The Clean Energy Group

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Washington, DC 20460
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Re: National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units

To Whom It May Concern:

The Clean Energy Group appreciates the opportunity to comment on the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units (EGU MACT).

The Clean Energy Group is a coalition of electric utilities and electric generating companies that share a commitment to responsible environmental stewardship. Among the members are some of the largest electric and natural gas utilities, serving over 33 million electric customers and over 35 million natural gas customers. They are also some of the nation's largest generators of electricity, with nearly 213,000 megawatts (MW) of generating capacity throughout the U.S., which represents approximately 20 percent of total U.S. generating capacity.

The EGU MACT provides the business certainty the electric sector needs to move forward with capital investment decisions, and the Clean Energy Group supports finalizing the rule as required by consent decree in November 2011. While we offer specific recommendations below, overall, we believe the proposal is reasonable and consistent with the requirements of the Clean Air Act. We also demonstrate, below, that the electric sector is well-positioned to comply. Further, where individual circumstances warrant, Section 112 of the Clean Air Act provides additional flexibility to accommodate situations where additional time may be necessary to install controls.

Our recommendations on specific revisions to the proposed rule address broad comments applicable to all existing steam electric generating units (EGUs), and then comments specific to existing coal- and oil-fired EGUs, respectively. We appreciate EPA's diligent efforts to complete the rule on the required schedule.

I. Recommendations Applicable to All Existing EGUs (Coal and Oil)

a. Compliance Schedule

The Clean Air Act provides the necessary time to comply with the Utility Toxics Rule, and the electric sector can comply with the Utility Toxics Rule within the timing required by the Clean Air Act without significant impacts to electric system reliability. The express language of the Act is clear regarding the timing to comply, and the industry has long been aware of the Act's compliance schedule. Section 112 of the Clean Air Act requires existing sources to comply with EPA's MACT standards and operating limitations *no later than three years* after the effective date of the standards.[1] However, if there are specific instances where a company needs additional time beyond three years to install controls, despite its best efforts to comply, the Clean Air Act authorizes EPA, or states, to provide the needed time on a case-by-case basis, though any unit receiving additional time should not receive any undue economic gain as a result of any extension.

In December 2000, EPA made a determination that it was appropriate and necessary to regulate HAPs from coal- and oil-fired EGUs. In October 2009, EPA signed a consent decree requiring the Agency to sign a notice of proposed rulemaking outlining its proposed section 112(d) emission standards for coal- and oil-fired EGUs by March 16, 2011, and a notice of final rulemaking by November 16, 2011.

The Clean Energy Group companies agree with the Agency that the statutory deadline of three years will generally be adequate to design, install, and test pollution control systems at existing power plants, as well as obtain permits for the use of add-on controls. We base this conclusion on extensive experience permitting and constructing pollution control systems at fossil generating facilities. In many cases, companies began planning their compliance strategies in advance of the rule's proposal. For example, NextEra Energy began evaluating control technology options at its oil-fired generating units in Florida before the release of the proposed rule. Prior to the release of the Utility MACT proposal, NextEra started the public service commission (PSC) approval process. The PSC approved NextEra's request, allowing NextEra to begin installing electrostatic precipitators (ESPs) based on the proposed Utility Toxics Rule.[2] Similarly, Constellation Energy conducted preliminary engineering studies before the Maryland

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[1] *(3) COMPLIANCE SCHEDULE FOR EXISTING SOURCES.*
(A) After the effective date of any emissions standard, limitation or regulation promulgated under this section and applicable to a source, no person may operate such source in violation of such standard, limitation or regulation except, in the case of an existing source, the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard […].
(B) The Administrator (or a State with a program approved under title V) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) if such additional period is necessary for the installation of controls.[…]
CAA Section 112(i)(3)(A)-(B)

[2] Florida Public Service Commission, Final Order Approving Projected Expenditures And True-Up Amounts For Environmental Cost Recovery Factors For Florida Power & Light Company, Docket No. 100007-E, January 31, 2011 (available at: http://www.floridapsc.com/library/filings/11%5C00735-11%5C00735-11.pdf).

Legislature enacted the Healthy Air Act in 2006. This allowed Constellation to apply for a Certificate of Public Convenience and Necessity for the installation of controls about one month after Maryland finalized the regulations implementing the Healthy Air Act.

However, there may be situations where additional time is required to install the necessary controls (e.g., when a company is required to schedule and coordinate multiple outages at a single facility or when a unit is needed for reliability purposes). The majority of these limited situations can be addressed on a case-by-case basis under section 112(i)(3)(B) of the Clean Air Act, which allows EPA or states to provide up to one additional year for the installation of pollution control technologies. States have provided additional time under this subsection of the Act for other sectors, and we anticipate that states will continue to provide such additional time if needed by electric generators to install controls.

Additionally, if a company demonstrates a need for time beyond four years, EPA has the authority to enter into administrative orders of consent (AOCs) or consent decrees to provide such additional time. EPA has used AOCs and consent decrees in the past to address similar situations.

In these limited cases of extensions beyond three years, it will be important for EPA to ensure that a company uses the additional time to install controls or test the installation of controls and to ensure a unit is only dispatched for reliability purposes so that it does not receive any undue economic gain as a result of an extension.

To ensure companies have a clear understanding of what situations will be eligible for additional time, the Clean Energy Group recommends that EPA prescribe a set of conditions for obtaining an extension. For example, the company must demonstrate a clear need for additional time to install controls despite a company's best effort to comply within the three years. Companies should also have a compliance plan, including contract deadlines, to ensure the time will be used to complete the installation of controls within the additional time provided by EPA or the state.

We recommend that EPA require that each EGU owner submit, within one year after the effective date of the Toxics Rule, a notice as to whether the EGU will be retrofitted or retired. If the unit is to be retrofitted, EGU owners should also be required to submit a compliance plan for the project as a condition of any extension. Under 40 C.F.R §63.6(i)(4)(B), owners are generally required to submit a request no later than 120 days before a compliance date; however, given the long lead times required to retrofit a plant and to plan for any retirements, it is important that EPA require owners to identify which facilities they will upgrade and which they will retire much sooner than 120 days before the end of the three-year compliance period.

Requiring notice of retrofit and retirement plans within a year of the effective date would serve several purposes. First, the requirement would promote confidence in electric reliability by requiring early identification of units that will be retired. While we expect reliability concerns to be unlikely, if there are specific local concerns, such notice would ensure any potential concerns are identified and addressed at an early stage. Second, early identification of planned retrofits would also assist permitting agencies in planning to meet the demand for permit application reviews. Third, the requirement would help ensure that companies know early in the planning process whether or not they are eligible for any extensions for the installation of controls.

We also recommend that EPA establish an expedited permitting program for units that require Title V and/or PSD permit modifications as a precondition of constructing new controls. This would further ensure that there is adequate time to comply.

b. Labor Availability

The Clean Energy Group does not believe that labor availability will constrain the industry's ability to install the necessary controls in the timeframe required by the Clean Air Act. In October 2010, Senator Thomas Carper asked the Institute for Clean Air Companies (ICAC)—the trade association that represents the air pollution control industry—whether labor availability was likely to constrain the industry as it seeks to comply with the Cross-State Air Pollution Rule (a.k.a., Transport Rule) and the EGU MACT Rule. In response, ICAC's Executive Director stated: "[t]hese concerns [about labor availability] and doubts are being raised again; however, based on a history of successes, we are now even more resolute that labor availability will in no way constrain the industry's ability to fully and timely comply with the proposed interstate Transport Rule and upcoming utility MACT rules. Contrary to any concerns or rhetoric pointing to labor shortages, we would hope that efforts that clean the air also put Americans back to work."

ICAC based its conclusion on several factors: (1) the electric power sector has a demonstrated ability to install a large number of complex pollution control systems in a relatively short period of time, while coordinating outage schedules to maintain electric system reliability; (2) the majority of coal plants have already installed advanced pollution control systems; and (3) there are less resource and labor-intensive control technology options that will be used for compliance.

c. Outreach Prior to Compliance Deadline

We commend the Agency for its outreach to stakeholders in advance of the rule proposal, including state Public Utility Commissions (PUCs), Regional Transmission Organizations (RTOs), the National Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), the Edison Electric Institute, as well as the Clean Energy Group and individual member companies, and we encourage EPA to continue this outreach and coordination throughout the development of the rule and after the rule has been finalized.

d. Stack Testing Frequency

In the proposed rule, units not measuring emissions continuously (e.g., using continuous emissions monitoring systems [CEMS] or sorbent traps) must conduct monthly or bi-monthly stack tests to demonstrate compliance. For example, liquid oil-fired EGUs would be required to test for all HAP metals on a monthly basis if they do not have a PM control device installed, or once every two months if they do. Additionally, they would need to test for hydrogen chloride (HCl) and hydrogen fluoride (HF) on a monthly basis because there are no controls currently installed for addressing these pollutants at oil-fired EGUs. Coal-fired EGUs would face similar obligations for pollutants not measured by CEMS or sorbent traps.

The Clean Energy Group has several concerns with the proposed compliance testing requirements. In particular, we believe that the proposed frequency of testing will place a significant cost burden on plant operators. Stack testing can also can be unsafe for testing personnel during harsh weather conditions, particularly the cold winter months. Finally, inflexible testing schedules may induce units to run solely for testing purposes, leading to increased emissions. In addition to company costs and staff time, we assume that, like other rules requiring stack tests, state-level environmental regulators may need to be on site to witness the tests. Given the large number of units affected by the rule and the proposed testing frequency, staff availability could be a significant issue. This could result in delayed compliance testing, testing when the unit would not otherwise run, or not being able to run a unit when it is called.

In an effort to balance these concerns with the need for reliable compliance demonstrations, we recommend that all stack testing requirements should be no more frequent than quarterly under standard operation (i.e., unless boiler operations or characteristics are substantially altered, in which case initial testing should be repeated). Quarterly stack testing in combination with parameter monitoring should be enough to ensure that a unit is operating within the required limits. Quarterly testing would capture seasonal variations in operation while not unnecessarily repeating testing of the same conditions.

In addition, to avoid running a unit simply to conduct a stack test, we recommend that EPA adopt an approach similar to that used in Part 75 for defining an operating quarter and unit operating hour. Specifically, 40 CFR 72.2 defines a “QA operating quarter” as “a calendar quarter in which there are at least 168 unit operating hours (as defined in this section) or, for a common stack or bypass stack, a calendar quarter in which there are at least 168 stack operating hours (as defined in this section).” A unit operating hour would be defined as a clock hour during which a unit combusts any regulated fuel, either for part of the hour or for the entire hour. We are recommending that this definition apply specifically to the regulated fuels under the EGU MACT rule (e.g., coal and liquid oil). By requiring a minimum level of operation to trigger stack testing requirements, this approach would ensure that no unit is run simply for the sake of testing.

e. Low-Emitting Units

The Clean Energy Group supports EPA’s proposal to establish alternative monitoring requirements for low-emitting EGUs (LEE) to reduce the monitoring costs for low-emitting units, but recommends a less burdensome approach for determining continuous compliance and asks that EPA clarify certain aspects of the provisions.

EPA proposes that units with low emissions should be eligible for reduced compliance testing. LEE status requires, with the exception of mercury, emissions less than 50 percent of the applicable emissions limitation. For mercury, LEE status requires emissions that are less than 10 percent of its applicable mercury emissions limit or less than 22.0 pounds per year of mercury. When qualifying for LEE status for mercury based on a unit’s annual emissions (i.e., emissions less than or equal to 22.0 pounds per year), the affected unit must also demonstrate compliance with the applicable emission rate limitation specified in Table 2 to Subpart UUUUU of Part 63.

Table 5 to Subpart UUUUU of Part 63, which details the performance stack testing requirements, includes the requirements for LEE testing; however, it only includes the requirements for mercury testing. The Clean Energy Group requests clarification that LEE status is available to all subcategories and all HAPs, not just mercury from coal units. The discussion of LEE status in §63.10005 and in the preamble of the rule suggest that EPA intends the LEE provisions to apply to all subcategories, but monitoring requirements for other HAPs and fuels are not specified in Table 5. We request that the final rule explicitly include LEE thresholds and compliance requirements for all subcategories and HAP groups, with specific recommendations below.

i. Low-Emitting Units: Mercury

For mercury, the rule states that a LEE must conduct "at least three nominally equal length" test runs over a 28 to 30-day test period, using Method 30B, to determine the mercury emissions of the unit (lb/TBtu or lb/GWh). Table 5 requires that a company then calculate its annual mercury emissions based on the "potential maximum annual heat input" or "potential maximum electricity generated". For example, a coal unit meeting the proposed mercury emissions limit for units designed to combust coal with a heat content ≥ 8,300 Btu/lb (1.0 lb/TBtu) would emit just under 22.0 lbs per year of mercury, assuming a capacity of 250 MW, a heat rate of 10,000 Btu/KWh, and a capacity factor of 100 percent. Alternatively, a larger unit could operate at 10 percent of the mercury emissions rate limit, or 0.12 lb/TBtu, and exceed 22.0 pounds per year.

To maintain LEE status and demonstrate continuous compliance a unit must: (1) conduct fuel sampling and analysis according to Table 6 and §63.10008 at least every month; (2) operate within the operating limits established during the 28- to 30-operating day performance test; and (3) repeat the performance test once every five years according to Table 5 and §63.10007. Our understanding of the rule is that monthly fuel tests would be compared against the inlet fuel that was burned during the mercury emissions performance testing. This fuel content value from the initial performance testing becomes the unit's maximum fuel inlet operating limit for mercury.

The Clean Energy Group recommends an additional, alternative method for demonstrating continuous compliance for mercury when a unit qualifies for LEE status. As an alternative to conducting monthly fuel tests, we propose that owners/operators of a LEE unit have the option to conduct an annual Method 30B performance test to demonstrate that its emissions are less than 10 percent of its applicable mercury emissions limit or less than 22.0 pounds per year. If a LEE unit exceeds LEE limits, we propose that it revert back to more frequent performance tests (e.g., quarterly, as recommended above). The subsequent year, if the unit can, again, demonstrate LEE status through reduced utilization or a lower emission rate, it would return to annual stack tests under the LEE provisions. We recommend this alternative, annual stack testing instead of monthly fuel testing, to balance the need for accurate emissions data with reduced compliance costs for those units emitting at a fraction of the proposed standards.

Also, in order to avoid having companies run units simply to conduct stack testing, we propose that LEE units have the flexibility to schedule their annual performance tests at any time during a 12-month cycle. Some of these LEEs may be smaller units with low capacity factors and may go several months without operating. Allowing flexibility in scheduling stack tests will avoid unnecessary HAP emissions and reduce costs for these units operating well below the proposed standard. Additionally, this would allow companies to align testing under this rule with existing state testing requirements.

ii. Low-Emitting Units: Other HAPs

EPA proposes that for all other HAPs, LEEs would demonstrate continuous compliance and maintain LEE status through monthly fuel analysis as well as performance (stack) testing every five years. However, in many cases, monthly fuel testing would be redundant as this requirement would result in the repetitive testing of the same fuel shipment (see further discussion below in the context of oil-fired units). Therefore, we recommend that for non-mercury HAP as well, owners/operators of a LEE unit have the option to conduct an annual performance test to demonstrate that emissions are less than 50 percent of the relevant emissions standard.

f. Startup, Shutdown, and Malfunction

As indicated in the preamble, in *Sierra Club v. EPA*, 551 F.3d 1019 (DC Cir. 2008), the DC Circuit Court vacated portions of the Section 112 regulations, commonly known as the "General Provisions Rule," which had previously exempted major sources from NESHAP during periods of startup, shutdown, and malfunction (SSM).

In the EGU MACT rule, EPA proposes that the emissions standards for mercury and other air toxics apply at all times, including periods of SSM. According to the preamble, EPA has not proposed different standards for SSM periods because (1) the Agency has taken into account startup and shutdown periods in setting the standards; (2) the standards proposed are 30 boiler operating day averages; (3) EGUs do not normally start up and shut down frequently; and (4) EGUs typically use cleaner fuels (e.g., natural gas or oil) during the startup period.

While EPA's assumptions regarding startup and shutdown are sometimes correct, we believe that there may be periods when a source would be unable to comply with the applicable NESHAP standards despite their best efforts because they do not switch to cleaner fuels during shutdown or pollution control devices do not operate at peak performance until steady-state operation is achieved. Most EGUs will combust natural gas or No. 2 fuel oil (or both) at startup before switching to coal or residual fuel oil. However, in terms of shutdown, units will either reverse the sequence (switching from coal or residual oil to natural gas or No. 2 oil) or simply shut down on whatever fuel they happen to be burning at the time. As a result, there may be EGUs that would not switch to lower emitting fuels during shutdown. Also, pollution control systems may not achieve peak performance at startup, temporarily limiting a unit's ability to limit its emission rate. We do not believe that such situations were ever reflected in the Information Collection Request (ICR) stack testing. Finally, EPA's assumption that EGUs can simply average their emissions over 30 boiler operating days is only relevant in the context of an EGU using a continuous emissions monitoring device. An EGU that demonstrates compliance with a monthly or quarterly performance test would not be in a position to average its emissions during periods of startup and shutdown because it would not be feasible to measure emissions during these periods.

Therefore, we recommend that, in the final rule, EPA follow the approach that it used in the final National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (ICI Boiler MACT); namely, that work practice standards apply during periods of startup and shutdown to minimize air pollution emissions, while malfunctions would not be considered a distinct operating mode.[3] In the ICI Boiler rule, EPA determined that it is not technically feasible to monitor these periods of startup and shutdown and therefore established separate work practice standards for periods of startup and shutdown. In the ICI Boiler rule, EPA requires operators to follow manufacturers' specifications for minimizing periods of startup and shutdown. Specifically, 40 CFR 63.7530(h) requires that owners/operators of covered ICI boilers "minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a unit of similar design if manufacturer's recommended procedures are not available." We believe a similar approach, which requires an affected EGU to minimize periods of startup and shutdown and associated emissions, is appropriate for EGU boilers, recognizing that in most cases emissions will be below the applicable NESHAP standards by virtue of the lower emitting fuel.

In terms of malfunctions, which are sudden, infrequent, unexpected, and not reasonably preventable, we recommend that EPA or states maintain current enforcement discretion to address situations in which a source fails to comply with a 112(d) standard as the result of a malfunction. We expect that, as in current practice, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction). As EPA notes in the preamble to the ICI Boiler rule, "even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard." Therefore, in the ICI Boiler rule, EPA finalized an affirmative defense to civil penalties for exceedances of numerical emission limits caused by malfunctions (40 CFR 63.7575 defining "affirmative defense").

[3] Calpine Corporation will be filing separate comments expressing an alternative view on this issue.

II. Recommendations for Coal-Fired EGUs

a. Subcategories

The Clean Energy Group supports EPA's proposed subcategories for coal-fired EGUs. EPA has proposed two basic subcategories for coal-fired EGUs: (1) EGUs designed for coal ≥ 8,300 Btu/lb, and (2) EGUs designed for coal < 8,300 Btu/lb. For mercury emissions, EPA has proposed different emissions limits for the two subcategories. For all other HAPs, EPA has proposed the same emissions limits for the two subcategories.

Section 112 allows EPA to subcategorize by size, class, or type, and any basis for subcategorization is generally related to an effect on emissions. The Agency developed a robust database of stack emissions data from more than 300 coal units. As a result, EPA had an extensive database on which to base its decision and we believe the proposed subcategories for coal are consistent with the requirements of the Act.

b. Emissions Standards for Existing Coal EGUs

i. Mercury

The Clean Energy Group recommends that EPA finalize the mercury emissions standards as proposed for existing coal EGUs. The proposed mercury standards for coal-fired units are reasonable, as evidenced by the fact that at least 13 states have or will have mercury emission standards equal to or more stringent than EPA's proposal. Based on our analysis of the 178 coal units (≥ 8,300 Btu/lb) that conducted stack emissions testing in 2010 as part of EPA's ICR emissions testing program, we found that nearly 60 percent are currently achieving the proposed mercury emissions standard. This translates to more than 100 units (out of a total of 178).

We also support allowing existing sources the option to comply with the input- or output-based standards, and recommend that EPA maintain this flexibility in the final rule.

ii. Metals (PM)

The Clean Energy Group supports EPA's use of Total PM as a surrogate for non-mercury metal HAPs. As EPA notes in the rule's preamble, controls targeting PM will reduce emissions of non-mercury metal HAPs, with greatly-reduced monitoring costs.

The Clean Energy Group recommends that EPA finalize the Total PM emissions standard as proposed for existing coal EGUs; i.e., 0.030 lb/mmBtu or 0.30 lb/MWh. Based on our analysis of the 172 coal units that conducted stack emissions testing in 2010 as part of EPA's ICR emissions testing program, we found that nearly 70 percent of all coal-fired generating units that submitted stack test data to EPA are currently achieving the proposed Total PM emissions standard. This translates to more than 119 units (out of a total of 172).

The Clean Energy Group supports allowing existing sources the option to comply with the input-or output-based standards, and recommend that EPA maintain this flexibility in the final rule.

iii. Acid Gases (HCl)

The Clean Energy Group supports EPA's use of HCl as a surrogate for all acid gases. As EPA notes in the rule's preamble, controls targeting HCl will reduce emissions of all acid gases, with greatly-reduced monitoring costs.

The Clean Energy Group recommends that EPA finalize the HCl emissions standard as proposed for existing coal EGUs; i.e., 0.0020 lb/mmBtu or 0.020 lb/MWh. Based on our analysis of the 217 coal units that conducted stack emissions testing in 2010 as part of EPA's ICR emissions testing program, we found that more than 70 percent of all coal-fired generating units that submitted stack test data to EPA are currently achieving the proposed HCl emissions standard. This translates to 158 units (out of a total of 217).

We also support allowing existing sources the option to comply with the input- or output-based standards, and recommend that EPA maintain this flexibility in the final rule.

c. Compliance Requirements

Overall, the Clean Energy Group appreciates EPA's efforts to establish reasonable emissions limits with adequate compliance demonstrations. However, EPA's proposed testing requirements are very burdensome, and we believe the Agency could achieve an equivalent level of compliance assurance with a lower compliance burden with the following adjustments to the proposal.

i. General Compliance Demonstrations

Under the proposed rule, coal-fired units would be required to conduct monthly or bimonthly stack testing to demonstrate compliance with non-mercury HAPs (mercury demonstrations would utilize Hg CEMS or sorbent traps). For the reasons described above, all stack testing requirements should be no more frequently than quarterly under standard operation (i.e., unless boiler operations or characteristics are substantially altered, in which case initial testing would be required to be repeated). We recommend that a coal-fired unit must run on a regulated fossil fuel (e.g., coal or oil) at least 168 hours in a calendar quarter to trigger stack testing requirements for non-mercury HAP groups, such as metals and acid gases.

ii. PM

Specifically, we recommend a change to the proposed rule's treatment of condensable PM (CPM) for units using PM CEMS. As proposed, sources would be required to conduct initial testing to determine emissions of total PM as well as its constituents, filterable PM and CPM. These would be used to establish a facility-specific filterable PM limit as a surrogate for total PM. For instance, if the initial compliance demonstration for Facility A, an existing coal-fired power plant with heat input ≥ 8,300 Btu/lb, showed total PM emissions of 0.020 lb/MMBtu with 50 percent filterable and 50 percent CPM, a facility-specific filterable PM limit of 0.010

lb/MMBtu would be established. However, an identical Facility B with the same Total PM emissions but a higher ratio of filterable to CPM, such as 75 percent, would establish a filterable PM limit of 0.015 lb/MMBtu. This method is inherently uncertain, and could result in a facility having a variable emissions target. Additionally, this method results in unfairly "ratcheting down" the standard on some units. While the Clean Energy Group recognizes EPA's obligation to address CPM, which may include vapor-phase metals such as selenium, this compliance approach introduces a new set of problems.

Therefore, we propose the following options for EPA consideration:

- PM CEMS combined with occasional stack tests to ensure CPM emissions remain within limits.
- Use mercury as a surrogate for selenium and, thus, filterable PM alone may be a surrogate for other HAP metals. In the preamble, EPA states that selenium is captured by controls for mercury and acid gases. In fact, our initial correlation analysis indicates that selenium emissions are in fact better-correlated to mercury and acid gas emissions than CPM ($r=0.44$ for mercury or 0.60 for HCl, versus 0.32 for CPM [$r > 0.2$ implies significance at 5 percent level with 60 units]).
- PM CEMS combined with a separate selenium (Se) standard. In this instance, selenium emissions could be confirmed by quarterly or annual stack testing limited to selenium. Similar to the treatment of limited use units, this requirement could be scaled such that units emitting Se well below the standard were subject to less stringent monitoring requirements than those units emitting very close to the standard.

Alternatively, at a minimum, we recommend that EPA base the filterable PM limit on the facility-specific ratio to the total PM standard, rather than the initial numerical performance. In the above example, Facility A's emissions of 50 percent filterable PM would result in a limit of 0.015 lb/MMBtu (50 percent of the 0.030 lb/MMBtu standard), while Facility B's limit would be 0.0225 lb/MMBtu (75 percent of the 0.030 lb/MMBtu standard). We also recommend that this facility-specific limit remain constant for a longer period of time, such as annually, to provide a measure of regulatory certainty.

iii. Sorbent Traps for Mercury

The Clean Energy Groups supports EPA's proposal to allow the use of sorbent traps to demonstrate compliance with the mercury emissions limits for coal-fired EGUs. While units with existing or planned CEMS anticipate using them for demonstrating compliance with the proposed rule, EPA should not assume that most coal-fired EGUs have mercury CEMS as stated in the preamble.

iv. Operating Limits

§ 63.10011 of the proposed EGU MACT rule requires coal-fired EGUs (and oil-fired EGUs) to establish "parameter operating limits" in order to demonstrate continuous compliance. The operating limits would be established during initial compliance testing. The requirements vary depending on the pollution control technology used by the unit to demonstrate compliance, as summarized in Table 1 below.

Table 1. Proposed Operating Limits

Control Device	Operating Limits
Wet Scrubber (PM)	Maintain pressure drop and liquid flow rate
Wet Scrubber (acid gases)	Maintain the pH and liquid flow rate
Fabric filter	Install and operate a bag leak detection system
ESP	Maintain secondary voltage and secondary amperage
Dry Scrubber	Maintain sorbent injection rate
Dry sorbent injection	Maintain sorbent injection rate
Carbon injection control	Maintain sorbent injection rate
Fabric filter	Install bag leak detection system and limit bag leak detection alarms

We have several concerns with the proposed parameter operating limits and recommend an alternative approach that we think will better ensure proper operation of pollution control systems. Our primary concerns can be summarized as follows: (1) parameter operating limits may be unnecessary, adding additional compliance costs, for an affected EGU that is already demonstrating compliance with a continuous emissions monitoring device; (2) parameter operating limits may be duplicative or redundant with existing, EPA-approved Compliance Assurance Monitoring (CAM) plans; and (3) a numeric operating limit, established during initial compliance testing, could set an unreasonable limit that fails to reflect the full variability of the plant's operating conditions.

For example, the proposed rule requires a plant operator to measure the voltage and current of each ESP collection field during each mercury, PM, and metals performance test. The average of the three minimum hourly values would then be used to establish a unit's site-specific minimum voltage and current operating limits for the ESP. While we agree that maximizing power input and electric field strength will generally maximize ESP collection efficiency, plant operators need a degree of flexibility to balance the power input to the ESP in order to avoid serious damage to the system and downtime. The power input to an ESP is dynamically controlled by an automated voltage control system to maximize power levels while avoiding sustained arcing or sparking between the electrodes and the collecting plates, which can damage the ESP, including the transformer-rectifier and other components in the primary circuit. Automatic voltage control varies the power to the transformer-rectifier in response to signals received from sensors in the precipitator and the transformer-rectifier itself. Power levels will vary depending on the amount of moisture in the air, accumulated ash levels, and other factors. As result, sustaining a minimum voltage and current level may not be possible or appropriate at all times, and could damage the control technology.

Rather than establishing fixed operating limits, we recommend that EPA require proper operation of the plant's pollution control equipment and appropriate parametric monitoring without establishing numeric operating limits. Also, units with appropriate CAM plans and units operating CEMS should not be required to have additional monitoring requirements.

Also, we would note that there appear to be inconsistencies between the operating limits specified in § 63.10011, Table 4 to Subpart UUUUU of Part 63, and Table 7 to Subpart UUUUU of Part 63. Page 25030 of the preamble states that the operating limits for an ESP would be based on the "minimum hourly values" for each test run; however, Table 7 to Subpart UUUUU of Part 63 requires sources to "collect secondary voltage and current...every 15 minutes during the entire period of the performance test…determine the average hourly total secondary power inputs for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run." These two statements seem to be in conflict. Also, Table 7 to Subpart UUUUU of Part 63 only lists the operating limits for ESPs for units that operate wet scrubbers. The table does not include the operating parameters for a unit with an ESP, but no wet scrubber. Also, the table references § 63.10011(c); this appears to be an error. That section deals with fuel analysis. Table 8 to Subpart UUUUU of Part 63 also references § 63.10011(c).

Finally, it is not clear from the proposed rule what the requirements or response action would be in the event that a unit violated its parameter operating limits. We would propose that a facility initiate a corrective action to address the excursion similar to what is required in 40 CFR 64 for Compliance Assurance Monitoring.

III. Recommendations for Oil-Fired EGUs

The following recommendations are specific to the proposed standards for oil-fired EGUs. Although oil-fired generation represents a small fraction of total electricity production in the U.S., several of the Clean Energy Group companies have significant oil-fired generating capacity, including Consolidated Edison, National Grid, NRG Energy, Public Service Enterprise Group, and NextEra Energy. Exelon Corporation is not a signatory to this section of the comments, and the comments that follow should not be read as reflecting the company's views on the rule.

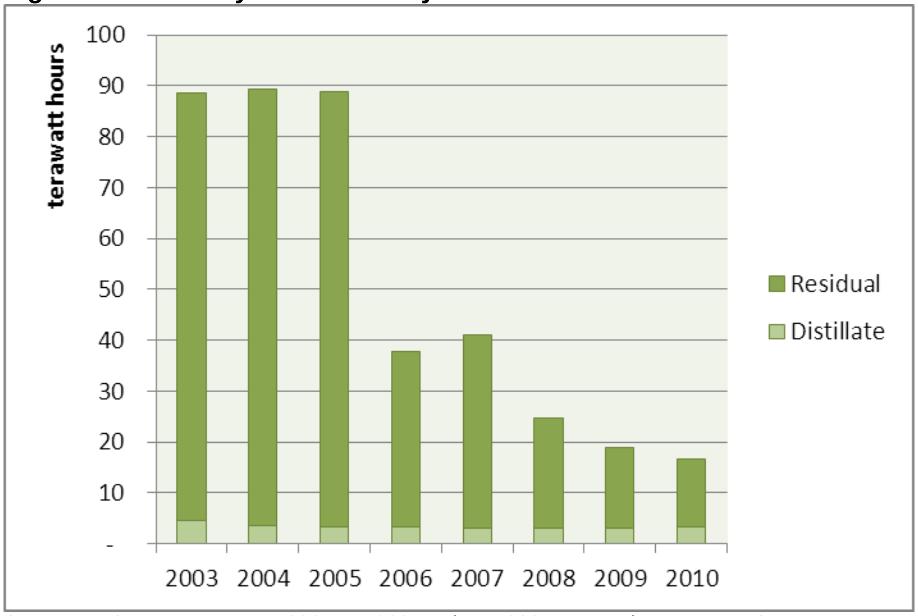
In the United States, oil-fired EGUs generally operate as peaking or load-following units, and only produce about one percent of electric power output. In 2003, oil-fired EGUs (steam) produced 88.5 terawatt hours of electricity. By 2010, this share had declined by 80 percent, to less than 17 terawatt hours. Figure 1 shows the decline in oil use by steam EGUs based on U.S. Energy Information Administration (EIA) data. Residual (No. 6) oil is the most widely used fuel oil for generating steam and electricity because of its relatively low cost compared to lighter distillate fuel oils.

Although the use of oil has been declining, in the areas where fuel oil is used for electricity production, it often serves a vital role in terms of maintaining electric system reliability. For example, in the Northeast region, oil is often the only fuel available when natural gas supplies are curtailed in favor of residential and commercial natural gas customers. In addition, during high electric demand days, select units are sometimes obligated by state and regional Reliability Councils or ISOs to fire oil even when natural gas is available, to ensure electric system reliability in the event of a gas supply interruption. Further, as a result of geographic isolation, the majority of electricity generation in Hawaii and Puerto Rico is from oil-fired power plants.

According to the EGU MACT proposal, oil-fired EGUs produced 1,779 tons of priority HAPs in 2010. This compares to 181,287 tons produced by coal-fired EGUs.[4] HAP emissions from oil-fired EGUs represent one percent of the HAP emissions from the two subcategories, according to EPA estimates.

[4] U.S. EPA. National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units. 76 FR 24983.

Figure 1. Electricity Generation by Oil-Fired EGUs



Source: U.S. EIA. Form EIA-906, EIA-920, and EIA-923 Data. Prime Mover = Steam.
Note: There are only three power plants in the U.S. with steam units that rely exclusively on distillate fuel oil for electricity generation. These units account for less than one percent of the distillate oil-fired generation displayed above. Most of the distillate oil use shown in the chart above is combusted at coal-fired steam boilers.

a. Subcategorizing Between Coal- and Oil-Fired EGUs

The Clean Energy Group supports EPA's decision to subcategorize between coal- and oil-fired EGUs given the different operating characteristics and emissions profiles of the two subcategories. As indicated above, oil-fired EGUs generally operate as peaking or load-following units. Coal-fired power plants generally operate as baseload generating resources. According to EPA's ICR database, oil- and coal-fired EGUs report annual average capacity factors of 19 percent and 63 percent, respectively.[5]

In structuring the final rule, we encourage EPA to better separate the compliance and monitoring requirements applicable to oil-fired EGUs from the requirements for coal-fired EGUs to ensure that the requirements for both subcategories are fully developed and articulated. For example, as discussed above, the requirements for oil-fired LEEs are not specified in the proposal. We believe that better separation of the requirements for coal- and oil-fired EGUs will reveal where these gaps may be occurring.

b. Risk Assessment of Oil-Fired EGUs

In developing the proposed EGU MACT Rule, EPA prepared an updated assessment of the chronic inhalation risks associated with certain HAP emissions from coal- and oil-fired EGUs. EPA evaluated 16 case study facilities, including one residual oil-fired power plant in Hawaii. In the preamble of the rule, EPA indicates that it also plans to complete a peer review assessment of

[5] U.S. EPA. ICR Database: Part I – Boiler_Information. Companies were asked to report their average annual capacity factors and hours of operation for the past three years (2007-2009).

the chemical speciation of nickel emissions used in the updated risk assessment for non-mercury HAPs.

The Clean Energy Group encourages EPA to complete this review of the nickel speciation assumptions because new scientific studies have been published regarding the toxicity of nickel emissions from oil-fired EGUs. For example, the Department of Energy's final report entitled *Nickel Species Emission Inventory For Oil-Fired Boilers* (2004) found that "The presence of … nickel oxide compound mixtures and lack of carcinogenic nickel subsulfide (Ni_3S_2) or nickel sulfide compounds (e.g., NiS, NiS_2) in [residual oil fly ash] stack-sampled from 400- and 385-MW boilers are contrary to EPA's nickel inhalation cancer risk assessment (Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, February 1998), where it is assumed that the nickel compound mixture emitted from oil-fired utilities is 50 percent as carcinogenic as Ni_3S_2 [i.e., that 50 percent of nickel emitted was in the form of Ni_3S]. Apparently, this assumption greatly overestimates the nickel inhalation cancer risk from oil-fired utilities." An updated study has also been published evaluating the nickel species that are emitted by residual oil-fired EGUs.[6]

Also, EPA's updated risk assessment and the 1998 Report to Congress focuses exclusively on residual oil-fired EGUs. There is no discussion or analysis in the report supporting the inclusion of distillate oil-fired EGUs in the December 2000 Appropriate and Necessary Finding. In fact, the only reference to distillate oil in the 1998 Report to Congress is a statement suggesting that distillate oil is more similar to natural gas than residual oil. EPA indicates that "natural gas and distillate oil" both contain relatively little fuel-bound nitrogen. For natural gas-fired EGUs, EPA found that regulation of HAP emissions is not appropriate or necessary because the impacts due to the HAP emissions from such units are negligible based on the results documented in the Report to Congress. We would also note that the Report to Congress is clear that its inhalation risk analysis—which EPA uses to justify the regulation of oil-fired EGUs—is specific to No. 6 residual oil. As indicated in Table 6-25 of the Report to Congress (the basic parameters used in the inhalation risk assessment for utilities), EPA assumed an "average HAP concentration in test data of residual fuel oil No. 6".[7] Also, among the 11 oil-fired EGUs listed as potentially posing inhalation risks above the threshold of concern, none rely on distillate fuel oil. EPA lists only three power plants in the entire U.S. that rely on distillate fuel oil for the production of electricity. As a result, we recommend that EPA reevaluate its decision to include distillate oil-fired EGUs in the EGU MACT Rule.

c. Definition of Fossil Fuel-Fired EGUs

The Clean Energy Group generally supports EPA's proposed definition of a "fossil fuel-fired EGU"—using the construct from the Acid Rain Program. However, we do propose certain modifications to the proposal, which we ask EPA to consider.

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[6] Huggins, Frank; Galbreath, Kevin; Eylands, Kurt; Van Loon, L.; Olson, Jeremy; Zillioux, Edward; Ward, Stephen; Lynch, Paul; Chu, Paul, "Determination of nickel species in stack emissions from eight residual oil-fired utility steam-generating units," Environmental Science & Technology, Volume 45, (2011), accepted for publication.

[7] U.S. EPA. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, February 1998. Volume 1: Page 6-61.

EPA proposes that a unit must have fired a fossil fuel (other than natural gas) for more than 10.0 percent of the average annual heat input during the previous three calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years to be considered a "fossil fuel-fired" EGU subject to the proposed rule. A unit that burns natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous three calendar years or 85 percent or more of the annual heat input during any one of those calendar years, the unit is considered to be natural gas-fired and would not be subject to the proposed rule.

The Clean Energy Group recommends a limited exception when defining a fossil fuel-fired unit that would address natural gas curtailment situations and gas supply emergencies where a dual-fired generating unit (for example, capable of combusting both natural gas and oil) is required to combust a fossil fuel (other than natural gas), either due to a natural gas supply interruption as in the ICI Boiler MACT or due to requirements unique to the electric industry in which an authority, such as a state PUC or Reliability Council or ISO, requires selected units to burn a fossil fuel (other than natural gas) to ensure electric system grid stability.

Consistent with the ICI Boiler MACT, the Clean Energy Group proposes excluding the fossil fuels combusted during a period of natural gas curtailment or according to a reliability directive when determining if a unit is a "fossil fuel fired" EGU subject to the proposed rule. The ICI Boiler MACT defines a "*period of natural gas curtailment or supply interruption*" as a "*period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption*" (76 FR 15685).

Specifically, the Clean Energy Group recommends expanding the text to define "*period of natural gas curtailment or supply interruption*" as a "*period of time during which the supply of natural gas to an affected facility is limited for reasons beyond the control of the facility*, ***including when a unit is obligated to run on fossil fuel (other than natural gas) by local reliability rules****. […]*". This addition, as well as the language from the ICI Boiler MACT, would exclude fossil fuel consumed as a result of (1) an emergency situation when natural gas supplies are physically interrupted; (2) a contractual agreement that limits a unit's natural gas supply; and/or (3) mandated operating rules requiring a unit to limit the use of natural gas to ensure electric system reliability.

The Clean Energy Group only intends this exemption to apply in a limited set of circumstances when there is a genuine threat to the reliability of the electric power system. For example, the New York State Reliability Council has established reliability rules and operating procedures that obligate certain units on Long Island and downstate New York to switch from natural gas to oil (regardless of economics) in order to protect the reliability of the bulk power system.[8] Reliability rules require that New York City and Long Island have detailed plans in place to

[8] NYSRC. NYSRC Reliability Rules for Planning and Operating the New York State Power System. Version 29. January 7, 2011.

maintain electricity supplies in the event that there is a loss of natural gas supplies. For example, on Long Island, the I-R5 reliability plan requires at least one of the Northport Generating Station units to run on oil if all the three following conditions occur: (1) the Northport-Norwalk Harbor Cable (NNC) is out of service, (2) electrical load on the island exceeds 2,751 MW, and (3) two of the Northport Generating Station units are on-line. These requirements may be changed in the future in response to changes in the transmission system, load conditions and/or changes in the generation system. In New York City, there are nine units that report combusting oil in response to the I-R3 reliability rules between January 1, 2009 and August 31, 2010. The total number of hours that they were subject to minimum oil burn requirements is fairly low—although these were critical run times for the reliability of the system. The average was 653 hours over these 18 months (4.5 percent).

Also, the Clean Energy Group recommends allowing companies to determine whether they are "natural gas-fired" or "fossil fuel-fired" at either the individual unit level or across all electric utility steam generating units larger than 25 MW at a single plant location. For example, a power plant with multiple steam generating units may be combusting limited amounts of oil across the plant as a whole, but with an individual unit burning oil in excess of EPA's proposed thresholds. This would avoid situations where a relatively small oil unit might be designated a fossil fuel-fired EGU despite the fact that the plant as a whole is largely reliant on natural gas and its plant-average emission rates are well below the level of the proposed standards. This would seem to be consistent with EPA's proposal to allow emissions averaging across all affected units at a single plant location.

Finally, the Clean Energy Group companies seek clarification on the compliance requirements for units that may change from being "natural gas-fired" to "fossil fuel-fired". As described above, a natural gas-fired generating unit may be forced to combust oil to maintain electric system reliability, and could suddenly change from being an unregulated natural gas-fired unit to a regulated fossil fuel-fired generating unit (if EPA does not adopt the above-proposed definition for curtailment). Outside of curtailment situations, a dual-fired unit may also burn oil if prices are competitive relative to natural gas or for other reasons. The proposed rule is unclear with regard to how much time EPA would allow a newly-designated fossil fuel-fired unit to schedule and perform its initial performance tests to demonstrate compliance with the applicable standards.

d. Limited Use Subcategory for Oil-Fired Units

The Clean Energy Group supports establishing a limited-use subcategory for oil-fired EGUs. We believe the stack emissions testing requirements would not be feasible for these low oil capacity factor units. EPA indicates in its proposal that it is considering a limited-use subcategory to account for liquid oil-fired units that only operate a limited amount of time per year on oil. According to EPA, such units could have specific emission limitations or reduced monitoring requirements (for example, limited operation may preclude the ability to conduct proper stack emissions testing).

EPA included a limited-use subcategory in the final ICI Boiler MACT.[9] As stated in the preamble, "EPA agrees that a subcategory for limited use units is appropriate for many of the reasons stated by the commenters. The fact that the nature of these units is such that they operate for unpredictable periods of time, limited hours, and at less than full load in many cases has led EPA to determine that limited use units are a unique class of unit based on the unique way in which they are used and EPA is including a subcategory for these units in the final rule. The unpredictable operation of this class of units makes emission testing for the suite of pollutants being regulated impracticable. In order to test the units, they would need to be operated specifically to conduct the emissions testing because the nature and duration of their use does not allow for the required emissions testing. As commenters noted, such testing and operation of the unit when it is not needed is also economically impracticable, and would lead to increased emissions and combustion of fuel that would not otherwise be combusted. Therefore, we are regulating these units with a work practice standard that requires a biennial tune-up, which will limit HAP by ensuring that these units operate at peak efficiency during the limited hours that they do operate." (76 FR 15634)

We recommend the following definition for a limited-use oil-fired EGU: A *limited-use oil-fired EGU* means any boiler that burns any amount of liquid oil, has a rated capacity of greater than 25 MW, and has an annual average capacity factor based on its oil use of 10.0 percent or less over the past three years (and not more than 20.0 percent in each of those three years).[10] This is the same general approach that EPA uses for defining "gas-fired and oil-fired peaking units" in Part 75. Borrowing from 40 CFR 72.2, we would define "capacity factor" as the ratio of the unit's actual annual oil heat input to the unit's maximum design heat input times 8,760. We believe that this is a reasonable threshold for defining limited use for oil-fired EGUs because of the existing regulatory precedent in the Clean Air Act and because, unlike a threshold based on hours of operation, it reflects the varying loads of an electric generating unit.

We base our recommendation for a limited use subcategory on the same logic that EPA articulated in the ICI Boiler MACT, that "the nature of these units is such that they operate for unpredictable periods of time, limited hours, and at less than full load in many cases has led EPA to determine that limited use units are a unique class of unit based on the unique way in which they are used."

We do not support establishing an equivalent limited use subcategory for coal-fired EGUs because of their higher HAP emissions rates, higher average capacity factors, and higher average capacity size (i.e., greater potential to consume larger amounts of fuel). In contrast to the vast majority of coal-fired units, oil-fired EGUs in the continental U.S. tend to be used for peaking, voltage support, or to ensure fuel diversity during winter months. According to EPA's ICR database, oil- and coal-fired EGUs report annual average capacity factors of 19 percent and 63

[9] Under the ICI Boiler MACT, a limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, and has a federally enforceable limit of no more than 876 hours per year of operation (i.e., 10 percent utilization). Limited use boilers or process heaters must conduct a biennial tune-up, but are not subject to a numeric emissions limit.

[10] Most units would not have a federally enforceable limit in place restricting their hours of operation on oil. We seek clarification from EPA in terms of whether this would be required to qualify as a limited-use oil-fired EGU.

percent, respectively.[11] Also, oil-fired EGUs are smaller, on average, than coal-fired EGUs. The average oil-fired EGU is less than 300 MW.[12] The average coal-fired EGU is 440 MW.[13] According to EIA, oil steam generating units produced only about 17 terawatt hours of electricity in 2010.[14] In contrast, coal-fired generating units produced 1,835 terawatt hours of electricity in 2010—more than 100 times greater.[15]

e. Emissions Standards

i. Metals

The Clean Energy Group recommends that EPA re-evaluate the proposed Total HAP Metals standard for existing oil-fired EGUs. The current proposed standard was calculated based on seven units, most of which were burning light distillate fuel oil during ICR testing. EPA lists only three power plants in the entire U.S. that rely on distillate fuel oil for the production of electricity; the vast majority of oil-fired EGUs combust heavier residual oil. As a result, the Clean Energy Group believes that EPA has proposed a standard that is not reflective of the subcategory and not reasonably achievable. Nine units with ESPs and five units that were combusting a combination of natural gas and oil during ICR testing report emission rates well above EPA's proposed standard. In contrast, more than 70 percent of coal-fired EGUs in the ICR database meet EPA's proposed standard for Total PM.

Additionally, we request that EPA reconsider its decision not to propose a PM standard for liquid oil-fired EGUs. In light of the various data corrections outlined below, we recommend that EPA consider setting a PM limit for liquid oil-fired EGUs to control Total HAP metals. Figure 2 below shows that units equipped with ESPs—for PM control—generally have the lowest reported Total HAP Metals emission rates. This suggests that a PM limit would be a reasonable surrogate for Total HAP Metals for oil-fired EGUs. Liquid oil-fired EGUs would have the option of complying with a PM limit, a Total HAP Metals limit, or individual HAP Metal limits.

Errors and Missing Data in the ICR Database

The Clean Energy Group has identified several data errors and missing test results in the spreadsheet summarizing EPA's MACT floor analysis for oil-fired EGUs including, notably, incorrect fuel designations:

- EPA's spreadsheet entitled "floor_analysis_oil_031611.xlsx" lists Mitchell Power Station Units 001 and 003 as combusting "No.6 Fuel Oil (residual or bunker C)". This information is incorrect based a review of the facility's test reports contained in the docket. The Mitchell units burn distillate fuel oil.

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[11] U.S. EPA. ICR Database: Part I – Boiler_Information. Companies were asked to report their average annual capacity factors and hours of operation for the past three years (2007-2009). In fact, the average capacity factor for oil-fired EGU may be even lower because the reported values would also reflect natural gas consumption.
[12] *Id.*
[13] *Id.*
[14] U.S. EIA. Form EIA-906, EIA-920, and EIA-923 Data.
[15] *Id.*

- The test reports for the Suwannee River Power Plant indicate that Units 2 and 3 were combusting "Distillate Fuel Oil (Grades 1 and 2)" during ICR testing. However, based on a call to the plant operator, we have determined that both units were combusting residual fuel oil.

- Based on discussions with industry colleagues, we would also highlight that Middletown Unit 2 and Norwalk Power Unit 2 both have ESPs installed. EPA's spreadsheet (floor_analysis_oil_031611.xlsx) only lists the NOx controls installed at the units.

- Turkey Point 2 tested for Total HAP metals as part of the ICR; however, the unit does not appear in EPA's oil floor analysis spreadsheet.

- Emissions test reports from the Puerto Rico Electric Power Authority (8 units) were not included in the MACT floor analysis because of a late submission. We recommend that EPA include these additional data points in its MACT floor analysis.

- At least two units (Eagle Valley 1 and 2) in the MACT floor for Total HAP Metals do not appear to report cobalt emissions. As a result, their Total HAP Metal emission rates appear artificially low. Additionally, six units from the Puerto Rico Electric Power Authority did not appear to report cobalt emissions. This omission identifies potentially inconsistencies in the metals testing and development of the proposed standards.

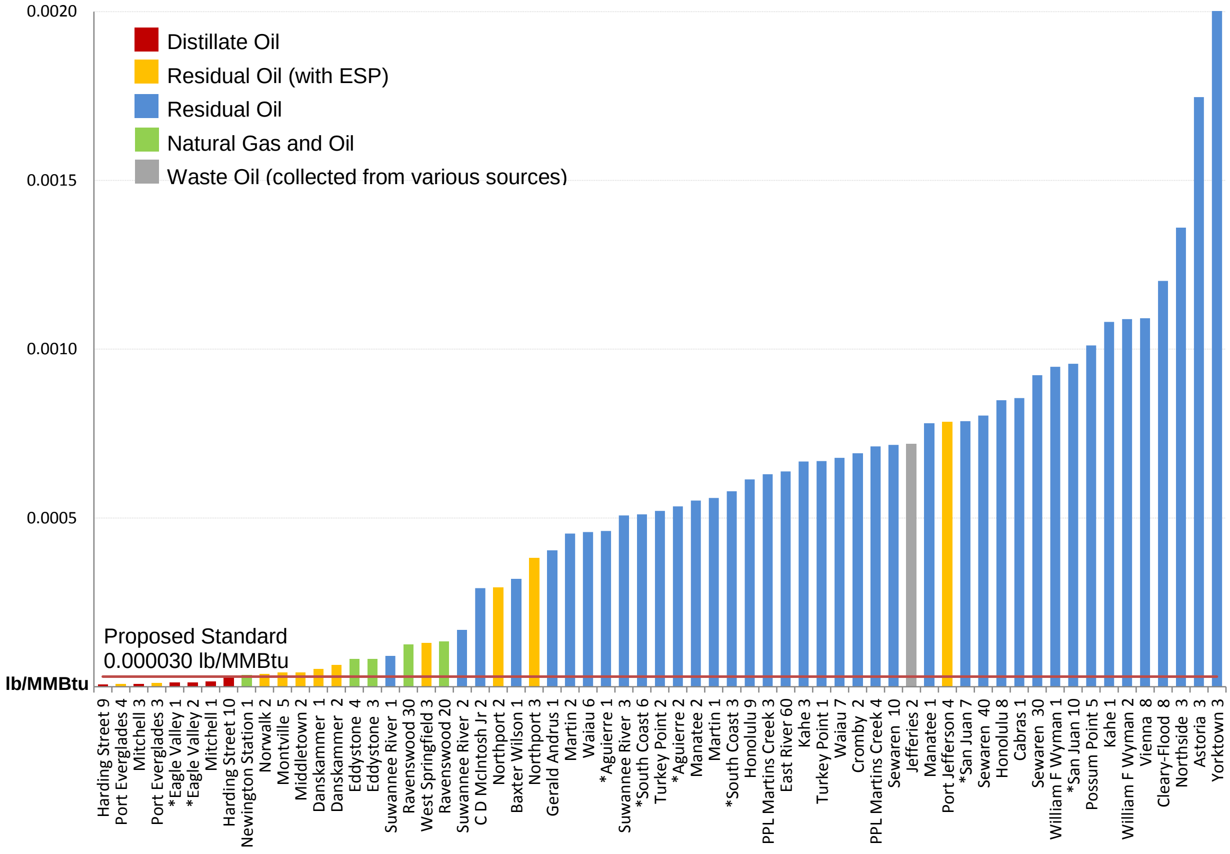
- Similarly, Harding Street 9 has a zero value for one Beryllium test run, which appears to be averaged in as zero rather than dropped or substituted with the detection limit value.

- Finally, in separate comments, NRG has submitted corrected HAP Metals emissions data for Norwalk Unit 2, Montville Unit 5, and Middletown Unit 2. The errors overstated the units' HAP Metals emission rates.

The corrected data, to the extent that we have been able to identify problems in the database, are summarized in Figure 2 below. The current proposed standard (0.000030 lbs/MMBtu), also shown in Figure 2 below, was calculated based on seven units, most of which were burning distillate fuel oil during ICR testing. Apart from the two Port Everglades units, all of the units that established the MACT floor for Total HAP Metals were combusting distillate fuel oil. In some cases, these units were burning low sulfur distillate fuel oil. Eagle Valley, for example, specifies low sulfur (0.05%) distillate fuel oil and most shipments received by the facility contain less than 0.03% sulfur. Also, the ESPs at the Port Everglades facility were recently installed (construction was completed in 2006). However, nine units with ESPs and five units that were combusting as much as 75 percent natural gas during ICR testing report emission rates above EPA's proposed standard (units known to be combusting natural gas during the ICR testing are shown in green in the figures below).

The Clean Energy Group recommends that EPA post a revised spreadsheet on the Utility MACT website, reflecting the corrections above and any further corrections identified by other commenters.

Figure 2. Total HAP Metals From Oil-Fired EGUs



Total Metals does not include cobalt (Co).

Reevaluating the Proposed Standard

As discussed above, the Clean Energy Group recommends that EPA reevaluate its decision to include distillate oil-fired EGUs in the Utility MACT Rule. After reevaluating the risk assessment, if EPA confirms that it is "appropriate and necessary" to regulate distillate oil-fired EGUs under Section 112, the Clean Energy Group recommends that EPA recalculate the Total HAP Metals standard for oil-fired generating units based on all existing oil-fired EGUs, not simply the sources for which the Administrator has information (i.e., with the MACT floor calculated as the average of 12 percent of 154 units, or 19 units). This is consistent with the approach that EPA used in calculating the HCl and Total PM standards for coal-fired EGUs. We recommend this approach based on the fact that the ICR dataset is biased toward very low-emitting units, burning a distinctly different fuel type (distillate fuel oil). If EPA concludes that this is not a viable option, we recommend, at a minimum, that EPA subcategorize between residual- and distillate-oil fired EGUs. Each of these recommendations is discussed in turn.

As shown in Figure 2, the ICR data upon which the proposed limit is based includes six units burning distillate oil, all but one of which set the MACT floor. As a result, despite the disproportionate reliance on residual oil among the sector as a whole, five distillate oil-fired EGUs were included in the calculation of the MACT floor for Total HAP Metals. This includes one or multiple units from *all* distillate oil-fired EGUs in the U.S. Therefore, despite EPA's intention of selecting a random sample of units, in fact the ICR database is biased toward very low-emitting units, burning distillate fuel oil. Distillate oil-fired EGUs represent more than 70 percent of the units in the MACT floor used to calculate the proposed standard. In contrast, nationwide, distillate oil-fired EGUs represent less than five percent of oil-fired EGUs within the liquid oil subcategory. This results in a standard that is contrary to the statute, which directs the Administrator to establish standards that she "determines [are] achievable for new or existing sources in the category or subcategory to which such emission standard applies." In fact, nine units with ESPs and five units that were combusting a combination of natural gas and oil during ICR testing report emission rates above EPA's proposed standard for Total HAP Metals. Taken together with the fact that one distillate unit, Harding Street 10, tested essentially at the standard without a compliance margin, there is no clear path to compliance with the standard as proposed.

Another option that we ask EPA to consider would be to subcategorize between residual and distillate oil-fired EGUs. Residual and distillate oils are distinctly different fuels with different physical characteristics, heat content, and emissions profiles. Most of the fuel oil used in the electric power sector is residual fuel oil—a general classification for the heavier oils, including Grades No. 5 and No. 6, that remain after the distillate fuel oils and lighter hydrocarbons are distilled in the refining process. The lighter distillate fuel oils (No. 1 and No. 2) are characterized by lower viscosities and lower pour points. These grades of oil are used in most domestic burners and in many medium capacity commercial-industrial burners where ease of handling and ready availability justifies the higher fuel costs.

The formal classification of fuel oil grades is specified in ASTM Standard D396 - 10 (Standard Specification for Fuel Oils), providing a clear basis for subcategorizing the two fuel types. According to the standard, Grades No. 4 to No. 6 are generally residual fuels of increasing viscosity (resistance to flow) and boiling range. ASTM Standard D396 – 10 lists the viscosity of residual No. 5 and No. 6 fuel oils in the range of 5.0 to 50.0 square millimeters per second (mm^2/s) at 100°C. In contrast, ASTM Standard D396 – 10 lists the viscosity of distillate No. 1 and No. 2 fuel oils in the range of 1.3 to 4.1 mm^2/s at 40°C. We would also emphasize that the handling and use of residual and distillate fuel oils requires a different set of equipment and technologies. Residual fuel oils must be stored, shipped, and transferred in heated tanks, vessels, and heat traced piping. Further, in order to burn residual fuel oil, it is necessary to break the fuel into small droplets using steam atomization (200 pounds per square inch [psi] steam) or high pressure mechanical atomization (1,000 psi).

EPA lists 147 EGU boilers in the ICR database (Part I) that rely on residual fuel oil. EPA lists only seven EGU boilers that rely on distillate fuel oil: Harding Street (9 and 10), Eagle Valley (1 and 2), and Mitchell Generating Station (1, 2, and 3). Three of these units (Mitchell Generating Station Units 1-3) are listed for retirement in 2013. Eagle Valley Units 1 and 2 are listed for retirement in 2017. Other EGU boilers will burn limited quantities of distillate fuel oil for boiler light-off or other purposes, with fuel handling equipment separate from the residual oil equipment, while using another fuel, like natural gas, for the production of electricity.

Given the differences between residual and distillate fuel oils, we recommend that EPA consider subcategorizing between residual- and distillate-oil fired EGUs based on the ASTM specifications or the relative viscosities of the fuels—after considering the other options discussed above. Under this option, given that the total universe of distillate oil-fired EGUs would include less than 30 units, the Clean Air Act directs EPA to calculate the MACT floor based on a minimum of five units.

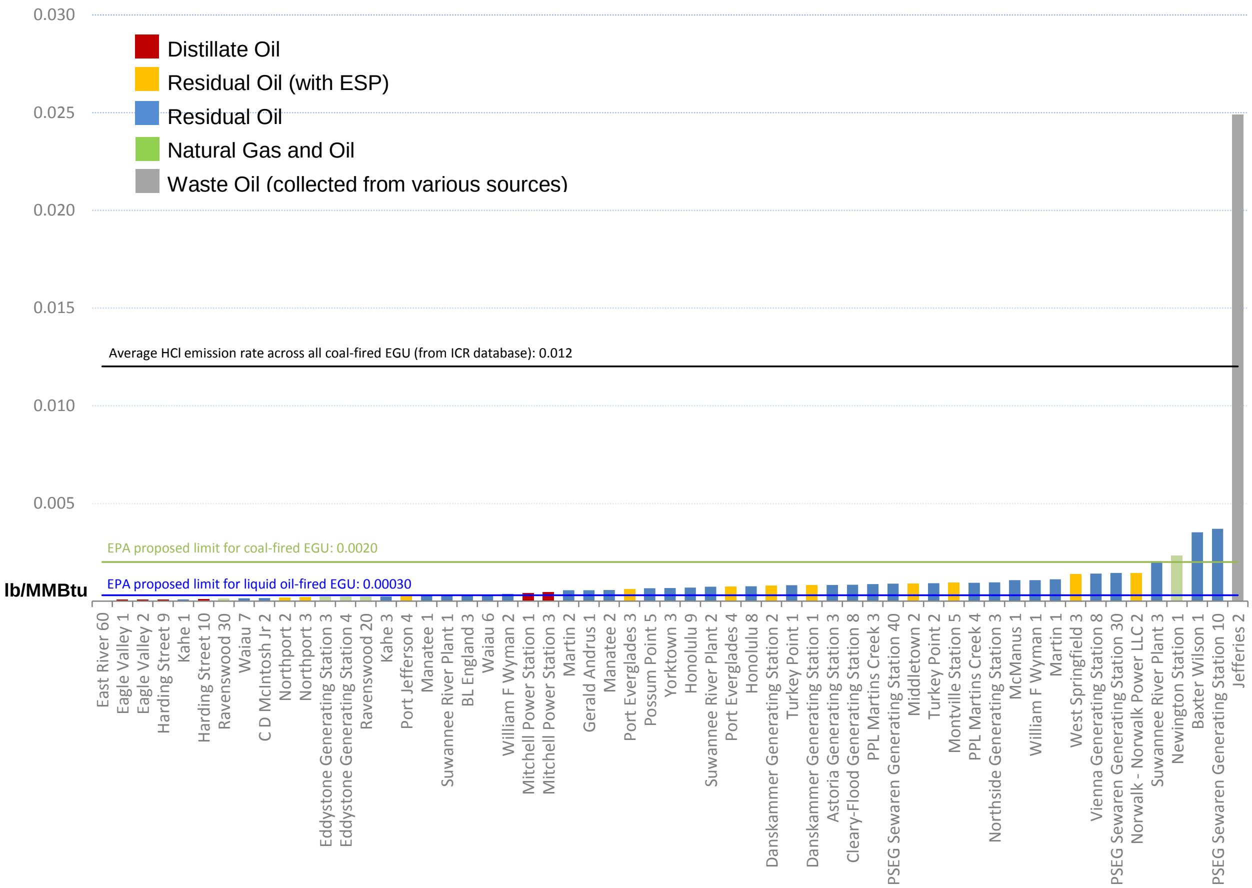
ii. Acid Gases

The EGU MACT rule proposes emissions limits for HCl and HF for liquid oil-fired EGUs. The standards for HCl and HF are proposed at 0.00030 lb/MMBtu and 0.00020 lb/MMBtu, respectively. The proposed standards for HCl and HF were calculated based on seven units.[16]

Figure 3 summarizes the HCl emissions data reported under the ICR. With the exception of Jefferies 2, which was burning waste oil during the ICR testing, all of the liquid oil-fired EGUs report low concentrations of HCl emissions. (EPA's proposed standard for existing coal-fired EGUs and the average HCl emission rate reported by coal-fired EGUs are provided for context.) Unlike the Total HAP Metals, there is no clear pattern in terms of the units meeting the proposed standard. There are units with ESPs, units combusting residual fuel oil, units combusting distillate fuel oil, and units co-firing natural gas both above and below the proposed limit for HCl. Also, we would emphasize that there are no installed or demonstrated control technologies for limiting HCl and HF emissions from liquid oil-fired EGUs, as there are for the other HAPs regulated under the proposed rule.

[16] The HCl standard was calculated based on East River 60, Eagle Valley 1 and 2 (distillate oil), Harding Street 9 and 10 (distillate oil), Kahe 1, and Waiau 7. The HF standard was calculated based on East River 60, Suwanee River 1 (distillate oil), CD McIntosh 2, BL England 3, Manatee 01, Northside 3, and Suwanee River 2 (distillate oil).

Figure 3. HCl from Oil-Fired EGUs



As further context, we calculated the potential annual emissions of HCl from the oil-fired EGUs that participated in the ICR. Virtually all units were found to emit HCl at levels below the major source threshold. Table 2 illustrates that the vast majority of the oil-fired boilers that participated in the ICR testing would emit HCl at levels well below the major source threshold of 10 tons per year for any individual HAP—particularly when we assume the low to intermediate utilization rates common among residual oil-fired boilers.

Table 2. Theoretical HCl Emissions Assuming Maximum Heat Input and a Range of Utilization Rates

Plant and Unit	Maximum heat input (mmBtu per hour)	Emissions (tons per year) assuming a range of utilization rates			
		100%	75%	50%	25%
East River 60	1,930	0.1	0.1	0.0	0.0
Eagle Valley 1	524	0.2	0.2	0.1	0.1
Eagle Valley 2	524	0.2	0.2	0.1	0.1
Harding Street 09	527	0.2	0.2	0.1	0.1
Kahe K1	903	0.4	0.3	0.2	0.1
Harding Street 10	527	0.3	0.2	0.1	0.1
Ravenswood 30	9,702	5.9	4.4	2.9	1.5
Waiau W7	922	0.6	0.4	0.3	0.1
C D McIntosh Jr Unit 2	1,185	0.8	0.6	0.4	0.2
Northport Unit2	3,650	3.0	2.3	1.5	0.8
Northport Unit3	3,650	3.5	2.6	1.7	0.9
Eddystone Generating Station Unit 3	4,546	4.5	3.4	2.3	1.1
Eddystone Generating Station Unit 4	4,546	4.5	3.4	2.3	1.1
Ravenswood 20	3,357	3.5	2.6	1.7	0.9
Kahe K3	892	0.9	0.7	0.5	0.2
Port Jefferson Unit4	1,850	2.0	1.5	1.0	0.5
Manatee PMT01	8,650	10.2	7.7	5.1	2.6
Suwannee River Plant Suw_Cfg_1	315	0.4	0.3	0.2	0.1
BL England 3	1,720	2.5	1.9	1.2	0.6
Waiau W6	637	0.9	0.7	0.5	0.2
William F Wyman 2	630	1.0	0.8	0.5	0.3
Mitchell Power Station 001	600	1.1	0.8	0.5	0.3
Mitchell Power Station 003	600	1.2	0.9	0.6	0.3
Martin PMR02	9,040	22.1	16.6	11.1	5.5
Gerald Andrus 001	6,650	16.4	12.3	8.2	4.1
Manatee PMT02	8,650	21.7	16.3	10.8	5.4
Port Everglades PPE03	4,000	10.6	8.0	5.3	2.7
Possum Point Unit 5	8,471	24.5	18.3	12.2	6.1
Yorktown Unit 3	8,883	26.2	19.6	13.1	6.5
Honolulu H9	632	1.9	1.4	1.0	0.5
Suwannee River Plant Suw_Cfg_2	353	1.1	0.9	0.6	0.3
Port Everglades PPE04	4,000	12.9	9.7	6.5	3.2
Honolulu H8	589	2.0	1.5	1.0	0.5
Danskammer Generating Station 2	650	2.3	1.7	1.1	0.6
Turkey Point PTF01	4,000	14.4	10.8	7.2	3.6
Danskammer Generating Station 1	650	2.3	1.8	1.2	0.6
Astoria Generating Station A-S0003	4,074	14.7	11.1	7.4	3.7
Cleary-Flood Generating Station 8	335	1.2	0.9	0.6	0.3
PPL Martins Creek U3	7,721	29.7	22.2	14.8	7.4
PSEG Sewaren Generating Station SEWU4E4PT4OS0	1,700	6.7	5.0	3.3	1.7
Middletown 2	1,173	4.7	3.5	2.3	1.2
Turkey Point PTF02	4,000	16.1	12.0	8.0	4.0
Montville Station 5	995	4.1	3.1	2.0	1.0
PPL Martins Creek U4	7,721	31.8	23.9	15.9	8.0
Northside Generating Station 3	4,857	20.6	15.4	10.3	5.1
McManus Unit 1	450	2.1	1.6	1.1	0.5
William F Wyman 1	630	3.0	2.2	1.5	0.7
Martin PMR01	9,040	44.3	33.3	22.2	11.1
West Springfield Unit 3	1,150	7.0	5.2	3.5	1.7
Vienna Generating Station Unit 8	2,317	14.4	10.8	7.2	3.6
PSEG Sewaren Generating Station SEWU3E3PT3OS0	1,600	10.1	7.6	5.1	2.5
Norwalk - Norwalk Power LLC 2	1,776	11.3	8.4	5.6	2.8
Suwannee River Plant Suw_Cfg_3	761	6.8	5.1	3.4	1.7
Newington Station nt1	4,350	44.4	33.3	22.2	11.1
Baxter Wilson 001	4,900	75.6	56.7	37.8	18.9
PSEG Sewaren Generating Station SEWU1E1PT1OS0	1,550	25.1	18.8	12.6	6.3

Notes:

1. Maximum heat input values and HCl emission rates are based on EPA's ICR database.
2. Values marked in green are greater than or equal to 10 tons per year. Values marked in yellow are less than 10 tons per year.

In reviewing the available literature and the ICR database, we found that chloride and fluoride concentrations in oil can vary widely. An Electric Power Research Institute (EPRI) analysis reported chloride values in No. 6 fuel oil ranging from 130 ppm to 715 ppm.[17] The units included in the MACT floor calculation for HCl reported significantly lower average chloride concentrations (see Table 3 below) during the test period, suggesting that the emission rates at these units could be higher with a different shipment of fuel. Baxter Wilson, for example, one of

[17] Maryland Power Plant Research Program. Hydrogen Chloride (HCl) Emissions from Maryland Utility Boilers. June 1999.

the higher emitting units in the ICR database, reports chloride concentrations in fuel ranging from 62 to 239 ppm. Most of the fluoride values (from fuel testing) reported in the ICR database are below the detection level. The wide variability in the chloride concentrations in fuel oil (combined with the lack of control technologies for limiting HCl emissions) suggests that EPA's variability adjustment may not result in a standard that would be achievable by the units that were included in the calculation of the MACT floor for liquid oil-fired EGUs.

Table 3. Chloride Concentrations in Fuel Oil from ICR Testing

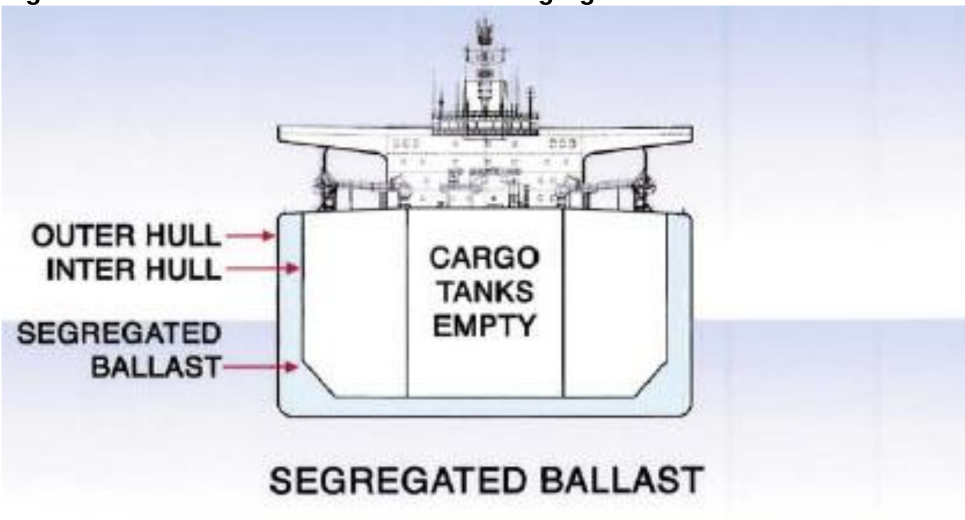
Unit	Chloride Dry
East River 60	20 ppm
Eagle Valley 1	<7.5 ppm
Eagle Valley 2	<7.5 ppm
Harding Street 9	37-38 ppm
Harding Street 10	37-38 ppm
Kahe 1	Below detection limit (less than 100 ppm)
Waiau 7	Below detection limit (less than 100 ppm)

Source: ICR Test Reports

Studies suggest that chloride in fuel oil can result from contamination during transportation and processing of crude oils.[18] For example, chloride contamination of crude oils can occur as a result of the ballasting of tanker ships with seawater.[19] Oil tankers load sea water as ballast for weight stabilization after a tanker has discharged its cargo. The ballast is required for safety reasons when the tanker is at sea. In older, single hull designs, seawater is loaded into the same cargo tanks that store the oil, resulting in seawater contamination when the cargo tank is reloaded. However, the Oil Pollution Act of 1990 requires all new oil tankers to be double-hulled (see Figure 4) and establishes a phase out schedule for existing single-hulled tankers with unsegregated ballasts. Ballast water contained in segregated ballast tanks never comes into contact with the cargo oil. Single-hulled tankers are scheduled to be phased out by the middle of this decade, reducing the potential for sea water contamination. Because of the role of sea water contamination in introducing contaminants into the oil, we suggest that EPA set a percent water content limit for fuel oil at a level of 1.0 percent, rather than setting HCl and HF emissions limits. This would encourage handling and transport practices to limit salt water contamination. We recommend a standard of 1.0 percent water because several of the lowest HCl and HF emitting units currently require percent water (or water and sediment) specifications between 0.5 percent and 1.0 percent.

[18] Ibid.
[19] Ibid.

Figure 4. Double Hulled Oil Tanker with Segregated Ballast



Source: Pacific L. A. Marine Terminal LLC

f. Compliance Requirements

i. Metals

Under the proposed rule, oil-fired units would be required to conduct monthly or bimonthly stack testing to demonstrate compliance with Total HAP metals, HCl, and HF. For the reasons introduced above, all stack testing requirements should be no more frequently than quarterly under standard operation (unless boiler operations or characteristics are substantially altered, in which case initial testing would be required to be repeated). We recommend that an oil-fired unit must run on a regulated fossil fuel (e.g., coal or oil) at least 168 hours in a calendar quarter to trigger stack testing requirements for all HAPs.

ii. Acid Gases

As discussed above, we recommend that EPA set a percent water content limit for oil, rather than setting HCl and HF emissions limits for liquid oil-fired EGUs. ASTM test methods are available for measuring the percent water content of fuel oil (D95 and D473). Plant operators would test each shipment received to ensure compliance with the proposed limit.

iii. Operating Limits

Similar to the above discussion on the compliance requirements for coal-fired EGUs, the Clean Energy Group has several concerns with the proposed parameter operating limits for oil-fired units and recommends an alternative approach that we think will better ensure proper operation of pollution control systems. Rather than establishing fixed operating limits, we recommend that EPA require proper operation of the plant's pollution control equipment and appropriate parametric monitoring without establishing numeric operating limits. Also, units with appropriate CAM plans and units operating CEMS should not be required to have additional monitoring requirements.

The Clean Energy Group looks forward to working with EPA on refining and implementing this important rulemaking. If you have any questions, please do not hesitate to contact me or Chris Van Atten at vanatten@mjbradley.com or (978) 369-5533.

Sincerely,

Michael Bradley
Director
The Clean Energy Group