RECENT NSPS REGULATION CHANGES AFFECTING THE OIL AND GAS INDUSTRY

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INTRODUCTION

This paper intends to provide an overview of the recent changes in NSPS regulations that affect the oil and gas industry. Specific instances for new or modified facilities that are not covered here should be referred to a specific consultant or state agency for consultation. It also should be noted that these regulations are not comprehensive in nature and additional requirements for the facilities may be applicable, such as NESHAP, MACT, etc. This paper also does not cover the general provisions in 40 CFR 60. Specific notification and reporting requirements are listed in the general provisions that are required of any facility that is affected by any subpart of 40 CFR 60.

The changes in these regulations were intended to reduce VOC emissions from sources at oil and gas facilities. It is intended that only the changes in the regulations that have been made between August 2012 and February 2013 will be highlighted in this paper. The specific subparts that are addressed in the paper are:

- Subpart OOOO: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution
- Subpart JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
- Subpart IIII: Standards of Performance for Compression Ignition Internal Combustion Engines
- Subpart LLL: Standards of Performance for SO_2 Emissions from Onshore Natural Gas Processing Plants For Which Construction, Reconstruction, Or Modification Commenced After January 20, 1984 And On Or Before August 23, 2011
- Subpart KKK: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for which Construction, Reconstruction, or Modification Commenced After January 20, 1984 and on or Before August 23, 2011
- Subpart Ja: Standards of Performance for Petroleum Refineries for which Construction, Reconstruction or Modification Commenced After May 14, 2007
- Subpart J: Standards of Performance for Petroleum Refineries

There has been talk that EPA may be coming out with some clarifications to Subpart OOOO in March 2013 to be effective July 2013. Those changes are not reflected in this paper, since they were not available at the time of writing. An updated version of this paper can be obtained electronically from the author that would reflect those changes and clarifications.

This paper does not include detailed information on the performance test methods and procedures, since these are typically performed by third-party laboratories. Likewise, design analysis requirements are not included here since the equipment design is typically performed by a third-party engineering or supply firm. It has been noted though in the paper when there are specific test or design requirements for the regulation, as it is important to ensure that the third-party is aware of these requirements, as well.

While the regulations noted here are federal, the paper will at times reference various Texas state agencies. If the facilities are not within the state of Texas, then the applicable state agency should be consulted.

For the sake of brevity and clarification, certain terms in the regulations have been simplified. These words and phrases are noted here. The term "operator" refers to any time that the regulation uses the term "owner and/or operator". The term "approved test methods and procedures" refers to the test methods and procedures dictated by certain provisions that are contained in 40 CFR 60 appendices; these are commonly ASTM or other approved methods to ensure accurate data collection. The term "installation" or "construction" refers to not only new installation or construction, but also reconstruction or modification of a facility.

SUBPART OOOO: STANDARDS OF PERFORMANCE FOR CRUDE OIL AND NATURAL GAS PRODUCTION, TRANSMISSION AND DISTRIBUTION

This subpart intends to reduce VOC and SO_2 emissions from crude oil and natural gas facilities. It affects facilities that commenced construction, modification, or reconstruction after August 23, 2011. Facilities that commenced construction prior to this date are NOT subject to this subpart unless they are modified or reconstructed. Most affected facilities must be in compliance with this subpart by October 15, 2012 or upon startup. Pneumatic controllers and storage tanks must be in compliance by October 15, 2013. It should be noted that this subpart was backdated to include facilities that began construction more than one year before the regulation was published. This resulted in some facilities having essentially one month or less to comply with the standards in this regulation.

Natural Gas Well

The first facility that will be examined is the natural gas well. A gas well or natural gas well means an onshore well drilled principally for production of natural gas. If there is doubt as to whether the well is considered a natural gas well, then it would be recommended to get a determination from the state oil and gas agency. For each well completion operation with hydraulic fracturing, the regulation requires that gas and liquids be recovered by routing them to a storage vessel, re-injecting them into a well, or using the gas for another meaningful purpose, such as an on-site fuel source. There should not be any release to the atmosphere. All salable gas must be routed to the gas flow line as soon as practicable. If neither of these are feasible, then the flowback emissions must be captured and directed to a completion combustion device. EPA has now determined that operators have a general duty to safely maximize recovery and minimize releases to the atmosphere during flowback and subsequent recovery. The only exception to this provision is where a completion combustion device may result in a fire hazard or explosion or where high heat emissions may negatively impact tundra, permafrost, or waterways.

For each well completion with hydraulic fracturing that meets the criteria for a wildcat or delineation well or a non-wildcat low pressure gas well or non-delineation low pressure gas well, it is only required that flowback emissions must be captured and directed to a completion combustion device and that operators have a general duty to safely maximize recovery and minimize releases to the atmosphere during flowback and subsequent recovery. The notification and reporting requirements must also be met on these wells.

Hydraulically refractured gas wells are not considered an affected facility, if they meet the conditions above. If it does not meet the conditions above, then the regulation considers it a modification to a gas well and it becomes subject to the requirements. Refracturing a gas well does not make the other equipment at the well site subject to any other requirements. The gas well is considered a standalone facility for the purposes of this subpart. It is also important to note that EPA backdated this regulation and made any source initially constructed after August 23, 2011 an affected source that must be in compliance by October 15, 2012 or on startup.

For each well completion with hydraulic fracturing begun prior to January 1, 2015, it is only required that flowback emissions must be captured and directed to a completion combustion device and that operators have a general duty to safely maximize recovery and minimize releases to the atmosphere during flowback and subsequent recovery. For well completions with hydraulic fracturing begun on or after January 1, 2015, all four requirements noted for gas wells will be applicable.

It is vital to note that notification must be made to the state no later than two days prior to starting each well completion. TCEQ has greatly simplified this process for facilities within the state of Texas and has developed a PDF form that can be completed and e-mailed to NSPSWell@tceq.texas.gov. An automatic e-mail response will confirm the agency received the form and will provide a copy of the submitted form for recordkeeping. A company can also log into STEERS and submit notification electronically. Once the submission is accepted, notification is complete. Additional information can be found at www.TexasOilandGasHelp.org.

Each operator must maintain a log for each well. It must be completed on a daily basis and includes things such as a digital photo of the location, duration of flowback, combustion, and venting. It must also contain the information included in the notification. This log is then used to submit an initial report and prove compliance with the regulation. The initial report is due 30 days after the initial compliance period. Subsequent annual reports are due on the same date. The regulation does allow an operator to align other reporting requirements, such as Title V reporting, as long as the period is not any longer than one year. Records must be maintained for five years. All reports must be certified by a responsible official.

Centrifugal Compressor

The next facility that will be examined is the centrifugal compressor. If a centrifugal compressor that uses wet seals is located between the wellhead and the point of custody transfer, then VOC emissions from each wet seal fluid degassing system must be reduced by at least 95%. Compliance must be achieved by October 15, 2012 or on startup.

If a control device is used to reduce emissions, then a cover must be installed, as well as a closed vent system. There are specific requirements as to the design and operation for the cover and closed vent system to prevent VOC emissions. Compliance demonstrations on the control device must use approved test methods and procedures. The regulation considers the following units as control devices: thermal vapor incinerators, catalytic vapor incinerators, boilers, process heaters, carbon adsorption systems, condensers, other non-destructive vapor recovery devices, other non-destructive control devices, and flares. Control devices must be in operation at all times.

An initial performance test is required within 180 days of initial startup or October 15, 2012, whichever is later. Initial inspections of each closed vent system or cover are required. The closed vent system must demonstrate that it operates with no detectable emissions using approved test methods and procedures. Notification of construction, initial startup and modification must be submitted in accordance with 40 CFR 60.7(a). Annual visual inspections must be conducted for defects that could result in air emissions. The initial report is due 30 days after the initial compliance period. Subsequent annual reports are due on the same date. The regulation does allow an operator to align other reporting requirements, such as Title V reporting, as long as the period is not any longer than one year. Records must be maintained for five years. All reports must be certified by a responsible official.

Reciprocating Compressor

The next facility that will be examined is the reciprocating compressor located between the wellhead and the point of custody transfer. A reciprocating compressor located at a well site or at an adjacent well site that services multiple well sites is not an affected facility. The rod packing must be replaced prior to 36 months or before the compressor has operated 26,000 hours since the last rod packing or since initial startup. The number of hours of operation must be continuously monitored or the number of months since the last rod packing must be tracked beginning on initial startup or October 15, 2012.

The initial report is due 30 days after the initial compliance period. Subsequent annual reports are due on the same date. The regulation does allow an operator to align other reporting requirements, such as Title V reporting, as long as the period is not any longer than one year. Notification of construction, initial startup and modification must be submitted in accordance with 40 CFR 60.7(a). Records must be maintained. All reports must be certified by a responsible official.

Pneumatic Controllers

The next facilities that we will examine are continuous bleed natural-gas driven pneumatic controllers that operate at a natural gas bleed rate greater than 6 SCF/hr. The affected controllers are located either between the wellhead and point of custody transfer for the oil or natural gas production segment or are located at a natural gas processing plant. Controllers located between the wellhead and the point of custody transfer must have a bleed rate less than 6 SCF/hr. Controllers at a natural gas processing plant must have a bleed rate of zero. These controllers must be tagged with the month and year of installation and identification information that allows traceability to the records for that pneumatic controller. Facilities at gas plants must be in compliance by October 15, 2012, or on startup, whichever is later. Facilities between the wellhead and the plant must be in compliance by October 15, 2013.

If a continuous bleed natural gas-driven pneumatic controller with a bleed rate greater than 6 SCF/hr is needed for functional or safety reasons, then the reasons why must be documented. This documentation must be maintained as part of the records for the life of the pneumatic controller and must be in all reports.

The initial report is due 30 days after the initial compliance period. Subsequent annual reports are due on the same date. The regulation does allow an operator to align other reporting requirements, such as Title V reporting, as long as the period is not any longer than one year. Records must be maintained. All reports must be certified by a responsible official.

Storage Vessels

The next facility that will be examined is the storage vessel located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. This provision requires an operator to determine the emissions from each tank constructed, modified or reconstructed after August 23, 2011. The regulations do not limit this requirement to only oil/condensate storage vessels; produced water tanks, methanol tanks, chemical totes, etc are covered by the regulation. If the VOC emissions are determined to be greater than 6 TPY, then VOC emissions must be reduced by at least 95%. For new tanks at a new well site, VOC emissions must be determined within 30 days of startup and reduced by 95% if required within the next 30 days (total of 60 days from startup). For new tanks at sites already in operations (includes compressor stations and gas plants), VOC emissions must be calculated and reduced by 95% upon startup. No specific calculation methodology is specified. It is recommended that the TCEQ spreadsheet available for oil and gas facilities be used to tabulate emissions for storage tanks. The spreadsheet allows various methods (TANKS, Direct Measurement, GOR, etc.) to be entered. The tanks can be linked to a flare device and emissions calculated with approved AP-42 factors. Facilities must be in compliance by October 15, 2013, or on startup, whichever is later.

If the storage vessels are subject to and controlled in accordance with 40 CFR 60, Subpart Kb or 40 CFR 63, Subparts G, CC, HH, WW, or HHH, then they are not subject to this subpart.

If a control device is used to reduce emissions, then a cover must be installed, as well as a closed vent system. There are specific requirements as to the design and operation for the cover and closed vent system to prevent VOC emissions. Compliance demonstrations on the control device must use approved test methods and procedures. The regulation considers the following units as control devices: thermal vapor incinerators, catalytic vapor incinerators, boilers, process heaters, carbon adsorption systems, condensers, other non-destructive vapor recovery devices, other non-destructive control devices, and flares. Control devices must be in operation at all times.

If a floating roof is used to reduce emissions, then the requirements of Subpart Kb become applicable. A vapor recovery system is required based on the true vapor pressure of the liquid stored. Initial inspections are required, as well as an annual visual inspection. Seal gap measurements must be taken for external floating roof tanks.

To demonstrate compliance, conduct an initial performance test within 180 days after initial startup or within 180 days of October 15, 2013, whichever is later. Conduct a compliance demonstration on the vessels and the initial inspections. A continuous parameter monitoring system must be installed and operated on the vessels.

The initial report is due 30 days after the initial compliance period. Subsequent annual reports are due on the same date. The regulation does allow an operator to align other reporting requirements, such as Title V reporting, as long as the period is not any longer than one year. Records must be maintained. All reports must be certified by a responsible official.

Onshore Natural Gas Processing Facility

The next facility that will be examined is equipment within a process unit at an onshore natural gas processing facility, except compressors. This provision applies to new equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit, if it is located at an onshore natural gas processing plant. Each piece of equipment is assumed to be in VOC service or in wet gas service unless demonstrated otherwise. VOC service is defined as a stream having greater than 10% by weight of VOCs. Wet gas service is defined as field gas that has not undergone any extraction processes. Facilities must be in compliance by October 15, 2012, or on startup, whichever is later. Notification of construction, initial startup and modification must be submitted in accordance with 40 CFR 60.7(a).

Equipment not located at the onshore natural gas processing plant is exempt from these requirements. Equipment within a process unit located at an onshore natural gas processing plant is exempt if the equipment is subject to any LDAR requirements (40 CFR 60 Subparts VVa, GGG, GGGa). Addition or replacement of equipment for process improvement without a capital expenditure is not considered a modification. For example, if an engine at Site A is replaced by a similar engine from Site B, then the requirements will not be triggered. There are also some design standards on certain process equipment that may exempt that equipment from these requirements as well.

Equipment must be monitored for leaks on the required schedules. Monitoring frequency and leak definitions vary based on the type of equipment. If the equipment is found to be leaking, then a weatherproof and readily visible tag must be attached to the leaking equipment. The leak must be repaired within certain timeframes depending on the equipment. Tag removal requirements depend on the equipment. Records of repair attempts and dates must be kept. All records must be kept for five years. Semiannual reports detailing the information about leaks and monitoring recorded during the reporting period are due every 6 months after the initial startup date.

Sweetening Unit Located At A Natural Gas Processing Plant

The next facility that will be examined is a sweetening unit located at a natural gas processing plant. Facilities that have a design capacity less than 2 LTPD of H_2S in the acid gas only have to comply with the recordkeeping and reporting requirements specified. Sweetening facilities producing acid gas that is completely reinjected into an oil-or-gas-bearing geologic strata or that is not released to the atmosphere do not require the compliance tests required in this subpart. Facilities must be in compliance by October 15, 2012, or on startup, whichever is later. Notification of construction, initial startup and modification must be submitted in accordance with 40 CFR 60.7(a).

During the initial performance test, a minimum SO_2 emission reduction efficiency must be achieved based on factors provided in the tables of the regulation. The Tutwiler procedure, which is provided in the regulation, or a chromatographic procedure must be used to determine the H_2S concentration in the acid gas. The accumulation of sulfur and H_2S concentration in the acid gas must be monitored for each 24 hour period. A monitoring device must be installed that measures the flow rate of acid gas from the sweetening unit.

A continuous monitoring system must be installed and operated. Specifics of the monitoring system requirements depend on the control system chosen for to reduce sulfur dioxide emissions. The average sulfur emission reduction efficiency must be calculated for each 24-hour period. Special requirements that allow alternate compliance demonstrations exist for facilities with a design capacity less than 150 LTPD of H_2S expressed as sulfur.

Records of calculations and measurements must be kept for two years. Annual reports of excess emissions must be submitted. Excess emissions are defined as any 24-hour period where the average sulfur emission reduction efficiency is less than the minimum required efficiency or (if applicable) any 24-hour period where the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature. If applicable, a record demonstrating that the facility's design capacity is less than 150 LTPD of H_2S expressed as sulfur.

The initial report is due 30 days after the initial compliance period. Subsequent annual reports are due on the same date. The regulation does allow an operator to align other reporting requirements, such as Title V reporting, as long as the period is not any longer than one year. Records must be maintained. All reports must be certified by a responsible official.

SUBPART JJJJ: STANDARDS OF PERFORMANCE FOR STATIONARY SPARK IGNITION INTERNAL COMBUSTION ENGINES

This subpart seeks to reduce emissions from stationary spark ignition (SI) internal combustion engines (ICE). This paper will not examine the requirements for manufacturers of stationary spark ignition internal combustion engines; it will only examine the requirements for owners and/or operators of stationary spark ignition internal combustion engines. A navigation flowchart from TCEQ is available on their website that can help determine whether this subpart is applicable or not and the specific set of standards, recordkeeping and reporting requirements.

This subpart is applicable to: operators of SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: on or after July 1, 2007 for 500 hp to 1350 hp engines; on or after January 1, 2008 for 500 hp to 1350 hp lean burn engines; on or after July 1, 2008 for engines less than 500 hp; and on or after January 1, 2009 for emergency engines greater than 25 hp. Stationary SI ICE using alcohol-based fuels are considered gasoline engines

Stationary SI ICE being tested at a stationary SI ICE test cell/stand are excluded from this subpart. Temporary replacement units located at the site less than one year and that have been certified to meet the standards may be exempt from the other requirements of this provision.

Emission standards are established based on the engine model year, maximum engine power, and whether the engine rich burn or lean burn. The manufacturer will typically provide information that states if the engine complies with this subpart. Otherwise, a performance test is required to prove compliance with the relevant standard. Emission standards must be met for the life of the engine. Deadlines are provided that restrict importing or installing SI ICE produced in previous model years. Fuel requirements are also applicable if the engines are fueled by gasoline.

Emergency engines that do not meet the non-emergency engine standards must install a non-resettable hour meter for engines: greater than or equal to 500 hp built on or after July 1, 2010; 130 hp to 500 hp built on or after January 1, 2011; less than 130 hp built on or after July 1, 2008. Emergency stationary SI ICE cannot operate more than 100 hours per year, except in emergency situations where there is no limit to the operating hours. Emergency engines can supply power for up to 50 hours under non-emergency conditions. Certain other conditions that depend on voltage, etc. allow for other conditions that allow operation of the emergency engine.

Certified stationary SI ICE typically do not require performance testing if the engine and control device is operated and maintained according to the manufacturer's emission related written instructions. Maintenance records must be kept to demonstrate compliance. Non-certified engines may require performance tests to demonstrate compliance, depending on the maximum engine power. Maintenance records must be kept. Air-to-fuel ratio (AFR) controllers must be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

Test methods and procedures must be complied with to operate a stationary SI ICE. Emissions standards are provided in the tables for pollutants based on the engine power, emergency/non-emergency status, and manufacture date. Performance tests must be met as specified.

SI ICE with greater than 100 hp that operates more than 15 hours per year must submit an annual report beginning for the 2015 calendar year. The annual report is due by March 31, 2016 at the latest. It is possible that a report may be due prior to that for certain engines. Special requirements exist for Guam, American Samoa, the Commonwealth of the Northern Mariana Islands and Alaska.

SUBPART IIII: STANDARDS OF PERFORMANCE FOR STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

This subpart seeks to reduce emissions from stationary compression ignition (CI) internal combustion engines (ICE). This paper will not examine the requirements for manufacturers of stationary compression ignition internal combustion engines; it will only examine the requirements for owners and/or operators of stationary compression ignition internal combustion engines.

This subpart is applicable to: operators of CI ICE that commence construction after July 11, 2005 and are manufactured after April 1, 2006 and are not fire pump engines; and certified NFPA fire pump engines after July 1, 2006.

Stationary CI ICE being tested at a stationary CI ICE test cell/stands are excluded from this subpart. Temporary replacement units located at the site less than one year and that have been certified to meet the standards may be exempt from the other requirements of this provision.

Emission standards are established based on the engine model year. The manufacturer will typically provide information that proves compliance for the engine. Otherwise, a performance test is required to prove compliance with the relevant standard. Deadlines are provided that restrict importing or installing CI ICE produced in previous model years. Fuel requirements are also applicable if the engines are fueled by diesel.

Non-emergency engines must monitor the number of operating hours. If applicable, the diesel particulate filter must be installed with a backpressure monitor that notifies the operator when the high backpressure limit of the engine is approached.

Emergency stationary CI ICE cannot operate more than 100 hours per year, except in emergency situations where there is no limit to the operating hours. Emergency engines can supply power for up to 50 hours under non-emergency conditions. Certain other conditions that depend on voltage, etc. allow for other conditions that allow operation of the emergency engine.

Test methods and procedures must be complied with to operate a stationary CI ICE. Emissions standards are provided in the tables for pollutants based on the engine power, emergency/non-emergency status, model year and displacement specified. Performance tests must be met as specified.

CI ICE with greater than 3,000 hp or CI ICE with greater than 100 hp that operates more than 15 hours per year must submit an annual report beginning with the 2015 calendar year. The annual report is due by March 31, 2016 at the latest. It is possible that a report may be due prior to that for certain engines. Special requirements exist for Guam, American Samoa, the Commonwealth of the Northern Mariana Islands and Alaska.

SUBPART LLL: STANDARDS OF PERFORMANCE FOR SO_2 EMISSIONS FROM ONSHORE NATURAL GAS PROCESSING PLANTS FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JANUARY 20, 1984 AND ON OR BEFORE AUGUST 23, 2011

This subpart seeks to reduce SO_2 emissions from onshore natural gas plants. This subpart was modified to include all natural gas processing plants that are not subject to subpart OOOO due to being constructed prior to August 23, 2011. No other provisions changed in the regulation. Even though this regulation did not have any changes to the standards of the regulation, the entirety of the regulation will be examined due to the number of facilities that could become subject to the regulation due to the change in the applicability date.

This subpart is applicable to each sweetening unit and sweetening unit followed by a flare that were constructed after January 20, 1984 and on or before August 23, 2011. Facilities that have a design capacity less than 2 LTPD of H_2S in the acid gas only have to comply with the recordkeeping and reporting requirements specified. Sweetening facilities producing acid gas that is completely reinjected into an oil-or-gas-bearing geologic strata or that is not released to the atmosphere do not require the compliance tests required in this subpart.

During the initial performance test, a minimum SO_2 emission reduction efficiency must be achieved based on factors provided in the tables of the regulation. The Tutwiler procedure, which is provided in the regulation, or a chromatographic procedure must be used to determine the H_2S concentration in the acid gas. The accumulation of sulfur and H_2S concentration in the acid gas must be monitored for each 24 hour period. A monitoring device must be installed that measures the flow rate of acid gas from the sweetening unit.

A continuous monitoring system must be installed and operated. Specifics of the monitoring system requirements depend on the control system chosen for to reduce sulfur dioxide emissions. The average sulfur emission reduction efficiency must be calculated for each 24-hour period. Special requirements that allow alternate compliance demonstrations exist for facilities with a design capacity less than 150 LTPD of H_2S expressed as sulfur.

Records of calculations and measurements must be kept for two years. Annual reports of excess emissions must be submitted. Excess emissions are defined as any 24-hour period where the average sulfur emission reduction efficiency is less than the minimum required efficiency or (if applicable) any 24-hour period where the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature. If applicable, a record demonstrating that the facility’s design capacity is less than 150 LTPD of H_2S expressed as sulfur.

SUBPART KKK: STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC FROM ONSHORE NATURAL GAS PROCESSING PLANTS FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JANUARY 20, 1984 AND ON OR BEFORE AUGUST 23, 2011

This subpart seeks to reduce emissions from equipment leaks of VOCs from onshore natural gas plants. This subpart was modified to include all natural gas processing plants that are not subject to subpart OOOO due to being constructed prior to August 23, 2011. No other provisions changed in the regulation. Even though this regulation did not have any changes to the standards of the regulation, the entirety of the regulation will be examined due to the number of facilities that could become subject to the regulation due to the change in the applicability date. It affects the following facilities located at a natural gas processing plant: a compressor in VOC or wet gas service, the group of all equipment except compressors within a process unit, a compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit.

Equipment not located at the onshore natural gas processing plant is exempt from these requirements. Equipment within a process unit located at an onshore natural gas processing plant is exempt if the equipment is subject to any LDAR requirements (40 CFR 60 Subparts VV, GGG). Addition or replacement of equipment for process improvement without a capital expenditure is not considered a modification. For example, if an engine at Site A is replaced by a similar engine from Site B, then the requirements will not be triggered. There are also some design standards on certain process equipment that may exempt that equipment from these requirements as well.

Equipment must be monitored for leaks according to the required frequencies (monthly, quarterly, seminannually). Monitoring frequency and leak definitions vary based on the type of equipment and the operating time. If the equipment is found to be leaking, then a weatherproof and readily visible tag must be attached to the leaking equipment. The leak must be repaired within certain timeframes depending on the equipment. Tag removal requirements depend on the equipment. Records of repair attempts and dates must be kept. All records must be kept for two years. Semiannual reports detailing the information in recorded during the reporting period are due every 6 months after the initial startup date.

SUBPART JA: STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER MAY 14, 2007

This subpart seeks to limit emissions from specified facilities within a petroleum refinery. The changes made within this regulation affected the applicability, definitions, and test methods and procedures. Standards for the pollutants, monitoring, reporting, and recordkeeping requirements did not change. Performance test requirements and compliance demonstration provisions did not change either.

This subpart is applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. The sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery. It is important to note that the sulfur recovery plant does not have to be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery. For all units other than flares and delayed coking units, this subpart applies to facilities that started construction after May 14, 2007. It applies to flares that started construction after June 24, 2008. Delayed coking units have three different applicability dates, depending on which definition the facility meets. The regulation also defines the term “modification” that applies specifically to flares; the definition of “modification” found in 60.14 applies to the rest of the facilities.

This subpart provides emission standards for the following pollutants: particulate matter, nitrogen oxides, sulfur dioxide, and carbon monoxide. Specific emission limits exist for sulfur recovery plants based on the configuration and design of the plant. Fuel gas for the fuel gas combustion device must also meet certain emission standards. NOx emission standards for process heaters rated greater than 40 MMBTU/hr are also provided, based on whether it is natural draft, forced draft, co-fired natural draft, or co-fired forced draft process heater. Performance tests required in 60.8 must be completed and compliance with the emission limitations must occur within 180 days of initial startup or within 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, whichever comes first.

Operators of flares are required to develop and implement a written flare management plan. The plan must be submitted by November 11, 2015, or on startup of the newly constructed flare, whichever is later. Operators of fuel gas combustion devices, flares or sulfur recovery plants must conduct a root cause analysis and a corrective action analysis within 45 days when certain conditions are exceeded. The corrective actions must be implemented within 45 days or develop an implementation schedule. Special conditions exist for flares in BAAQMD and SCAQMD, both in California. Requirements for depressurizing the coke drums are included as well.

Requirements for continuous parameter monitoring systems (CPMS), Continuous Opacity Monitoring Systems (COMS), Continuous Emissions Monitoring Systems (CEMS) for FCCU or FCU are included in the regulation. Control device operating parameters are defined for FCCU and FCU subject to the PM emissions limits. The regulation also requires that a bag leak detection system be in place for each baghouse or similar fabric filter control device. For each FCCU and FCU subject to SO_2 limits, an instrument must be installed to continuously monitor and record the concentration of SO_2 emissions into the atmosphere. The instrument must have an O_2 monitor. For each FCCU and FCU subject to CO limits, an instrument must be installed to continuously monitor and record the concentration of CO emissions into the atmosphere.

Sulfur recovery plants must install an SO_2 CEMS. If the sulfur recovery plant is subject to the reduced sulfur compound and H_2S emission limits, then an instrument must be installed for continuously monitoring and recording the concentration of reduced sulfur, H_2S and O_2 emissions into the atmosphere. The operator may choose to convert reduced sulfur to SO_2 via an air or O_2 dilution and oxidation system and monitor those emissions. Excess emissions are defined.

Fuel gas combustion devices subject to SO_2 or H_2S limits and flares subject to H_2S concentration requirements must install a SO_2 CEMS or H_2S monitor on the fuel gas depending on which provisions the device is subject. Exemption is made for low sulfur fuel gases listed in the regulation.

Process heaters complying with the NOx emission limits must install an instrument to continuously monitor and record the concentration of NOx emissions into the atmosphere. The instrument must have an O_2 monitor. Alternative compliance methods exist for process heaters with heating capacities less than 100 MMBTU.

Flares may be required to install CEMS for total reduced sulfur and H_2S to assess root cause analysis. Certain exemptions exist from sulfur monitoring requirements if certain conditions are met. A CPMS to monitor flow must be installed on the flare. Alternative monitoring is available for certain flares equipped with water seals. Alternative monitoring requirements exist for BAAQMD and SCAQMD, in California. Excess emissions are defined.

Performance test requirements to demonstrate compliance are listed. Approved test methods and procedures must be used for monitoring. Daily records must be maintained on each unit. Excess emissions are defined. Special performance test requirements apply to the daily performance tests required that are covered under test methods and procedures in the regulation.

Reporting is required semiannually for all facilities. Daily records must be kept of all data from the continuous monitoring systems. Records must be analyzed for exceedances of emission limits or operating parameters based on 24-hour periods to determine compliance. Any deviations from compliance must be noted in the report. The report must be certified by a responsible official.

SUBPART J: STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES

This subpart seeks to limit emissions from specified facilities within a petroleum refinery. The changes made within this regulation affected the applicability, definitions, and test methods and procedures. Standards for the pollutants, monitoring, reporting, and recordkeeping requirements did not change. Performance test requirements and compliance demonstration provisions did not change either.

This subpart is applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 LTPD or less. It is important to note that the Claus sulfur recovery plant does not have to be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery. Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device other than a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before May 14, 2007, or any fuel gas combustion device that is also a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before June 24, 2008, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction, reconstruction or modification after October 4, 1976, and on or before May 14, 2007, is subject to these requirements .

Any fluid catalytic cracking unit catalyst regenerator that commences construction on or before January 17, 1984, is exempted from the standards for sulfur oxides found in 60.104(b). Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction on or before January 17, 1984, is exempt from this subpart. Operators may choose to comply with subpart Ja instead of this subpart.

This subpart provides emission standards for the following pollutants for operators of any fluid cracking unit catalyst regenerator: particulate matter, carbon monoxide, and sulfur oxides. Fuel gas combustion devices and Claus sulfur recovery plants are subject to the standards for sulfur oxides. Performance tests required in 60.8 must be completed and compliance with the emission limitations must occur within 180 days of initial startup or within 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, whichever comes first. Fuel gas for the fuel gas combustion device must also meet certain emission standards.

Continuous monitoring systems are required for each unit. The specific monitoring system required depends on the unit specifications and design. Approved test methods and procedures must be used for monitoring. Daily records must be maintained on each unit. Conditions that create excess emissions are defined for: opacity, carbon monoxide, sulfur dioxide from fuel gas combustions and sulfur dioxide from Claus sulfur recovery plants. Special performance test requirements apply to the daily performance tests required that are covered under test methods and procedures in the regulation.

Reporting is required semiannually for all facilities. Daily records must be kept of all data from the continuous monitoring systems. Records must be analyzed for exceedances of emission limits or operating parameters based on 7-day and 30-day periods to determine compliance. Any deviations from compliance must be noted in the report. The report must be certified by a responsible official.