA has previously recognized, this flexibility allows simple cycle turbines to fill the unique role of providing gap-filling auxiliary power at times of high demand or when the grid is otherwise under stress.[46] No other form of power generation is capable of filling this role.

Combined cycle turbines are designed for baseload or intermediate load power, meaning that they are very efficient and have a high utilization rate. In contrast, simple cycle turbines are generally only used to provide peaking power. This means that their hours of operation are unpredictable, and they rarely operate at full load, the most efficient operating mode. The larger—and increasing—role that renewable power sources play requires significant support from simple cycle turbines, which can start-up quickly to compensate for highly variable and often intermittent generation from solar and wind facilities. These renewable energy facilities are subject to several factors beyond their control that impact their reliability, including, but not limited to fluctuating wind speeds, cloud cover, and even the approach of birds. As renewable energy takes on a larger share of power generation, the need for reliable and flexible simple cycle turbine operations will only increase.

Because we expect that the Proposed ACE Rule's seemingly disparate treatment for "simple cycle" combustion turbines was inadvertent, API recommends that EPA provide a clarification

[45] As noted above, the proposed regulatory text does include a definition for CHP units.
[46] 79 Fed. Reg. at 34,968 ("The power output from these simple cycle combustion turbines can be easily ramped up and down making them ideal for 'peaking' operations").

that the Agency is excluding all "stationary combustion turbines" and CHP units from the universe of "affected EGUs" subject to regulation under the ACE Rule.

2. EPA's BSER Evaluation Is Appropriately Limited to Systems That Can Be Applied Within the Fence Line (C-2. C-17)

EPA's evaluation of the BSER is appropriately limited to those systems of GHG emission reduction that are applied to or at the existing stationary source (*i.e.*, within the fence line of the EGU), and therefore exclude actions beyond the source itself. API opposed the expansive reading of BSER that EPA adopted in the CPP, and therefore supports the interpretation of Section 111(d) as set forth in the proposal. API also believes that EPA possesses ample authority to revisit the Agency's expansive interpretation of BSER in the CPP and to set forth a new, more customized approach. Federal agencies, including EPA, "have broad discretion to reconsider a regulation at any time."[47] It is therefore enough for EPA to give "a reasoned explanation for [its] change."[48]

More fundamentally, however, EPA's proposed policy shift in this instance is not only permissible, but it is arguably mandated because it aims to replace the CPP's overreaching construction of Section 111(d). Even if the Agency's new statutory construction were not mandated, as discussed below, EPA has provided a reasoned explanation for its present interpretation of Section 111(d) based on the text, purpose, and legislative history of the CAA. This reasoned explanation is rational and clearly justifies EPA's proposed new approach.

i. The Plain Meaning of Section 111(d) Supports EPA's Source-Based Interpretation of BSER (C-17)

The plain meaning of the phrase "through the application of the best system of emission reduction" – which is the "first step" for setting performance standards for each source under Section 111[49] – supports EPA's proposed reading that BSER must be based on source-specific measures for reducing emissions, and not on measures that are separate and remote from the source of emissions. Section 111(d) requires States to "establish standards of performance for any existing source … to which a standard of performance under this section would apply if such existing source were a new source."[50] The CAA defines source as "any building, structure, facility, or installation which emits or may emit an air pollutant."[51] Courts have interpreted "source" narrowly and reversed EPA attempts to implement standards of performance or complete BSER analyses under Section 111 at a broader level than individual stationary sources.[52]

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[47] *Clean Air Council v. Pruitt*, 862 F.3d 1, 8-9 (D.C. Cir. 2017).
[48] *Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117, 2125 (2016).
[49] *See* 80 Fed. Reg. at 64,720.
[50] 42 U.S.C. § 7411(d)(1).
[51] *Id.* at § 7411(a).
[52] *See Asarco v. EPA*, 578 F.2d 319, 326-27 (D.C. Cir. 1978) ("The regulations plainly indicate that EPA has attempted to change the basic unit to which NSPSs apply from a single building, structure, facility, or installation—the unit prescribed by statute – to a combination of such units. The agency has no discretion to rewrite the statute in this fashion."); *Alabama Power Co. v. Costle*, 636 F.2d 323, 397 (D.C. Cir. 1979) (holding that the term "source" in CAA § 111(a)(3) is of "limited scope" and that "EPA cannot treat contiguous and commonly owned units as a single source unless they fit within the four permissible statutory terms" of building, structure, facility, or installation).

EPA's proposal correctly recognizes that emission guidelines must be established for each class or category of existing stationary source and not on an aggregated basis for the entire electricity generating sector, because the latter would unlawfully include facilities that are not stationary sources. Section 111 could not be clearer: performance standards apply to sources, not owners and operators of sources that might take actions beyond the source itself. Under Section 111(d), a State-established performance standard may be set for an existing source that would be regulated under Section 111(b) "if such existing *source* were a new *source*."[53] State plans must "apply[] a standard of performance to *any particular source*."[54] And EPA's role is to establish a "procedure" for States to submit plans "establish[ing] standards of performance *for any existing source*."[55]

Similarly, the statute expressly contemplates adjustments to a standard of performance as it applies to individual sources in varying conditions. States are directed to take into consideration "the remaining useful life of the existing *source*" when "applying a standard of performance" to "*any particular source*."[56] If EPA promulgates a federal plan in lieu of an unsatisfactory State plan, EPA "shall take into consideration … [the] remaining useful lives of the *sources* in the category of *sources* to which [the applicable] standard applies."[57]

Finally, EPA cannot regulate existing sources under Section 111(d) unless the Agency first regulates under Section 111(b), and Congress likewise made individual "sources" the focus of new source regulation under that section. To commence Section 111(b) regulation, Congress requires EPA first to list categories of "stationary *sources*" to be regulated.[58] EPA then sets standards for new "*sources* within such [listed] category."[59] Once again, for all of these Section 111 provisions, "source" is defined as an individual physical "building, structure, facility, or installation."[60] It is not defined to include the "owner or operator" of the "building, structure, facility, or installation."

Indeed, Section 111 makes this distinction explicit. Congress differentiated the term "owner or operator" from the term "source" by giving the former a distinct definition: "any person who owns, leases, operates, controls, or supervises a stationary source."[61] If Congress had intended to include a facility's owner or operator within the term "source," it would not have separately defined those terms. Section 111 further states that it is unlawful "for any owner or operator of any new source to operate such source in violation of any standard of performance applicable to such source."[62] In fact, Congress had to adopt distinct definitions of "source" and "owner or operator" as well as a specific provision to hold an "owner or operator" of a new source liable

[53] *Id.* at 64,911 *see also id.* at 64,745-47 ("generation shifts").
[54] CAA § 111(d)(1) (emphases added).
[55] *Id.* (emphasis added).
[56] *Id.* (emphasis added).
[57] *Id.* § 111(d)(2) (emphases added).
[58] *Id.* § 111(b)(1)(A) (emphasis added).
[59] *Id*. § 111(b)(1)(B) (emphasis added); see also id. § 111(a)(2) (defining the term "new source" and discussing standards of performance "which will be applicable to such source").
[60] *Id*. § 111(a)(3).
[61] *Id.* § 111(a)(5).
[62] *Id.* § 111(e).

precisely because, contrary to the CPP's central assumption, the owner or operator of a source is legally distinct from the "source" itself.[63]

ii. EPA's Proposed New BSER Determination Is Consistent with the CAA's Legislative History, Intent, and Structure (C-17)

In the proposal, EPA correctly notes that nothing in the statutory text or its legislative history suggests that Section 111 standards may be based on anything other than a physical or operational change to the stationary source itself.[64] Even if the word "system" could be read more broadly out of context, its meaning for purposes of Section 111 should be "clarified by the remainder of the statutory scheme … because only one of the permissible meanings produces a substantive effect that is compatible with the rest of the law."[65] Moreover, an agency interpretation that is inconsistent with the design and structure of the statute as a whole does not merit deference.[66]

Key regulatory terms such as "standard of performance" or "best system of emission reduction" must be interpreted similarly within the interrelated provisions of Section 111, absent clear statutory language to the contrary. After the 1990 CAA Amendments, Congress applied the same statutory definition of "source" in Section 111(a)(1) to new sources under Section 111(b) and to existing sources under Section 111(d). Regulating new sources under Section 111(b) is a necessary predicate to regulating existing sources from the same source category under Section 111(d).[67] Regulations established for new sources under Section 111(b) are technology-based and source-specific.[68] Nothing in the text of Section 111(d) or the legislative history to this provision indicates that Congress intended a different scope for either new or existing sources. In fact, Section 111(d) complements and is informed by the standards of performance and BSER analysis applied under Section 111(b).

The CPP departed from this well-established framework by creating an overly expansive interpretation of "system of emission reduction" that looked beyond the individual source and even beyond sources of emissions. Because Sections 111(b) and 111(d) operate in tandem, the source-specific interpretation of Section 111(a)(1) applies equally to both provisions.

The outside-the-fence-line approach of the CPP was also incompatible with other provisions of the CAA, including the Prevention of Significant Deterioration ("PSD") program. In the PSD program, emissions from required best available control technology ("BACT") cannot exceed the level set by standards of performance under Section 111.[69] Because BACT encompasses "all

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[63] *See Transbrasil S.A. Linhas Aereas v. Dep't of Transp*., 791 F.2d 202, 205 (D.C. Cir. 1986) ("[W]here different terms are used in a single piece of legislation, the court must presume that Congress intended the terms to have different meanings.") (internal quotation marks and citation omitted).

[64] See III.C in 83 Fed. Reg. at 44,752.

[65] *United Sav. Ass'n of Tex. v. Timbers of Inwood Forest Associates, Ltd*., 484 U.S. 365, 370 (1988).

[66] *UARG v. EPA*, 134 S.Ct. 2427, 2442 (2014).

[67] *See* 42 U.S.C. § 7411 (EPA can only set emission guidelines applicable to an existing source "to which a standard of performance would apply if such existing source were a new source").

[68] *See* 40 Fed. Reg. 53,340, 53,341-43 (Nov. 17, 1975).

[69] 42 U.S.C. § 7479(3) ("In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emission allowed by any applicable standard of performance established pursuant to Section 7411 … of this title.").

‘available’ control options … that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation,”[70] BACT applies to the source itself (on a unit-specific or facility-wide basis) but does not include control measures that are outside-the-fence-line and cannot be applied to a particular emissions unit at the facility. Because Congress chose to make standards of performance under Section 111 the “floor” for BACT determinations, it is consistent with Congress’s intended framework for the BSER analyses used to develop those same performance standards to be source-specific, and not exceed beyond the boundaries of the source. As EPA’s proposal recognizes, to allow otherwise would mean that an existing source triggering PSD permitting obligations could be obligated to apply as BACT for an emissions limit that cannot be met by control technology available to the facility.

In stark contrast to the CPP, EPA’s present proposal acknowledges the absence of statutory authority to expand the Agency’s regulatory reach beyond the fence line of stationary sources. API concurs with EPA’s proposed approach because Congress must “speak clearly” before an agency invokes “an unheralded power to regulate a significant portion of the American economy,”[71] in the manner of the CPP. As EPA now recognizes, when Congress has envisioned a broad, non-source specific regulatory program such as a cap-and-trade program, it has expressly established such a program.[72]

Clear congressional authorization is further required here because the CPP raises serious federalism concerns. It is a “well-established principle that it is incumbent upon the federal courts to be certain of Congress’ intent before finding that federal law overrides the usual constitutional balance of federal and state powers.”[73] “This principle applies when Congress ‘intends to pre-empt the historic powers of the States’ or when it legislates in ‘traditionally sensitive areas’ that ‘affec[t] the federal balance.’”[74]

As the D.C. Circuit has said, “[f]ederal law may not be interpreted to reach” areas traditionally subject to State regulation “unless the language of the federal law compels the intrusion” with “unmistakably clear … language.”[75] This “plain statement rule is nothing more than an acknowledgment that the States retain substantial sovereign powers under our constitutional scheme, powers with which Congress does not readily interfere.”[76] Where “[t]he states have regulated [a sector] throughout the history of the country … it is not reasonable for an agency to decide that Congress has chosen” to entrust regulation of that sector to a federal agency.[77]

“[T]he regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States,”[78] which the Supreme Court has specifically recognized should

[70] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* at 24 (Mar. 2011).
[71] *UARG v. EPA*, 134 S.Ct. at 2444 (internal citation omitted).
[72] *See* 42 U.S.C. § 7651-7651o (establishing cap-and-trade program); 42 U.S.C. § 7410(a)(2)(A) (authorizing use of “marketable permits”).
[73] B*ond*, 134 S. Ct. at 2089 (internal quotation marks omitted).
[74] *Raygor v. Regents of Univ. of Minn.*, 534 U.S. 533, 543 (2002); see also Gregory, 501 U.S. at 460-61.
[75] *Am. Bar Ass’n*, 430 F.3d at 471-72 (internal quotation marks omitted).
[76] *Am. Bar Ass’n* at 472.
[77] *Am. Bar Ass’n* at 472.
[78] *Ark. Elec. Coop. Corp.*, 461 U.S. at 377.

not be "superseded" "unless that was the clear and manifest purpose of Congress."[79] Particularly relevant here, the "[n]eed for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States"—indeed, the "franchise to operate a public utility … is a special privilege which … may be granted or withheld at the pleasure of the State."[80]

EPA's authority to "reach into areas of State sovereignty" like this exists only where Congress has drafted statutory language that is "unmistakably clear."[81] In light of these statutory constraints and jurisprudential admonitions, the Agency has herein appropriately recognized the limits of EPA's statutory authority and taken a necessary step toward restraining its BSER determination. API therefore supports EPA's proposed determination that BSER will be limited to measures that can be applied at an affected source.[82]

iii. The Proposal Re-Aligns BSER with Historical Practice and EPA Precedent (C-17)

EPA's proposed rule also best reflects the Agency's historical interpretation of "system of emission reduction." The proposal correctly observes that previous rules under Section 111 limit BSER to physical or operational changes at the source itself. The 1975 preamble to the implementing regulations for Section 111(d)[83] emphasized that the technology-based emission guidelines from BSER analysis must utilize pollution control technologies that, from a physical and economic perspective, can reasonably be installed at existing facilities.[84]

Since 1975, with the unique exception of the CPP, all of EPA's Section 111(d) rules[85] have consistently applied technology-based, source-specific BSER analyses. For example:

- For sulfuric acid production units, EPA established emission guidelines for sulfuric acid mist based on the emission reductions achievable by installing fiber mist eliminators.[86]
- For phosphate fertilizer plants, EPA established emission guidelines after concluding that retrofitting existing sources with spray-crossflow packed bed scrubbers is the BSER.[87]

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[79] *PG&E*, 461 U.S. at 206 (internal quotation marks omitted).
[80] *Id.* at 205 (internal quotation marks omitted); *see also Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).
[81] *Will v. Mich. Dep't of State Police*, 491 U.S. 58, 65 (1989); *Gregory v. Ashcroft*, 501 U.S. 452, 460 (1991); *City of Abilene v. FCC*, 164 F.3d 49, 52 (1999).
[82] Unless otherwise indicated, API takes no position on the specific candidate technologies identified in the BSER analysis.
[83] *See* 40 Fed. Reg. at 53,542-44.
[84] *Id.* at 53,344 ("physical limitations may make installation of particular control systems impossible or unreasonably expensive"); *id.* at 53,341 ("the degree of control reflected in EPA's emission guidelines will take into account the costs of retrofitting existing sources").
[85] Excluding rules for solid waste incineration units issued under both Sections 111(d) and 129, where a more stringent "maximum achievable control technology" standard applies that is not relevant to BSER. *See* 42 U.S.C. §§ 7429(a)(2) and (b)(1); 65 Fed. Reg. 75,338, 75,339 (Dec. 1, 2000).
[86] 41 Fed. Reg. 48,706, 48,706 (Nov. 4, 1976).
[87] 42 Fed. Reg. 12,022, 12,022 (Mar. 1, 1977).

- For kraft pulp mills, EPA set each total reduced sulfur emission guideline on pollution control technology that could be implemented by the sources directly.[88] Because no pollution control techniques were both cost effective and able to be demonstrated on an existing source, EPA declined to set emission guidelines for brown stock washer systems and black liquor oxidation systems.[89]

- For primary aluminum plants, EPA set fluoride emission guidelines based on "average fluoride control efficiencies expected from the application of certain recommended control technologies that are applied as new retrofits to existing plants."[90]

- For municipal solid waste landfills, EPA set methane and non-methane organic compound emission guidelines based on the emission reductions achievable through the installation of a flare that would combust emitted gases.[91]

The long history of Agency rulemaking activity in multiple industrial sectors reinforces the basis for EPA's view that Section 111(d) requires BSER analysis and emission guidelines to rely solely on systems for emission reduction that can be implemented on-site at each regulated source. Because EPA's present proposal reflects this prior practice and faithfully adheres to the text, structure, and legislative history of the CAA, API supports the Agency's proposed BSER analysis.

3. <u>States Should Consider Natural Gas Co-Firing as a Technologically Feasible and Cost-Effective Compliance Option (C-5, C-15)</u>

API supports EPA's proposal to allow States to consider natural gas co-firing as a compliance option.[92] Natural gas co-firing has a longstanding and important role in coal-fired power-production, and the benefits of natural gas co-firing go well beyond the reduction of GHG emissions.

Natural gas co-firing is necessary for the efficient operation of many coal-fired utilities by aiding in coal combustion during start-up and to maintain temperature in units during stand-by periods. In addition to operational benefits, many coal-fired utilities co-fire natural gas to aid in the control of nitrogen oxides ("NO_x") and as a means of reducing CO_2 emissions. EPA's proposal recognizes these measurable and verifiable environmental benefits.[93] And importantly, consistent with the framework EPA is proposing, natural gas co-firing is a control that can be applied at the source itself. Accordingly, at a minimum EPA should expressly allow States to consider the co-firing of natural gas in coal units to be a compliance option in State plans.

It is in the interest of States and power grid operators to have clean and reliable fuel for power generation. Abundant and affordable natural gas has been a key driver of reliability in power generation. EPA should allow and encourage States to act in the best interest of electricity consumers by choosing the least expensive and most efficient compliance solutions. Where

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[88] EPA, *Kraft Pulping: Control of TRS Emissions from Existing Mills* at 10-4 (Mar. 1979).
[89] *Id*. at 10-12.
[90] 45 Fed. Reg. 26,294, 26,294 (Apr. 17, 1980).
[91] 61 Fed. Reg. 9,905, 9,907 (Mar. 12, 1996).
[92] See 83 Fed. Reg. at 44,762.
[93] See 83 Fed. Reg. at 44,762.

optional compliance programs, such as trading or credit programs, are envisioned in State plans, the lower emissions profile of natural gas should be given the appropriate credit for the role it plays in reducing emissions.

API recognizes, however, that EPA considers natural gas co-firing as potentially impermissibly "redefining" coal sources. As such, we are not herein requesting that the Agency reconsider its proposed decision to refrain from listing natural gas co-firing as a candidate technology. While API is not asking EPA to reconsider this decision, we would like EPA to reevaluate some of the rationales it employed when making this decision.

For instance, EPA suggests that natural gas co-firing should be disfavored because it diverts natural gas from more efficient NGCC units in order to achieve more modest emission improvements in less efficient coal-fired units.[94] While API agrees that NGCC units are far more efficient than coal-fired units (even with natural gas co-firing), we do not agree with the Agency's suggestion that co-firing natural gas in coal units precludes NGCC use or expansion. The implication of scarcity underlying this concern is simply baseless. Natural gas is a reliably abundant source of energy in the United States.[95]

EPA similarly argues against natural gas co-firing as a candidate technology because "unlike coal, natural gas cannot be stored in quantities sufficient for sustained utilization on site" and because even those facilities currently co-firing natural gas "may not be able to greatly increase purchase volumes with existing infrastructure."[96] Here again, the Agency's stated justification erroneously relies on baseless (and un-cited) surmise about natural gas abundance and reliability. The United States has around 2,500 trillion cubic feet (Tcf) of technically recoverable natural gas resources, and this number increases every year.[97] It is similarly inaccurate for EPA to suggest that the need for more natural gas pipeline infrastructure makes natural gas co-firing a compliance option available in only a few select regions. While more natural gas pipeline infrastructure is indeed necessary, it is not credible to suggest that natural gas-based compliance options are anything less than widespread and widely available. In 2017, natural gas was actually the largest source (about 32%) of U.S. electricity generation.[98] The U.S. has nearly 1,800 natural gas-powered electricity plants in nearly every State. Natural gas-fired facilities represent over 30% of plants in 23 States, and over 50% in 10 more States.[99]

4. Recommended BSER for Natural Gas Combined Cycle Units (CR-5, C-11, C-15)

EPA is proposing to exclude natural gas-fired EGUs from the "affected facilities" that will be subject to regulation upon finalization of the Proposed ACE Rule.[100] As such, API believes it premature to provide detailed comment on systems of emission reduction that might be identified

[94] See 83 Fed. Reg. at 44,762.

[95] https://www.api.org/oil-and-natural-gas/wells-to-consumer/exploration-and-production/natural-gas/natural-gas-americas-clean-energy

[96] See 83 Fed. Reg. at 44,762.

[97] https://www.eia.gov/tools/faqs/faq.php?id=58&t=8

[98] https://www.eia.gov/energyexplained/index.php?page=electricity_in_the_united_states

[99] https://www.washingtonpost.com/graphics/national/power-plants/?noredirect=on&utm_term=.c4c3478dea44

[100] See 83 Fed. Reg. at 44,754.

in the BSER analysis in a hypothetical future inclusion of these types of EGUs. As an initial matter, however, API concurs with the Agency's conclusion that available emission reductions at natural gas-fired stationary combustion turbines "would likely be expensive or would likely provide only small overall reductions . . ."[101]

Indeed, natural gas-fired stationary combustion turbines are already highly efficient. Electricity generation in these units is the single biggest factor in steady reduction of CO_2 emissions in the power sector.[102] In fact, EPA's own analysis, as well as analysis by EIA and others, shows that these trends have already well outpaced the projections that went into the CPP for many States.[103] Given the pace and significance of these market-based reductions in GHG emissions, there is no basis to assume that EPA would consider expanding the proposed "affected facilities" to include natural gas-fired EGUs. It is even more speculative to identify the systems of emission reduction that could be demonstrated for a category of EGUs that is expanding so rapidly and have driven down power costs and CO_2 emission so profoundly.

In the event that EPA decides to undertake a rulemaking to determine BSER for natural gas-fired stationary combustion turbines, however, API believes that the Agency's approach in the Proposed ACE Rule provides a reasonable and legally defensible approach. EPA should retain this sound, textually-based, and historically consistent interpretation of Section 111(d) as being limited to emission reduction that can be applied to or at an emissions source, thereby excluding actions implemented at other locations that are not the emissions source. The Agency should look to 111(b). Standards under 111(d) cannot be more stringent than the 111(b) limits of 1000 lb CO_2/MWh. The Agency should also continue to fully consider the costs of reductions and other non-air quality and energy impacts. If EPA determines that natural gas-fired stationary combustion turbines are "affected facilities," the Agency should continue to exclude both industrial CHP units and natural gas-fired peaking units in order to encourage the GHG emission reduction and contribution to electricity grid reliability afforded by both of them.

EPA should also continue to grant States, as Section 111(d) requires, the flexibility provided under Section 111(d) and their respective State laws to set standards of performance based on the systems or controls that apply at or to the particular circumstances of the EGUs in their State. EPA should also continue to encourage States to allow sources to meet those standards in the most cost-effective manner using any means of GHG emission reduction.

i. Carbon Capture and Storage (C-12, C-15)

In the CPP, EPA determined that use of full or partial carbon capture and storage ("CCS") technology should not be part of the BSER for existing EGUs because it would be more expensive than the measures determined to be part of BSER, particularly if applied broadly to the overall source category.[104] API supported this determination. In the Proposed ACE Rule, EPA acknowledges that some companies may be interested in using CCS as a compliance method.[105]

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[101] 83 Fed. Reg. at 44,761.
[102] See 83 Fed. Reg. at 44,750-51.
[103] See 83 Fed. Reg. at 44,754.
[104] See 80 Fed. Reg. at 64,756.
[105] See 83 Fed. Reg. at 44,764.

API supports the development of CCS retrofits at both existing and new sources where operators determine that CCS retrofits make economic and business sense. With respect to the application of CCS, "affected EGUs may utilize retrofit CCS technology to reduce reported CO_2 stack emissions."[106]

We also note that EPA concluded that CCS technology retrofits would not be classified as modified or reconstructed units. Specifically, EPA stated in the CPP that "addition of retrofit CCS technology should not trigger Section 111(b) applicability for modified or reconstructed sources. Pollution control projects do not trigger NSPS modifications, and addition of CCS technology does not count toward the capital costs of reconstruction for NSPS."[107] API continues to support this approach.

5. Averaging and Trading (C-15, C-28 – C-42)

API supports EPA's proposal to allow states to incorporate, as a part of their plan, emissions averaging among EGUs across a single facility.[108] We do not agree, however, that the proposed allowance for intra-facility averaging should be limited to coal-fired EGUs. EPA's approach to setting emission guidelines should recognize the States' authority under Section 111(d) to set their own performance standards and should encourage States to recognize the benefits of using natural gas as a GHG reduction strategy to meet each individual EGU's emission target.

As discussed throughout these comments, a large and growing proportion of electricity is produced using natural gas, and this increased use of cleaner-burning natural gas has played a major role in reducing CO_2 emissions to the lowest levels in 25 years. These trends are likely to be durable as the United States continues to reduce GHG emissions through market-driven forces and industry innovation. And EPA, consistent with the flexibility the Agency is extending States elsewhere in this proposal, should allow States to adopt standards that reflect these market forces and to act in the best interest of electricity consumers by choosing the least expensive and most efficient compliance solutions. API therefore recommends that EPA provide States authority under Section 111(d) to adopt standards that allow fuel intra-facility averaging that is fuel neutral, and not limited to coal-fired EGUs.

Additionally, while API concurs with EPA that Section 111(d) should not be used to regulate the aggregate emissions of an industrial sector as a whole, we do not believe that the source-specific focus of Section 111(d) should altogether preclude States from adopting in State plans optional compliance programs that allow for trading between sources or other credit programs. As EPA has repeatedly acknowledged in this proposal, States should have broad flexibility to design their compliance programs and develop their State plans. EPA should not then deprive States of the discretion to utilize trading between sources or other credit programs if the States determine those programs will achieve compliance in the least expensive and most efficient manner.

Of course, environmental regulations affecting power plants also need to consider and minimize the impact on grid reliability, and should be developed and implemented in consultation with grid

[106] See 80 Fed. Reg. at 64,883.
[107] *Id.* at fn 883.
[108] 83 Fed. Reg. at 44,767.

operators and FERC. With the exception of grid reliability considerations within the purview of FERC, however, EPA should adopt a genuinely fuel neutral approach that allow States to account for the lower emissions profile of natural gas and to give appropriate credit for the role it plays in reducing emissions.

c. <u>Proposed Revisions to Emission Guideline Implementing Regulations (C-42 though C-58)</u>

One of the central features of Section 111(d) is the flexibility it affords States to provide reasonable standards of performance for specific facilities or groups of facilities based on their own unique attributes. While it may be practicable under some circumstances to establish uniform standards on new sources based on the fact that the control technology needed to achieve those standards can be incorporated into the facilities at the initial design phase, the same cannot be said for existing sources. Existing sources that were not constructed with new pollution control technologies in mind are typically far less homogenous, and are constrained by past decisions regarding site layout. As a result, certain pollution control technologies may not be technically feasible, and others may prove less effective than they would under optimal design conditions. Finally, in some cases, the cost of certain emission control technologies may be unreasonable due to the source's limited remaining useful life.

Congress, in enacting Section 111(d), recognized these challenges and gave States additional flexibility to establish standards of performance for existing sources. Specifically, Congress authorized States "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[109] While Congress did not specify the "other factors" that States could consider, EPA has previously determined that these factors include, but are not limited to, costs associated with plant age, location, basic process design or the physical inability of installing certain control technology.[110] Further, as EPA has recognized, States can evaluate the viability of control technologies on a case-by-case basis for individual facilities or classes of facilities.[111] This inherent flexibility in the Section 111(d) program allows States to strike an appropriate balance between emission reductions and the economic interests of regulated facilities, their investors, and their customers by adjusting—as appropriate—generally applicable standards of performance to account for source-specific circumstances.

In order to effectuate the Agency's role under Section 111(d)(1), EPA first promulgated implementing regulations in 1975 to provide a framework for subsequent EPA rules and State plans under section 111(d).[112] The implementing regulations have not been significantly revised since 1975 and therefore no longer represent a current interpretation of Section 111(d), which was amended by Congress in 1977. The implementing regulations also no longer reflect Section 110 as amended by Congress in 1990. Accordingly, API supports EPA's proposal to promulgate new implementing regulations that are in accordance with the CAA in its current form.

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[109] 42 U.S.C. § 7411(d)(1)(B).
[110] 40 C.F.R. § 60.24(f).
[111] *Id.*
[112] See 40 CFR part 60, subpart B (hereafter referred to as the "implementing regulations").

As we noted with respect to EPA's proposed BSER analysis (supra), EPA possesses ample authority to revisit its approach to implementing Section 111(d). Indeed, EPA's obligation to ensure that its regulations reasonably interpret the Agency's governing statutes suggests that EPA's proposed reconsideration of the 1975 impending regulations for Section 111(d) is, in fact, mandated.

Regardless of whether this aspect of the proposal is mandatory or permissive, API believes that these proposed changes to 40 CFR part 60, subpart B are an important step toward more fully recognizing the express grant of authority provided by Section 111(d) to States to design their own State plans and (if States deem appropriate) to develop unit-specific standards of performance taking into account State-specific circumstances or other unique opportunities. State and local administrators have the most knowledge regarding the specific mix of GHG emission reduction options that are technically and economically viable for source within their borders, and understand how these control options may affect uniquely local concerns.

In addition to expressing our broad support for EPA's proposed review of the Agency's Section 111(d) implementing regulations, API provides the following specific responses and recommendations.

1. <u>Electronic Submittal of State Plans (C-44, C-45)</u>

API agrees that allowing States to submit information electronically is likely less burdensome, and takes no position on whether EPA should provide this as the sole means of submission. Equally important to submission requirements, however, the implementing provisions should require public access to all of the submitted documents in an electronic form. This can be accomplished by establishing a docket for the materials in regulations.gov, or otherwise posting these materials on EPA's or the State's website.

2. <u>Applicability and Timing of Existing and Proposed New Implementing Regulations (C-47, C-48, C-49)</u>

EPA proposes that the criteria for establishing emissions guidelines and approving State plans in the new regulation would apply only for evaluating State plans under newly issued emissions guidelines; but that the timing for States to submit a State plan and for EPA to approve a State plan would apply to all State plans including those submitted or approved to comply with existing emissions guidelines. If this is the correct interpretation of EPA's proposal, API does not object to the proposed applicability provisions (assuming EPA makes appropriate changes to the new regulations) but notes that the introductory language in §60.20a does not appear to achieve this goal, as it would apply the provisions to States only to emissions guidelines published after promulgation.

3. <u>EPA's Proposed Inclusion of a Provision that Expressly Allows for Any Emission Guideline to Supersede the Applicability of the Implementing Regulations (C-51)</u>

API supports inclusion of this provision.

4. Proposed Deadlines for State Plan Submissions, EPA Review of State Plans, and Federal Implementation Plans (C-13, C-52, C-53, C-54, C-55)

EPA's proposed changes to its existing regulatory deadlines under Section 111(d) also reflect the important role Congress preserved for State agencies. The existing implementing regulations at 40 CFR 60.23(a)(1) require State plans to be submitted to EPA within nine months after publication of a final emission guideline, unless otherwise specified in an emission guideline. These tight deadlines may be achievable where the State can exercise little discretion and where the role of a State is effectively limited to adopting EPA's guidelines into its State plan or risking the imposition of a federal plan. Where States have the discretion and flexibility to develop their own plans, however, the existing deadlines are clearly insufficient. Developing State plans that include unit-specific standards, and implementation and enforcement measures for such standards is necessarily time-consuming. And in order to genuinely preserve State discretion to undertake such processes, EPA is appropriately proposing to provide States the time they need to exercise this discretion.

API also supports EPA's alignment of the plan submission procedures with the Section 110 timeframes for SIP submissions and approvals, because these timeframes better align with the length of time necessary to process regulations at the State and federal level. Moreover, API agrees that EPA should retain discretion to designate alternative time frames, as currently proposed in §60.23a(a)(1), because Congress provided EPA flexibility to establish procedures similar to, but not necessarily, identical to the Section 110 submission process.

5. Completeness Criteria

API supports EPA's proposal to provide States with guidance on the minimum elements necessary for EPA to act on a State submission.[113] We believe that providing these elements can help States navigate the State plan submission process and comply with applicable deadlines. Because EPA is proposing these changes to help increase the efficiency of State responses, API urges the Agency to take additional steps to ensure that the proposed completeness criteria cannot be construed as new or additional criteria, requirements, or obligations.

6. Proposed Definition of "Standard of Performance" (C-56)

API supports EPA's proposed definition of "standard of performance."[114] In particular, we support the Agency's proposal to also incorporate into a definition of standard of performance the Section 111(h) allowance for design, equipment, work practice, or operational standards as alternative standards of performance under the statutorily prescribed circumstances.

Currently, the existing implementing regulations allow for State plans to prescribe equipment specifications when emission rates are "clearly impracticable" as determined by EPA. Section 111(h)(1), by contrast, allows for alternative standards, such as equipment standards, to be promulgated when standards of performance are "not feasible to prescribe or enforce," as those

[113] See 83 Fed. Reg. at 44,772.
[114] See 83 Fed. Reg. at 44,772-3.

terms are defined under Section 111(h)(2). API believes that removal of the phrase "not feasible to prescribe or enforce" as the condition for the establishment of alternative standards can help preserve State discretion and flexibility as Congress intended when it drafted Section 111(d).

7. State Authority to Establish Standards of Performance and/or Seek Variances Based on "Remaining Useful Life" and Other Factors (C-22, C-23, C-57, C-58)

API agrees that the existing variance provisions at §60.24(f) do not appropriately carry out the provisions of Section 111(d)(1)(B)[115] and believes that §60.24(f) should be structured so that the Agency can freely use its variance authority to increase State flexibility and discretion under the Section 111(d) program. We believe it is important to point out, however, that States do not, and should not, need variances to design and implement compliance options that differ from the BSER guidance provided by EPA.

Section 111(d)(1)(B) already makes it clear that the Administrator "shall" allow the State to consider "among other factors, the remaining useful life of the existing sources to which such standard applies." Although Congress delegated to EPA the responsibility of establishing a procedure for approving State plans, nothing in the language of Section 111(d) indicates that Congress intended EPA to substitute its judgement for that of the State.

Although API supports EPA's proposed expansion of the factors under which EPA may grant a variance, even the expanded list of exemptions is too narrow. Section 111(d)(1)(B) provides States broad authority to consider "other factors" in their State plans. At a minimum, EPA should clarify that the variance provisions in §60.24(f) cannot, and should not, be construed to narrow or diminish State discretion and flexibility under Section 111(d)(1)(B).

8. Changes to the Definition of "Emission Guideline"

While EPA has not provided a regulatory definition of an "emission guideline," prior Agency interpretations suggest that an "emission guideline" would be a guideline provided by EPA that presumptively reflects the degree of emission limitation achievable by the BSER. Nothing in Section 111(a)(1) or Section 111(d), however, compels EPA to provide a presumptive emission standard that reflects the degree of emission limitation achievable by application of the BSER, nor do these statutory provisions suggest that States are compelled to adopt whatever standards EPA recommends as part of its emission guideline. As such, EPA's proposed re-definition of "emission guideline" as "a final guideline document published under § 60.22a(a)[116], which includes information on the degree of emission reduction achievable through the application of [BSER]," reflects the important distinction between dictating precise controls to States and providing States the tools they need to develop their own protective approaches under Section 111(d).

[115] See 83 Fed. Reg. at 44,773.
[116] See 83 Fed. Reg. at 44,771.

d. <u>Proposed Revisions to the New Source Review Program (C-61, C-62, C-65, C-68)</u>

EPA's proposal appropriately recognizes that the uncertainty and complexity created by the NSR program remains a significant obstacle to efficiency improvements. This uncertainty and complexity, however, is not limited to the utility industry. NSR rules similarly discourage other industries, like the refining and petrochemical manufacturing industry, from exercising the discretion to undertake energy efficiency improvement projects. The major NSR permitting process is time consuming and resource intensive, and—including pre-permit application work—can take three years or longer. The uncertainty of permit timing can hinder investment decisions as much as the actual permit schedule delays. As such, NSR applicability determinations and the threat of triggering time-consuming and costly NSR permitting requirements have caused refiners and other manufacturers to forego plant changes that could improve the efficiency, reliability, and capacity utilization of their units.

For these reasons, API has for many years, and in multiple contexts, supported efforts to reform NSR. For these same reasons, API believes that EPA should take this important opportunity to move forward with guidance and regulatory reforms to NSR applicability and permitting that would apply broadly to the utility and manufacturing sectors alike, as well as address the types of circumstances where efficiency improvements would or would not trigger NSR. As a continuation of EPA's NSR reform efforts, there are several ways in which the agency could minimize or eliminate major NSR's disincentives for all industrial sources undertaking energy-efficiency projects, in lieu of adding an upfront hourly emissions test to the NSR regulations.

EPA could issue additional guidance that extends the routine maintenance, repair and replacement exemption under NSR and NSPS to the replacement of equipment that is more energy-efficient, as long as it does not result in a change to the equipment's physical design capacity or emissions considered under any previous air quality analysis. This guidance would incentivize companies to replace equipment with current technology during maintenance activities, rather than "in-kind" equipment so that NSR permitting is not triggered.

Another way EPA could promote energy-efficiency projects is to issue guidance to clarify the actual-to-projected-actual test regarding the calculation methodologies for taking into account demand growth of the facility and what it was capable of accommodating before implementing the project at issue. This guidance would be an extension of the memorandum Administrator Pruitt issued in December 2017, and clarify that any increase in emissions of non-GHG pollutants that could have been accommodated by the facility prior to the project are unrelated to the project, if the rate of emissions per unit of production is projected to be less after the project than before it, and the project does not increase the design capacity of the facility.

EPA could also issue additional guidance on Plantwide Applicability Limit ("PAL") permits that provides greater flexibility for facilities to make heat rate improvements ("HRI") to equipment, such as extending the renewal period to 20 years for evaluating the PAL emission limits against current BACT.

As relevant to EPA's current proposal, API supports the addition of an hourly emissions test within the existing major NSR applicability framework, because such a test would provide a simpler way of prospectively identifying whether a project will result in an emissions increase triggering NSR. By removing regulatory disincentives to efficiency improvements, EPA's proposed hourly emissions test could also improve environmental outcomes and advance energy independence and security goals. Again, however, because the impediments caused by the existing NSR permitting framework are widespread across multiple industries, EPA's proposal to limit its NSR reform effort to EGUs would unnecessarily hamstring the environmental and energy improvements that could be realized through this important reform effort.

While HRI might be the primary measure of efficiency in the utility industry, it is no different than energy efficiency improvements pursued in all other industries. All industries are challenged to improve energy and operational efficiency as a means of controlling costs and achieving voluntary and regulatory initiatives, as well as national policy goals. For instance, Section 106, "Voluntary Commitments to Reduce Industrial Energy Intensity" in the Energy Policy Act of 2005, set a national policy goal to reduce the "energy intensity" of industry—not just EGUs—by reducing "the primary energy consumed for each unit of physical output in an industrial process."[117]

HRI and operational efficiency activities undertaken to improve the safety, reliability, and efficiency of refinery operations do not cause increases in the production and hours of operation of any given facility. Production at any given facility may increase to meet consumer demand; and like EGUs, it is in the nation's interest to assure that this production occurs at more efficient operations.

API believes that finalizing an hourly emissions test for EGUs, as well as petroleum refineries and other industry sectors, would provide a more supportable and legally defensible final rule. While (as discussed below) EPA's legal and regulatory justifications for the proposed hourly emissions test appear sound, EPA's rationale for distinguishing EGUs from petroleum refineries or other industrial sectors is altogether absent. Like EGUs, petroleum refineries are heavily regulated and driven by economic need to operate at maximum operational efficiency. API therefore recommends that EPA expand the proposed NSR "hourly test" to include all industry sectors. API is hopeful that EPA share our view that this proposed change should be just one part of a larger and more comprehensive effort to minimize or eliminate major NSR's disincentives for all industrial sources undertaking energy-efficiency projects.

e. <u>**The Regulatory Impact Analysis for this Action Reflects a Significant Improvement Over the Analysis EPA Conducted for the Clean Power Plan (C-1, C-72, C-73)**</u>

API supports the key elements of EPA's approach to assessing the potential impacts of its proposed rulemaking. We believe the RIA that accompanied EPA's proposal appropriately considered a range of scenarios, explained the bases for EPA's assumptions, disclosed the sources and extent of uncertainty, and presented the data in a clear and focused manner. API was also encouraged to see that the RIA contained analytical improvements recommended by API in several earlier rulemaking efforts, including EPA's recent advanced notice of proposed rulemaking on "Increasing Consistency and Transparency in Considering Costs and Benefits in the Rulemaking

[117] *See* 42 U.S.C. 15811

Process."[118] We discuss many of these improvements below. On a more fundamental level, however, API was pleased to observe the the relationship between the RIA analysis and EPA's proposed approach strongly suggests that EPA used the analysis to guide and improve its decision-making.

In *Michigan v. EPA*, the Supreme Court evaluated whether EPA had properly promulgated the MATS Rule. In particular, the court considered whether the Section 112(n)(1)(A) requirement that the Agency promulgate rules that were "appropriate and necessary" to control power plant emissions mandated consideration of cost. A majority of the Supreme Court concluded that the phrase "appropriate and necessary" did amount to a congressional mandate to consider cost. More importantly, however, the Court found that this congressional mandate was not exclusively embodied in the phrase "appropriate and necessary:"

> Agencies have long treated cost as a centrally relevant factor when deciding whether to regulate. Consideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions. It also reflects the reality that 'too much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems.'[119]

The Supreme Court in *Michigan v. EPA* further held that:

> One would not say that it is even rational, never mind 'appropriate,' to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits. . . . No regulation is 'appropriate' if it does significantly more harm than good.[120]

Moreover, while the dissent in *Michigan v. EPA* disagreed with the majority on the precise point in the rulemaking process that EPA was required to evaluate costs under Section 112(n)(1)(A), the dissenting justices agreed with the majority that agencies must consider costs in all instances unless expressly prohibited:

> Cost is almost always a relevant—and usually, a highly important—factor in regulation. Unless Congress provides otherwise, an agency acts unreasonably in establishing a standard-setting process that ignores economic considerations. At a minimum, that is because such a process would threaten to impose massive costs far in excess of any benefit. And accounting for costs is particularly important in an age of limited resources available to deal with grave environmental problems . . .[121]

[118] 83 Fed. Reg. 27,524 (June 13, 2018).
[119] *Michigan v. EPA*, quoting *Entergy Corp. v. Riverkeeper, Inc.*, 556 U. S. 208, 233 (2009) (BREYER, J., concurring in part and dissenting in part).
[120] *Michigan v. EPA* at 7.
[121] *Michigan v. EPA* at 6-7.

While the phrase "appropriate and necessary" was at issue in *Michigan v. EPA*, both the majority and the minority clearly indicated that EPA's obligation to consider costs in rulemaking was inherent in the Agency's obligation to engage in "reasoned decision-making," and not a function of that precise phrase. Indeed, as then-Judge Kavanaugh noted in dissent in the United States Court of Appeals decision on the MATS Rule that was appealed to the Supreme Court in *Michigan v. EPA*, where the "only statutory discretion is to decide whether it is 'appropriate' to go forward with the regulation ... common sense and sound government practice" warrant consideration of both costs and benefits.[122]

EPA's RIA for the Proposed ACE Rule appropriately analyzes the costs and benefits of the proposed rule based on established and accepted regulatory impact analysis principles and guidance and the significant uncertainties associated with evaluating the potential impacts of future regulatory action by States utilizing the flexibilities created by the Proposed ACE Rule.

Consistent with the requirements of the CAA and OMB guidance, the RIA focuses on claimed forgone *domestic* climate benefits from the Proposed ACE Rule, versus claimed forgone *global* climate benefits.[123] The RIA also follows OMB guidance on the discount rate to be used in determining the forgone benefits of the Proposed ACE Rule by considering both a 3 and 7 percent discount rate.[124]

The RIA also follows OMB guidance when addressing the asserted forgone health co-benefits as ancillary benefits.[125] While the RIA does include an assessment of the co-benefits of reducing $PM_{2.5}$ emissions, EPA presented the data separately and appropriately disclaimed the uncertainty inherent in extrapolating $PM_{2.5}$-related mortality risks below the Lowest Measured Level ("LML").

1. The RIA Properly Focuses EPA's Analysis on Forgone Domestic Climate Benefits

EPA's analysis was properly constructed to weigh domestic costs against domestic benefits. In so doing, EPA was better able to ensure that projected domestic impacts alone justify the costs the Agency is proposing to impose on domestic industries.

In Section 101(b)(1), Congress expressly stated that the statute's purpose is to "protect and enhance the quality of the *Nation's* air resources so as to promote the public health and welfare and the productive capacity of *its population*."[126] By focusing on "the Nation" and "its population," Congress clearly demonstrated that it enacted the CAA to affect domestic air quality. Prior to promulgating the CPP, EPA had in fact agreed with this interpretation—and did so in a climate

[122] *White Stallion Energy Ctr, LLC v. Envtl. Prot. Agency*, No. 12-1100 (D.C. Cir. 2014) (Kavanaugh, J. dissenting).
[123] See RIA, Ch. 4; See also 83 Fed. Reg. at 44,786.
[124] See RIA; See also 83 Fed. Reg. at 44,784.
[125] See RIA, Ch. 4; See also 83 Fed. Reg. at 44,786.
[126] CAA § 101(b)(1) (emphasis added).

change-related rulemaking when EPA issued the Endangerment Finding under Section 202(a) of the CAA.[127] API supports EPA's return to this approach.

2. The RIA Properly Followed OMB Guidance on Discount Rates

EPA evaluated the potential regulatory impacts of the Proposed ACE Rule under four different scenarios (an illustrative "No CPP" scenario and the three additional illustrative policy scenarios that use the existence of the CPP as a baseline condition) using the present value of costs, benefits, and net benefits.[128] These were calculated for the years 2023-2037 from the perspective of 2016, using both a 3% and 7% beginning-of-period discount rate.[129] In addition, the Agency presented the assessment of costs, benefits, and net benefits for specific snapshot years (2025, 2030, and 2035).[130]

The RIA also noted that there remain additional sources of uncertainty that have not been fully characterized and explored due to remaining data limitations in considering alleged intergenerational effects. Citing a 2017 report from the National Academies, EPA found that "additional research and analysis is still needed to develop a methodology for implementing a declining discount rate for claimed intergenerational benefits and to understand the implications of applying these theoretical lessons in practice."

As such, the Agency's approach here appropriately follows the guidance that OMB provided in Circular A-4 by calculating the effect that a lower discount rate would have. Only after considering the needed research and inherent uncertainties, did EPA opt to utilize standard discount rates in its RIA. API supports this approach.

3. The RIA Properly Focused on Targeted Pollutant Benefits

Co-benefits drove the Agency's justification in the RIA for the CPP. In that RIA, EPA noted that reducing CO_2 emissions from the electricity sector would also reduce emissions of SO_2, NO_2, and directly emitted $PM_{2.5}$, which will, in turn, reduce ambient concentrations of $PM_{2.5}$ and ozone.[131] Depending on the discount rate that was applied, these co-benefits were estimated to be as much as one order of magnitude greater than the benefits EPA associated with reducing CO_2 emissions alone. In other words, it was the co-benefits—not CO_2 reductions—that underpinned EPA's assertion that the CPP would produce net benefits.

While OMB Circular A-4 states that cost-benefit "analysis should look beyond the direct benefits and direct costs of your rulemaking and consider any important ancillary benefits and countervailing risks,"[132] EPA's consideration of claimed health co-benefits has too often impaired the Agency's ability to meaningfully evaluate the rationality and necessity of regulating the

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[127] See Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the CAA, 74 Fed. Reg. 66496, 66514 (Dec. 15, 2009) ("[T]he primary focus of the vulnerability, risk, and impact assessment is the United States").
[128] See RIA. Ch. 4; See also 83 Fed. Reg. at 44,784.
[129] See RIA. Ch. 4; See also 83 Fed. Reg. at 44,784.
[130] See RIA. Ch. 4; See also 83 Fed. Reg. at 44,784.
[131] RIA at ES-9.
[132] OMB, Circular A-4, at 26.

pollutant/sources targeted by the rule. Co-benefits no longer play an ancillary role in EPA's justification for new regulations. API believes that when EPA is choosing whether or not to regulate, or the level of regulation based on a cost-benefit analysis, decisions should be made based on the benefits from the primary pollutant being regulated.

EPA's RIA for the Proposed ACE Rule strikes a better balance between the need to focus on the pollutant to be targeted by the regulation (CO_2), while also quantifying the ancillary benefits of reducing non-targeted pollutants (SO_2, NO_x, $PM_{2.5}$). To estimate the climate benefits associated with changes in CO_2 emissions, EPA applied a measure of the domestic social cost of carbon ("SC-CO_2"). To estimate the health co-benefits of other pollutants, EPA monetized the value of the forgone human health benefits among populations exposed to changes in $PM_{2.5}$ and ozone.[133]

The Proposed ACE Rule is expected to alter the emissions of SO_2, and NO_x, emissions, which will in turn affect the level of $PM_{2.5}$ and ozone in the atmosphere. Using photochemical modeling, EPA predicted the change in the annual average $PM_{2.5}$ and summer season ozone across the U.S. for the years 2025, 2030 and 2035. EPA next quantified the human health impacts and economic value of these changes in air quality using the environmental Benefits Mapping and Analysis Program—Community Edition. EPA quantified effects using concentration-response parameters that are consistent with those employed by the Agency in the PM NAAQS and Ozone NAAQS RIAs.[134]

More specifically, the RIA used three separate scenarios, with each scenario assuming the claimed co-benefits would start to accrue at different $PM_{2.5}$ emissions thresholds:

- No threshold: This assumes there is no emissions level at which claimed forgone health co-benefits associated with reduced $PM_{2.5}$ levels cease to accrue;
- Studies-based measurement: This assumes the claimed forgone health co-benefits with $PM_{2.5}$ levels are zero at the LML of certain epidemiological studies (5.8 $\mu g/m^3$ and 8 $\mu g/m^3$); and,
- NAAQS threshold: This assumes the forgone health co-benefits associated with $PM_{2.5}$ levels are zero at the primary annual $PM_{2.5}$ NAAQS (12 $\mu g/m^3$).

As evidenced in the table EPA provided in the RIA and Federal Register Notice, the possible forgone health co-benefits that EPA calculates differ dramatically depending upon which scenario EPA applies to calculate the claimed benefits. Because of the substantial uncertainty inherent in these widely differing calculations, API believes it was appropriate for EPA to give more weight to cost-benefit calculations that focus on the claimed potential risks associated with $PM_{2.5}$ levels above the primary annual $PM_{2.5}$ NAAQS. As EPA stated in the preamble:

> In general, EPA is more confident in the size of the risks estimated from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, EPA is less confident in the risk EPA estimates from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies. Furthermore, when setting

[133] 83 Fed. Reg. at 44,786.
[134] U.S. EPA, 2012; 2015.

> the 2012 PM NAAQS, the Administrator also acknowledged greater uncertainty in specifying the 'magnitude and significance' of PM-related health risks at PM concentrations below the NAAQS. As noted in the preamble to the 2012 PM NAAQS final rule, 'EPA concludes that it is not appropriate to place as much confidence in the magnitude and significance of the associations over the lower percentiles of the distribution in each study as at and around the long-term mean concentration.' In general, we are more confident in the size of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

While API continues to believe that EPA's assumptions may overstate mortality risks from $PM_{2.5}$,[135] focusing on the claimed forgone health co-benefits based on the primary annual $PM_{2.5}$ NAAQS is presumptively a more accurate assessment, since such calculations would be based on a clear numerical regulatory threshold that EPA has already studied and determined "protect[s] the public health" with an adequate margin of safety.[136] By definition, any "better than NAAQS" co-benefits are inherently less certain.

f. <u>Conclusion</u>

API appreciates the opportunity to provide these comments. If you have any questions, please contact me at (202) 682-8340.

Sincerely,

/s/

Howard J. Feldman

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[135] For further discussion, see API's comments on EPA's ANPRM on "Increasing Consistency and Transparency in Considering Costs and Benefits in the Rulemaking Process."

[136] CAA § 109(b)(1).