UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

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Mr. Matthew Todd
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1220 L Street, NW
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Re: NSPS Ja Clarifications and Corrections

Dear Mr. Todd:

Thank you for your letter of November 30, 2012, regarding the New Source Performance Standards (NSPS) Subpart Ja amendments published on September 12, 2012 (77 Fed Reg. 56422). Your letter requested that we provide clarification through guidance or simple technical corrections on a number of issues of which you have requested reconsideration and/or clarification. Attached is a document that identifies the questions you provided in Attachment 1 of your letter and our responses.

Please contact Ms. Brenda Shine at (919) 541-3608 if you have any questions or would like to discuss these issues further.

Sincerely,

P Tsirigotis

Peter Tsirigotis
Director
Sector Policies and Programs Division

Attachment

Attachment 1
40 C.F.R. Part 60 Subpart Ja
API Questions and EPA Responses

Flares

API Question F1: Are open flame gas burners used as pilots, for heating equipment or other heating purposes considered flares under the new flare definition? With the removal of the "open-flame" criterion, are thermal oxidizers and other enclosed flame combustion devices now considered flares? Are air assisted flares excluded by the new flare definition?

EPA Response F1: Pilot flames are not considered flares. The changes to the definition of a "flare" were not intended to include thermal oxidizers, process heaters, or other truly enclosed combustion devices within the definition of a "flare," but were instead intended to include "enclosed" or shrouded flares within the definition. We revised the first sentence in the definition of a "flare" based on internal EPA and state agency comments regarding whether "enclosed" or shrouded flares were "flares" under the "open flame" definition because there is no visible open flame in these "enclosed" or shrouded flares. Our revision to the definition was meant to clarify that a "flare" does not have a contained combustion chamber and that "enclosed" or shrouded flares are considered "flares" because they have uncontrolled combustion air. We do not believe that this change significantly alters what is considered to be a "flare." Natural draft process heaters, boilers, and incinerators have combustion chambers and do not use "an uncontrolled volume of air." The air intakes for these devices have dampers that can effectively control the volume of combustion air entering the combustion chamber. On the other hand, "flares" with air assist still operate with uncontrolled volumes of combustion air. The "assist" air is used primarily to improve mixing. Further, we specifically include air injection systems as one of the components of a "flare," clearly indicating that air-assisted flares are "flares" under the amended definition of a "flare." We believe that, when one considers the full definition of a "flare," including the list of components of a "flare," the revised definition clearly distinguishes the types of combustion devices that are considered to be "flares" (including steam-assisted, air-assisted, or "shrouded" flares), and clearly excludes thermal incinerators, process heaters, or other devices that have completely enclosed combustion chambers.

API Question F2: By removing the "fuel gas combustion device" description from the definition of flares there is no longer a tie to the definition of fuel gas which specifically says that "Fuel gas does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units…" Did the EPA intend to no longer exclude from subpart Ja requirements:

- Flares that are used to comply with NSPS QQQ and/or NESHAP FF, or

- Flares that combust other gases that are not considered fuel gases under subpart Ja?

EPA Response F2: While we understand the concern you raise in this question, we are not providing an answer to this question in this guidance because a resolution of this issue will require amendments to the regulations. We will propose such amendments in a future rulemaking.

API Question F3: What constitutes an interconnected flare gas header system? Are temporary interconnects included? Must interconnecting piping be open to flow? Is there a size criterion for interconnections?

EPA Response F3: We are in the process of evaluating this question.

API Question F4: Is the reduced flare flow monitoring option in §60.103a(a)(3)(vi) available to flare combustion devices that are part of an interconnected flare system?

EPA Response F4: The alternative monitoring for certain flares described in §60.107a(g)[1] is available for any flare that meets the criteria specified in that paragraph, regardless of whether the flare is part of an interconnected flare gas header system or not. Therefore, we interpret the rule to allow the alternative monitoring option for individual flare tips (or individual combustors, as described by the commenters) in an interconnected flare system.

API Question F5: How do Root Cause Analysis/Corrective Action Analysis (RCA/CAA) triggers, monitoring and other subpart Ja flare requirements work for interconnected flare systems with multiple flare combustion devices? How do subpart Ja RCA/CAA requirements apply if an applicable Consent Decree contains more stringent triggers? Rule language is unclear if requirements apply to each flare combustion device or to the combination of combustion devices in an interconnected flare system. Similarly, where alternates are provided, what compliance deadlines apply to flare requirements?

EPA Response F5: We are in the process of evaluating this question.

API Question F6: What is required if an interconnection is added or removed and an existing independent flare system becomes part of an interconnected flare system or a previously interconnected flare becomes an independent flare system?

EPA Response F6: As we described in the response to comments in the preamble of the final subpart Ja amendments at 77 FR 56438, when a flare that is subject to NSPS subpart Ja is interconnected with a flare that is not subject to subpart Ja, the resulting interconnected flare is subject to NSPS subpart Ja and its requirements. When a previously interconnected flare becomes an independent flare system, and it was previously subject to NSPS subpart Ja, then each independent flare will be subject to NSPS subpart Ja, and such a change will likely require updating the flare management plan, per the requirements of 60.103a(b)(2), including updating the appropriate monitoring approach, and the method in which the source will comply with the RCA/CAA requirements (including revised baseline flows).

[1] The alternative flow monitoring option is described in §60.107a(g), not 60.103a(a)(3)(vi), as indicated in the question.

API Question F7: What is the status of a newly constructed flare that is interconnected with an existing flare?

EPA Response F7: As we explained in the preamble to the revisions to NSPS Subpart Ja, "when a flare that is subject to 40 CFR part 60, subpart Ja is interconnected with a flare that is not subject to subpart Ja, then the resulting interconnected flare is subject to subpart Ja." 77 Fed. Reg. 56422, 56438 (September 12, 2012). Thus, the interconnected flares would be subject to NSPS subpart Ja. If the existing flare was already subject to NSPS subpart Ja, the addition of the newly constructed flare would not impact the compliance deadlines for that flare.

API Question F8: §60.107a(e)(2) deals with developing the ratio of total sulfur to H_2S in flare gas, where only H_2S will be continuously monitored. Subparagraph (v) specifies the procedures for determining total sulfur in the daily samples collected to develop the ratio, but does not indicate what procedures are to be used to determine the H_2S concentration in these samples. What procedures must be used for determining H_2S in these samples?

EPA Response F8: The introductory paragraph in §60.107a(e)(2) requires the installation of monitors for continuously monitoring and recording the concentration of H_2S. These are the values that must be used to determine the ratio of total sulfur to H_2S. We are clarifying that the daily gas samples should be collected at approximately the same location as the location of the H_2S CEMS, and that the H_2S CEMS values used in the ratio are for the same time period as the sample collection, such that the composition of gas sampled is representative of the gas that is monitored using the CEMS. Further, we recognize that for flares equipped with flare gas recovery systems, gases burned in the flares during upsets or during other events when gases may overcome a flare gas recovery system may contain a significantly different composition and ratio of total sulfur to H_2S than gas burned in these flares when the flare gas is fully recovered. However, while NSPS subpart Ja does not require the owner or operator to account for these conditions in establishing the total sulfur to H_2S ratio, sampling of recovered gas to calculate the ratio using both the total sulfur and H_2S composition from the recovered gas is an acceptable approach.

API Question F9: §60.103a(a)(7) requires that the flare management plan include "procedures to minimize the frequency and duration of outages of the flare gas recovery (FGR) system and procedures to minimize the volume of gas flared during such outages." What types of outages are addressed by this provision?

EPA Response F9: The FMP should address all outage issues and should include procedures for minimizing their occurrence, duration and the volume of gas flared during such outages. Examples include, but are not limited to, outages that occur because of FGR system malfunctions, safety-related reasons (e.g., oxygen or liquid build-up at the flare gas compressor suction), and FGR system maintenance or FGR system improvements (e.g., upsizing equipment, installing sample or monitoring equipment).

API Question F10: Do the RCA/CAA flare flow and sulfur triggers apply during the FGR outages covered by the FMP procedures discussed in the previous question?

EPA Response F10: We are in the process of evaluating this question.

API Question F11: Paragraphs §60.107a(e)(4)(iii) and §60.107a(f)(2) provide for exceptions from continuous sulfur and flow monitoring, for "Flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction." Does "operated to capture <u>all</u> flows" [emphasis added] mean that the exceptions are not allowed if the FGR[2] must be shutdown for maintenance or safety reasons?

EPA Response F11: We are in the process of evaluating this question.

API Question F12: Paragraph §60.104a(j) specifies performance test methods for H_2S and was modified to indicate these methods apply to flares as well as fuel gas combustion devices. However, compliance with the flare H_2S requirements is demonstrated using the required H_2S CEMS or an approved alternative and §60.104a(a) specifies that performance tests are only required for emission limitations contained in §60.102a, which does not include the flare H_2S concentration limit, which is included in §60.103a. Is a performance test required for demonstrating compliance with the flare H_2S concentration limit?

EPA Response F12: We are in the process of evaluating this question.

API Question F13: §60.107a(f)(1)(ii) requires use of a flare flow sensor with a measurement sensitivity of no more than 5% of the flow rate or 10 cubic feet per minute (CFM), whichever is greater. It is unclear what "measurement sensitivity" means. Does this mean the vendor specified accuracy? Would a flow meter with a minimum flow velocity detection limit of 0.1 feet per second (fps) and 5% accuracy meet the requirements?

This is a concern for larger flare headers. For instance, for a 42" flare header, a 10 CFM change is only a 0.0173 fps change in velocity, which is the parameter typically measured. So the flow meter must be able to see a change of 0.0173 fps velocity when reading a flow of 200 CFM (288 MSCFD) or less. 200 CFM is 10 CFM divided by the required sensitivity of 5%. The typical flare gas flow meter will not meet this requirement at low velocities as it is only rated to measure 0.1 fps or greater velocities.

EPA Response F13: We are in the process of evaluating this question.

API Question F14: §60.107a(f)(1)(iv) requires at least quarterly visual inspections of all components of the required flare flow monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor. The required flare flow meter is a costly, highly specialized meter and it would never be justified to have a second identical meter. However, there will often be other flow meters that cover part of the flow range

[2] The original API correspondence contains a typographical error, referring to FGS instead of FGR.

or several meters that can be summed to provide a check on the required meter reading. Are such situations considered “redundant” meters for the purposes of §60.107a(f)(1)(iv)?

EPA Response F14: Any meter or collection of meters that can provide a continuous measure of the cumulative flow at the location of the required flare flow meter would qualify as a “redundant flow sensor” in §60.107a(f)(1)(iv). The purpose of the inspection requirement is to ensure that the flare flow measurements are not lost due to physical or operational integrity problems with the required flow monitor, particularly issues that could be avoided with appropriate preventive maintenance. If the flow measurement can be determined by summing the flow from a series of other meters, then the required flow measurement would not be lost if the primary flow meter signal is lost, and the quarterly inspections are not required.

API Question F15: §60.107a(f)(1)(iii) requires that the flare flow monitor be maintainable online. Since we know of no flow meters that can be maintained without losing data and that sometimes requires removal from the line in order to be maintained, we presume this requirement refers to the flare header remaining in service during maintenance. Is that correct?

EPA Response F15: This term means that the flow monitor may be maintained without having to take the flare piping out-of-service. For instance, use of an orifice plate flow meter that would require shutdown of the flare piping to maintain the orifice plate would not be “maintainable online,” but use of a sonic sensor that could be removed from the flare piping for maintenance while that piping remains in service would be “maintainable online.”

API Question F16: §60.107a(f)(1)(iii) also requires that the flow monitor should "be able to record flow in standard conditions ... over one-minute averages." Though technically possible, there are practical constraints to recording one minute averages. Even though a digital control system could capture flow readings much more frequently than once per minute, trying to get these higher-frequency readings into the recordkeeping system at that rate has the potential to bog down the historian system, leading to possible operational difficulties with proper control of the other processes being tracked by the system. A once per minute record is possible, but it is unclear whether a once per minute sample would qualify as a "one-minute average" for purposes of the rule.

EPA Response F16: The requirement in §60.107a(f)(1)(iii) is intended to require that the flow meter be capable of outputting the volumetric flow rate each minute. Therefore, a “once per minute” reading would qualify as "one-minute averages" for purposes of the rule.

API Question F17: The amendments add technical requirements for flare water seal instrumentation where allowed as an alternative to flare gas flow monitoring. §60.107a(g)(3) specifies that such a flare seal must "use a pressure sensor and level monitor with a minimum tolerance of 1.27 cm of water." The apparent requirement that the pressure instrument have a tolerance of at least 1.27 cm of water may be technically infeasible. This tolerance level is within the noise level for a typical pressure sensor used in such an application. Thus, we assume the 1.27 cm of water minimum tolerance only applies to the level monitor, for which this minimum tolerance would be typically achievable. Is this correct?

EPA Response F17: While we understand the concern you raise in this question, we are not providing an answer to this question in this guidance because a resolution of this issue will require amendments to the regulations. We will propose such amendments in a future rulemaking.

API Question F18: §60.108a(c)(6) and (d)(5) specify that each time the pressure in the flare line exceeds the water seal backpressure an event is counted. After 4 events, the reduced monitoring option is no longer available. Any single process event will usually cause multiple exceedances using that definition, since flare header pressure swings, events often cause intermittent or cyclic releases to the flare. Furthermore, releases to the flare due to a single event may come from many individual points and attempts at controlling releases often result in intermittent releases. Thus, using a conservative interpretation of this definition makes the 4 event limit meaningless. Are multiple exceedances that are due to a single process event counted as separate events for the purpose of the 4 event limit?

EPA Response F18: It was not our intent to count multiple exceedances related to a single process event multiple times in determining if a flare experienced four or fewer "reportable pressure exceedances" (§60.107a(g)(7)) and could qualify for using the reduced monitoring option. Owners and operators likely would not be able to anticipate how many multiple short-term pressure exceedances could occur as a result of a single process event in determining whether they could avail themselves of the reduced monitoring option. Therefore, multiple occurrences where the flare line pressure exceeds the water seal pressure would count as a single event if it is clearly demonstrated and recorded that the occurrences were all the result of the same process event. This is consistent with the provision in 60.103a(d)(5) that allows an owner or operator to conduct a single root cause and corrective action analysis if the owner or operator determines that multiple discharges have the same root cause.

API Question F19: Can refineries located in the SCAQMD or BAAQMD regions of California opt to use TRS CEMS to demonstrate compliance with the H_2S limit as allowed by §60.107a(a)(2)(v)?

EPA Response F19: As provided in §60.107a(h), complying with SCAQMD or BAAQMD requirements instead of §60.107a(e) and (f) is an alternative way for flares located in those districts to comply with the RCA/CAA sulfur requirements in subpart Ja. Use of that option for that purpose does not impact the sources choices as to how to comply with the H_2S monitoring requirements in §60.103a(h), including the option to use a TRS analyzer as allowed by §60.107a(a)(2)(v). However, §60.107a(a)(2)(v) specifically states that "[t]he owner or operator of a flare subject to § 60.103a(c) through (e) may use the instrument required in paragraph (e)(1) of this section to demonstrate compliance with the H_2S concentration requirement in § 60.103a(h) if the owner or operator complies with the requirements of paragraph (e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in paragraph (e)(1) of this section is used to demonstrate compliance with the H_2S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in § 60.103a(h)." When providing the alternative to comply with the SCAQMD or BAAQMD requirements instead of the flare management work practice standards in §60.103a(a) through (e), and corresponding monitoring in §60.107a(e) and (f), we evaluated the effectiveness of the requirements as a whole, and not each specific requirement in subpart Ja. We did not specifically determine that the monitoring requirements within SCAQMD or BAAQMD rules were specifically equivalent to requirements of paragraph (e)(1)(i) through (iii) [note: there is no paragraph (e)(1)(iv); this will be amended]. While a SCAQMD or BAAQMD flares may have sulfur monitors, unless those monitors also meet the requirements in §60.107a(e)(1)(i) through (iii), these flares cannot use the alternative in §60.107a(a)(2)(v).

Process Heaters

API Question PH1: May performance evaluations of fuel gas and fuel oil flow monitors, required when complying with the NOx mass emission limits and for smaller process heaters using the biennial stack test option, that also are used to control process heater firing be delayed until the monitor can be taken out of service without shutting down the process heater and associated process?

EPA Response PH1: The mass emission limits in §60.102a(g)(2)(iii)(B) and (iv)(B) are alternatives to concentration limits in §60.102a(g)(2)(iii)(A) and (iv)(A). One cannot elect to comply with the mass emission limits in §60.102a(g)(2)(iii)(B) and (iv)(B) unless they have the requisite monitors to accurately assess the mass emissions (i.e., the performance of the monitors are properly verified). Therefore, the process heater must either meet the concentration limits provided in §60.102a(g)(2)(iii)(A) and (iv)(A) or request an alternative emission limit under §60.102a(i) until such time as the performance of the flow monitors can be verified.

API Question PH2: May existing O_2 monitors be used to meet the O_2 monitoring requirements on small process heaters where the biennial performance test compliance option is used?

EPA Response PH2: Under § 60.107a(c)(6), an owner or operator of a process heater equipped with combustion modification-based technology (low-NOx burners or ultra-low NOx burners) with a rated heating capacity between 40 and 100 MMBTU/hr, can either conduct biennial source testing or use a NOx CEMS. If using biennial source testing, you are required to establish a maximum excess O_2 concentration operating limit or operating curve that can be met at all times and comply with the O_2 monitoring requirements for the ongoing compliance demonstration(see §60.107a(c)(6)). While we anticipate that most process heaters would use their existing O_2 monitors, rather than installing new O_2 CEMS, it is important that the O_2 monitor meet minimum quality assurance and performance requirements so compliance with the operating limit can be accurately determined.

Delayed Cokers

API Question D1: With the expansion of the delayed coker affected facility to the coke drum cutting water and quench system, process piping and associated equipment such as pumps, valves and connectors and the coke drum blowdown recovery compressor system, it appears that even minor changes (e.g., adding a few valves and connectors for a new sample point or pressure gauge) would be considered a modification and would require immediate compliance with the coke drum vent control requirements in subpart Ja. The failure to provide the needed compliance time and to identify in the rulemaking record that all delayed cokers would quickly become subject, suggests it was not intended that such small, unrelated changes trigger the rule. Is that correct?

EPA Response D1: We are in the process of evaluating this question.

API Question D2: What is the compliance deadline for DCUs that were modified between May 14, 2007 and September 12, 2012? Also, does the compliance clock restart if a DCU that was modified between May 14, 2007 and September 12, 2012 is modified again after September 12, 2012?

EPA Response D2: Per §60.14(g), compliance is required within 180 days of completing the modification. A facility should consult §60.100a(b) for the applicable definition of DCU when determining whether the DCU was "modified" and whether it triggered applicability of NSPS subpart Ja. No, the compliance clock does not restart if another project conducted after September 12, 2012 also qualifies as a "modification" of the DCU. Once an existing DCU becomes subject to NSPS subpart Ja, future changes to that DCU do not impact the compliance requirements or schedule for compliance.

Fuel Gas and Fuel Gas Combustion Devices (FGCD)

API Question FG1: §60.102a(g)(iii) states "The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii)." Thus, the sulfur limits for combustion of fuel gas do not apply to portable generators combusting gas from tank degassing and/or cleaning. "Portable generator" is not defined, however, and is an entirely new term and the explanation for this exception in Section 2.1 of the Response to Comments is unclear whether thermal incinerators are considered portable generators. For these short term control situations, portable engines, thermal oxidizers and flares are typically used, depending on availability, gas composition, utility availability and other factors. Are all of these portable, temporary use devices considered "portable generators" for the purposes of this paragraph?

EPA Response FG1: We are in the process of evaluating this question.

API Question FG2: §60.107a(i)(1)(ii) appears to identify periods of excess emissions for the fuel gas H_2S concentration limit on a per FGCD basis. Even though many FGCDs receive fuel from the same mixing drum, which is where the H_2S CEMS is usually located, the individual FGCD averages will be different, because of differences in the operating hours among the FGCDs. Can individual FGCD operating hours be ignored in calculating fuel gas H_2S averages for the purpose of identifying periods of excess emissions?

EPA Response FG2: As most refinery process units operate continuously, we anticipated that hours where gas flow was present at the monitoring location would be equivalent to the operating hours of the FGCD. We do recognize that, when using a centralized monitoring location, which the Refinery NSPS subpart Ja specifically allows, there may be times that some (but not all) FGCDs may be off-line. We intended that the periods of excess emissions would be determined based on the general operating conditions at the CEMS location. The period of excess emissions would be reported based on the CEMS monitoring data and all FGCDs subject to subpart Ja that were operational during that period would be identified. That is, the excess emissions report would need to list each FGCD that was operational during any portion of the excess emissions event as monitored at the centralized location. FGCD that were not operational during any portion of the excess emissions event would not need to be listed for that excess emissions event.

Sulfur Recovery Plants (SRPs)

API Question S1: The definition of SRP states that "Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. Sulfur recovery plants that receive source gas from completely segregated sour gas treatment systems are separate affected facilities." [emphasis added] It is not uncommon that a SRP will normally receive source gas from a completely segregated sour gas system, but occasionally receive sour gas from another source, when maintenance outages or operating problems at another SRP would require large refinery production cutbacks otherwise. Does that make these two SRPs one affected facility?

EPA Response S1: As noted in the Response to Comment (RTC) document ("Standards of Performance for Petroleum Refineries – Background Information for Final Standards"; U.S. EPA, April 2008),"[i]f the SRU [sulfur recovery unit] receive sour gas from completely segregated sour gas treatment systems and there is no connection between the SRU, than the SRU are considered to be part of separate SRP. If there is a connection between SRU such that sour gas could be transferred from one to the other, these SRU are considered one SRP." In the case described above, there appears to be connections between these SRU, even if they are used only occasionally, so that these SRU would be one SRP and one affected facility under NSPS subpart Ja.

Other

API Question O1: In the Response to Comments document for the final amendments (First Item, Section 6.1, page 117) it is indicated that a continuous monitoring system outside the certified span is "out-of-control" and therefore invalid, but then indicates that sources are required to use that invalid data in determining compliance averages. This position is directly opposite to the position stated in the next response to comment and in 4.3.1 and 4.3.2 of Appendix F of part 60 which applies to subpart Ja CEMS, where "out of control" is defined as only relative to failure to meet the daily calibration drift check and prohibits use of out-of-control data in calculating compliance averages. Does EPA intend to override its promulgated and historical position as to what constitutes "out-of-control" and how such data is to be used?

EPA Response O1: It is not our intent to change the definition of "out-of-control" in Appendix F of part 60, which is specifically limited to failure to meet daily calibration checks or audit accuracy requirements. In our second response in the RTC (the second response in Section 6.1, pp 117-118), we were directly responding to the question of how to deal with periods of "out of control according to Appendix F." In that second response, we explained the following: "CMS out of control periods [as defined in Appendix F] would be considered null values for the purposes of calculating the 30-day or 365-day average." Thus, for periods when the CMS fails the daily calibration checks or has excessive audit inaccuracies, those periods should not be used in determining compliance averages. However, it makes no sense to discard periods when the CMS is working accurately, but the concentrations are so high that they exceed the calibrated span of the monitor. Such a provision would reward facilities with large concentration excursions and allow them to be potentially compliant by excluding their largest exceedances as null values. In our first response in the RTC (the first response in Section 6.1, pg 117), we indicated that our typical policy in these large exceedances is to deem the affected facility to be out of compliance (i.e., "to declare their compliance as other than continuous"). However, when considering the long-term averages in Subpart Ja, we considered that reporting 365 days of non-compliance with a 365-day average due to one exceedance of the calibrated span to be counter-productive. Therefore, we stated the following in the first response: "for the purposes of calculating rolling averages, the direct monitor reading should be used for all periods that the CMS is operational, except for periods when the CMS data are invalidated according to 40 CFR 60.13(h)(2)(iv)." We note that the "periods when the CMS data are invalidated according to 40 CFR 60.13(h)(2)(iv)" are the out-of-control periods as defined in Appendix F, which does not consider the concentrations seen by the monitor during normal operation. We agree that it was confusing to refer to the CEMS as "out of control" in our first response since it is really the emission control system that is "out of control" and not a period that is "out of control as defined in Appendix F." Thus, while we acknowledge the confusion those RTC responses may have created, we provide the following clarifying explanation here regarding this issue. For periods when the concentration of the gases being monitored exceeds the CMS calibrated span, but is within the instrument range, the direct reading from the CMS (rather than the maximum calibrated span value or a null value) should be used when calculating the long-term averages. For periods when the concentration of gases monitored exceeds the instrument range, the instrument range value should be used when calculating the long-term averages. We see this as a much more reasoned approach than either ignoring the high concentration event altogether in the long-term average calculation or requiring facilities to report all averaging periods that include the span exceedance period as an exceedance of the applicable emission limit.

API Question O2: Corrective Action Analysis is defined in §60.101a as "a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety and secondary impacts." This definition would not appear to allow a conclusion that none of the identified corrective actions are justified and thus would appear to require implementation of the “best alternative(s)”, even if it is not justified by the costs, safety and feasibility concerns or secondary impacts. Is that a correct interpretation of the definition?

EPA Response O2: As specifically provided for in §60.103a(e)(1), an owner or operator can conclude that no corrective action is required. In such a case, “the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in §60.108a(c)(6)(ix).”