The Texas Commission on Environmental Quality (TCEQ, agency, or commission) adopts new §§112.100 - 112.108, 112.110 – 112.118, 112.200 – 112.203, 112.206 – 112.208, 112.210 – 112.213, 112.216 – 112.218, 112.220 – 112.228, 112.230 – 112.238, 112.240 – 112.248, and 112.300 – 112.308.

Sections 112.100 – 112.108, 112.110 - 112.118, 112.200 – 112.203, 112.206 – 112.208, 112.210 – 112.213, 112.216 – 112.218, 112.220 – 112.228, 112.230 – 112.238, 112.240 – 112.248, and 112.300 – 112.308 are adopted *with changes* to the proposed text as published in the April 29, 2022, issue of the *Texas Register* (47 TexReg 2413) and, therefore, will be republished.

The new sections of Chapter 112 will be submitted to the United States Environmental Protection Agency (EPA) as revisions to the State Implementation Plan (SIP).

Background and Summary of the Factual Basis for the Adopted Rules

The federal Clean Air Act (FCAA) (42 United States Code (USC), §§7401 et seq.) requires the EPA to establish primary National Ambient Air Quality Standards (NAAQS) that protect public health and to designate areas as either in attainment or nonattainment with the NAAQS, or as unclassifiable. After a NAAQS is revised, each state is required to submit a SIP revision to the EPA that provides for attainment and maintenance of the NAAQS for areas that are not meeting the revised standard. On June 22, 2010, the EPA published a revised sulfur dioxide (SO_2) NAAQS, adopting a 75 parts per billion (ppb) one-hour primary standard, effective August 23, 2010 (75 *Federal Register* (FR)

35520). SO_2 pollution results from the direct emissions from sources (not as a result of chemical interactions of various compounds in the air) and concentrations of SO_2 are generally expected to be highest closer to emission sources and lowest further away, due to dispersion of emissions in the air. Therefore, this adopted rule establishes site and source specific SO_2 emission limits and associated requirements to ensure attainment of the 2010 SO_2 NAAQS as discussed further in this rule preamble.

On March 26, 2021, the EPA published designations for portions of Howard, Hutchinson, and Navarro Counties as nonattainment for the 2010 SO_2 NAAQS, effective April 30, 2021 (86 FR 16055). The attainment date for all three nonattainment areas is April 30, 2026. An air quality modeling analysis showing that enforceable emission limits will provide for attainment of the NAAQS is part of the required attainment demonstration SIP revisions being adopted concurrently with this adoption for the nonattainment areas. The air quality modeling analyses indicate that reductions from current actual and allowable emission rates are needed in each of the three nonattainment areas. To provide time for implementation and compliance as well as to provide at least one full calendar year of data, the reductions are required to occur by January 1, 2025, except for the sources that companies indicated could comply earlier. The agency adopts these rules to make the emissions reductions necessary to demonstrate attainment. The adopted rules will be submitted to the EPA as a revision to the SIP and, upon EPA approval, will be both state and federally enforceable.

The concurrently adopted attainment demonstration SIP revisions include a technical analysis to determine the level of emission reductions necessary to attain the 2010 SO_2 NAAQS in each of these nonattainment areas. In addition to other requirements, the attainment demonstration includes an assessment of all sources that emit SO_2 in the nonattainment area, modeling that demonstrates attainment of the NAAQS, and the corresponding emission limits and other requirements for SO_2 sources in the nonattainment area. The attainment demonstration modeling is the basis for the commission's determination regarding the necessity for the emission reductions required by these adopted rules. Information concerning the concurrent attainment demonstration SIP revision adoptions for each nonattainment area are available on the commission's website or by contacting commission staff associated with this rulemaking.

As part of the concurrently adopted SIP revisions, the TCEQ modeled the information provided by each site in each nonattainment area. Current allowable emission rates or lower emission rates required to demonstrate attainment were included in the modeling. The EPA has historically used pollutant-specific concentration levels, known as significant impact levels (SIL), to identify the degree of air quality impact that causes or contributes to a violation of a NAAQS or Prevention of Significant Deterioration increment. As a result, the TCEQ used the SIL for SO_2 of 3 ppb or 7.85 micrograms per cubic meter ($\mu g/m^3$) to determine which sources were the most significant contributors to nonattainment. The TCEQ identified the emission rates that modeled attainment by using an iterative process that included both modeling of all SO_2 emissions in a nonattainment area and consultation with companies to ensure that source characteristics and operational practices were correctly represented. The adopted rules for each nonattainment area covered in this adopted rulemaking specify the emission rates needed to model attainment, as indicated in the concurrently adopted SIP revisions for Howard, Hutchinson, and Navarro Counties.

The FCAA, §172(c)(1), requires that nonattainment area SIP revisions also incorporate all reasonably available control measures (RACM), including reasonably available control technology (RACT), for sources of relevant pollutants. The EPA explains in its April 23, 2014, memorandum *Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions* (2014 SO_2 SIP guidance) that states should consider all RACM, including RACT, that can be implemented in light of the attainment needs for the affected SO_2 nonattainment area; and those control measures must be permanent and enforceable. EPA considers that which is necessary for attainment of the 2010 SO_2 NAAQS to be RACM including RACT. Air quality dispersion modeling demonstrates that emission limits established in the adopted rule will result in attainment of the 2010 SO_2 NAAQS. The emission rates provided in these adopted rules for the specific sources were identified by the modeling in the concurrently adopted SIP revisions as necessary to attain the 2010 SO_2 NAAQS in the associated nonattainment areas. Because the adopted emission rates from the specified sources were identified as sufficient to demonstrate attainment, the commission determined that those requirements provide for the necessary emissions reductions of SO_2 to satisfy RACM, including RACT, for the sources of SO_2 identified in the affected areas as contributing to nonattainment.

The adopted rules for each nonattainment area are specific to the sites and sources that emit SO_2 within those areas, and the adopted rules will continue to apply to the sites and sources regardless of ownership, operational control, or other documentation-related changes. To ensure that applicability is clear for both the public and current regulated entities, the adopted rules specify the emission point numbers (EPN) for each source (production unit or control device), at each site, with street addresses or location coordinates added at adoption in the Applicability sections of the rule divisions and Subchapter G because the rule provisions prohibiting changes to regulated entity numbers (RN) are removed at adoption. The adopted rules are based on specific information provided by the affected companies or where information on anticipated changes was not provided, alternative sources of information for control options to achieve the emission reductions required for attainment. In some cases, requirements are also based on provisions for the control of SO_2 in consent decrees between the companies and the EPA for specific sites, and in no case do the adopted rules conflict with consent decree requirements.

The rules are adopted in Chapter 112, Control of Air Pollution from Sulfur Compounds as new Subchapter E, Requirements in the Howard County Nonattainment Area; Subchapter F, Requirements in the Hutchinson County Nonattainment Area; and Subchapter G, Requirements in the Navarro County Nonattainment Area with a separate division for each site, as applicable. The provisions in each division are covered in the same order for consistency. The emission limits in the adopted rules do not provide authorization for emissions by the sources. As required by commission rules, emission authorization is required as specified in 30 Texas Administrative Code (TAC) Chapters 106, 116, and 122. If adopted by the commission and approved by the EPA, the emission limits and associated requirements specified for the sources in new Subchapters E, F, and G will satisfy RACT and RACM requirements necessary to attain and maintain the 2010 SO_2 NAAQS. The emission limits and associated requirements apply only to the specific sources identified in the adopted rules. To ensure the continued applicability of the specified emission limits and associated requirements, the adopted rules contain prohibitions on changing an EPN designation for the sources subject to these rules.

The Howard County SO_2 nonattainment area designated by the EPA consists of a portion of Howard County. The Alon USA LP's (Alon) Alon USA Big Spring Refinery site (Alon USA Big Spring Refinery), the Tokai Carbon CB LTD's (Tokai) Tokai Big Spring Carbon Black Plant site (Tokai Big Spring Carbon Black Plant), and BHER Power Resources Inc's (BHER) C R Wing Cogeneration site (BHER C R Wing Cogeneration Plant) are the sites with SO_2 emissions within the Howard County nonattainment area. The Alon USA Big Spring Refinery manufactures transportation fuels, solvents, finished asphalt, and liquified petroleum gas. The Tokai Big Spring Carbon Black Plant manufactures carbon black for use in various industrial applications, such as tires. The BHER C R Wing Cogeneration Plant generates electricity. Both the Alon USA Big Spring Refinery and Tokai Big Spring Carbon Black Plant are the sites covered in Subchapter E. The BHER C R Wing Cogeneration Plant is not included in the rules because attainment demonstration modeling showed its contribution to the modeled design value in the nonattainment area does not exceed the SIL.

The Hutchinson County SO_2 nonattainment area designated by the EPA consists of a portion of Hutchinson County. There are eight sites with SO_2 emissions in the nonattainment area, owned and/or operated by the following regulated entities: 1) Chevron Phillips Chemical Company LP's (CP Chem) Borger Plant (CP Chem Borger Plant); 2) IACX Rock Creek LLC's (IACX) Rock Creek Gas Plant (IACX Rock Creek Gas Plant); 3) Orion Engineered Carbons LLC's (Orion) Borger Carbon Black Plant (Orion Borger Carbon Black Plant); 4) Phillips 66 Company's (Phillips 66) Phillips 66 Borger Refinery (P66 Borger Refinery); 5) Tokai's Borger Carbon Black Plant (Tokai Borger Carbon Black Plant); 6) Agrium US Inc's Agrium Borger Nitrogen Operations site (Agrium Borger Nitrogen Plant); 7) Borger Energy Associates LP's (Borger Energy) Blackhawk Power Plant; and 8) Solvay Specialty Polymers USA LLC's (Solvay) Solvay Specialty Polymers USA site (Solvay Specialty Polymers Plant). The CP Chem Borger Plant manufactures specialty chemicals and plastics with other various industrial applications. The IACX Rock Creek Gas Plant is a natural gas gathering plant. The Orion Borger Carbon Black Plant manufacturers carbon black for use in various industrial applications, such as tires. The P66 Borger Refinery processes primarily medium sour crude oil and natural gas oil. The Tokai Borger Carbon Black Plant manufacturers carbon black for use in various industrial applications, such as tires. The Agrium Borger Nitrogen Plant is a fertilizer plant. The Blackhawk Power Plant generates electricity using natural gas and steam using refinery gas from the P66 Borger Refinery. The Solvay Specialty Polymers Plant is a plastics and resins plant on the Chevron Phillips Chemical property that operates independently from Chevron Phillips Chemical. The first five sites with SO_2 emissions are covered in Subchapter F. The other three sites are not included in the rules because attainment demonstration modeling showed their contribution to the modeled design value in the nonattainment area does not exceed the SIL.

The Navarro County SO_2 nonattainment area designated by the EPA consists of a portion of Navarro County. The Arcosa Lightweight Streetman plant (Streetman) owned and operated by Arcosa LWS, LLC (Arcosa), is the only site with SO_2 emissions in the nonattainment area. The Streetman Plant manufactures lightweight aggregate for use in various industrial applications, such as concrete and asphalt, and is the site covered in Subchapter G.

Throughout the rules at adoption, changes are made to correct typographical errors, punctuation, and the use of acronyms within each section, consistent with *Texas Register* requirements. Additionally, the designation of sources is made consistent by citing the name of the source first followed by its EPN in parentheses, except for caps from flexible permits that do not name the cap or individual EPNs and a fugitive emissions EPN that includes two distinct areas that were modeled separately and have different emission rates required, for which the source names and EPNs from the modeling are used. Where used, the term “facility” is replaced by the term “source” for consistency. None of these changes are intended to change the meaning of the proposed rule language except where they are made as part of, and in conjunction with, other changes to rule language that are discussed in this preamble.

Section-by-Section Discussion

SUBCHAPTER E: REQUIREMENTS IN THE HOWARD COUNTY NONATTAINMENT AREA

DIVISION 1: REQUIREMENTS FOR THE ALON USA BIG SPRING REFINERY

§*112.100, Applicability*

The commission adopts new §112.100 to specify that the new rules apply to sources of SO_2 at the Alon USA Big Spring Refinery site at which the agency has determined emissions contribute to potential exceedances of the 2010 SO_2 NAAQS based on modeling conducted for the concurrently adopted SIP revisions discussed elsewhere in this preamble. The specific sources at the site with a modeled contribution above the SIL at any receptor are specified as being subject to the adopted rules.

The adopted rule provisions in the new Division 1 are site-specific and unit-specific and are specified by the address of the site and EPN as documented in a specified version of the New Source Review (NSR) permit. The address of the site is added at adoption in place of the RN because the provision proposed as §112.102(a), which would have required approval for changing the RN, is removed at adoption. This will eliminate the need for a SIP revision if the RN changes. The source name and EPN used in attainment demonstration modeling is used in the rules for sources to be authorized, constructed, or modified after this adopted rulemaking. The requirements will continue to apply regardless of any changes of ownership, control, or documentation of the affected sources.

Based on comments, the last sentence of §112.100(a) is removed. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA, which was the intent of the proposed language. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. After the EPA's approval, the rules are enforceable by both the EPA and the TCEQ. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until it approves a revision to the SIP for their removal.

The TCEQ conducted attainment demonstration modeling for sources in the Howard County nonattainment area using either the current allowable emission limits (including during both normal operations and, when applicable, authorized MSS activities) from the NSR permit(s) for each site, or lower emission rates if needed to demonstrate attainment. The lower emission rates were used in the attainment demonstration modeling, which also used corresponding stack parameters supplied by the companies for each emissions point where SO_2 is emitted. Modeling was conducted to determine which specific sources have emissions that contribute at a level greater than the SIL of 3 ppb (i.e., 7.85 $\mu g/m^3$) to the modeled design value concentrations at any receptor in the Howard County SO_2 nonattainment area. If the source had a contribution to the modeled design value that was less than the SIL at all receptors, it was not included in the rules. If the source had a contribution to the modeled design value that was greater than the SIL, its emission rates and, as appropriate, other associated control, monitoring recordkeeping and reporting requirements were specified in the rules. When modeled collectively with all emissions sources in the nonattainment area and evaluated using a Monte Carlo simulation statistical approach, the emission rates specified in the rule resulted in modeled design values that demonstrated attainment of the NAAQS. Monte Carlo methods are statistical simulation techniques used to estimate possible outcomes from uncertain events by repeatedly calculating an outcome, in this case the modeled design value, by randomly selecting from a set of possible scenarios, in this case emission rates for sources in the nonattainment area, for each calculation.

In §112.100(b), the phrase "source name" is moved at adoption to before "emission point number" because source name is made to occur first consistently throughout the rules in this division for the sources subject to the rules. To achieve this consistency, the occurrence of the source name and EPN is switched at adoption for each facility in the subsequent paragraphs.

§112.101, Definitions

The commission adopts new §112.101 to define four terms used in Division 1. The commission adopts new §112.101(1) to define block one-hour average, which is used in the requirements. At adoption, a definition for continuous monitoring is added as new §112.101(2) based on an EPA comment. The subsequent definitions are renumbered. Adopted new §112.101(3), which was proposed as §112.101(2), defines the Howard County SO_2 nonattainment area; at adoption, the citation of the *Federal Register* publication is removed because it is not needed. Adopted new §112.101(4), which was proposed as §112.101(3), defines pipeline quality natural gas.

§112.102, Control Requirements

The commission adopts new §112.102 to specify the control requirements for applicable sources (designated through the relevant EPN) that were identified in §112.100. The emission rates and other control requirements established in the section are the controls by which modeling demonstrates attainment in the concurrently adopted SIP revision for Howard County.

Proposed §112.102(a), which would have prohibited the owner or operator from contravening the control requirements specified in these rules by changing the site's RN or the EPN designation of any source without prior approval by the agency and the EPA, is removed at adoption based on public comment. The EPA stated that the only manner of approval for such a change would be a full SIP revision, which is overly burdensome. The subsequent subsections are re-lettered.

Adopted new §112.102(a), which was proposed as §112.102(b), provides the emission limits for the fluidized catalytic cracking unit (FCCU), currently designated as FCCU ESP Stack EPN 06ESPPCV in NSR Permit 49154, with the order of the source name and EPN switched at adoption for consistency Permit 49154 currently has an emission limit of 669.90 pounds per hour (lb/hr) SO_2 for the FCCU (EPN 06ESPPCV). Alon committed to reduce the FCCU maximum SO_2 emission limit to 250.00 lb/hr on a seven-day rolling average. This number was determined by applying a discount factor to 280.90 lb/hr, which was the number used in the attainment demonstration modeling. Alon submitted 2017 through 2020 FCCU continuous emissions monitoring system (CEMS) emissions data to support their conclusion that a 250.00 lb/hr limit on a seven-day rolling average is equivalent to 280.90 lb/hr SO_2 on a one-hour average basis. The 2014 SO_2 SIP guidance indicated that there may be cases in which an averaging time longer than one-hour may be appropriate provided that any emissions limits based on averaging periods longer than one hour are designed to have comparable stringency to a one-hour average limit at the modeled critical emission value (CEV). The EPA indicated that if periods of hourly emissions above the CEV are a rare occurrence at a source, particularly if the magnitude of the emissions is not substantially higher than the CEV, these periods would be unlikely to have a significant impact on air quality. The EPA further indicated that they do not expect that the use of longer-term averages will be necessary in cases where sources' emissions do not exhibit a high degree of variability. Therefore, the EPA recommends limiting the use of this approach to only those instances where a source's normal emissions variability would result in one-hour limits being extremely difficult to achieve in practice.

The 2014 SO_2 SIP guidance included a recommended approach to determine an appropriate longer-term averaging limit than a block one-hour emission rate. This approach involves calculating an appropriate longer-term averaging limit as a percentage of the one-hour CEV limit that would otherwise be applied to the source of SO_2 emissions. The first step of these calculations is to conduct air dispersion modeling to determine the CEV defined as the one-hour SO_2 emissions limit that shows attainment of the 2010 SO_2 NAAQS through modeling.

The discount factor is a percentage applied to the CEV that results in an emissions limit on a longer averaging time that can be expected to be comparably stringent as an emissions limit on a one-hour basis. This approach reconciles the inherent variability in hourly SO_2 emissions in the operations of some sources that may subsequently prove difficult to demonstrate compliance with an emissions limit on a one-hour basis. The EPA generally expects sources with longer averaging time limits to experience some occasions of hourly emissions to exceed the CEV while the majority of hourly emissions will remain below the CEV. This approach to establishing an emissions limit on a longer averaging time is expected to result in an emissions limit that remains protective of the 2010 SO_2 NAAQS because it is unlikely that the limited occurrences of hourly SO_2 emissions above the CEV would coincide with times when the meteorology is conducive for high ambient concentrations of SO_2.

The recommended approach involves calculating an appropriate longer-term averaging limit as a percentage of the one-hour CEV limit. The TCEQ used the 280.90 lb/hr SO_2 one-hour average emission limit value in the concurrently adopted attainment demonstration modeling to prove that the longer-term emission limit value is not expected to result in exceedances of the 2010 SO_2 NAAQS. For the FCCU, the adopted rule has a 250.00 lb/hr SO_2 emission limit on a seven-day rolling average. Alon provided technical data concerning hourly mass SO_2 emissions from the FCCU at the Alon USA Big Spring Refinery. The historical emissions data submitted for each operating hour of the FCCU were used for the emissions variability analysis to arrive at a final SO_2 emissions limit on a seven-day rolling average. Specifically, the 99th percentile of the one-hour pounds per hour data was obtained as well as the 99th percentile of the seven-day rolling average pounds per hour data. The ratio of the 99th percentile of the seven-day rolling average data to the 99th percentile of the one-hour data was then calculated to develop a discount factor to be applied to the one-hour CEV limit to arrive at the final limit that provides for a longer averaging time basis. The final discount factor for the pounds per hour emissions limit representing the modeled one-hour CEV was determined to be 0.89. The discount factor is expected to provide a degree of comparable stringency to the corresponding limit on a one-hour basis. The emission rate calculated using the discount factor is expected to constrain emissions from the FCCU so that any emissions above the CEV will be limited in frequency and magnitude.

Adopted new §112.102(b), which was proposed as §112.102(c), limits the fuel and waste gas sulfur content limits for the flares. At adoption, the source name of each flare is added before its EPN for consistency, and the acronym "ppmv" is removed because it is not used again in this section. Based on a comment received from Alon, a change is made at adoption to add the phrase "except as provided for in 40 CFR§60.103a(h)." The change is intended to make the concentration-based emission limit applicable to waste gases that were generated during normal operations and not from a relief valve leak because 40 CFR Part 60, Subpart Ja and other federal requirements do not require compliance with emissions standards for relief valves and gases generated during MSS activities when controls may not be on-line. MSS emissions are limited by the pound per hour emission rates rather than the concentration limit that may not be achievable during MSS.

Adopted new §112.102(c) - (f), which were proposed as §112.102(d) – (g), include emission limits for the four flares during both normal operations and authorized MSS activities. The SO_2 emission limits for normal operations are as follows: 25.00 lb/hr for Northeast Flare (EPN 14NEASTFLR), 51.80 lb/hr for the Crude Flare (EPN 02CRUDEFLR), 103.70 lb/hr for the Reformer Flare (EPN 05REFMFLR), and 118.70 lb/hr for the South Flare (EPN 16SOUTHFLR). The MSS emission limits are based on the maximum number of days per year emissions can fall into specified ranges for each flare during authorized MSS activities. Limits on the number of days per year flaring events could generate specified amounts of emissions were needed to demonstrate attainment and were tested in the Monte Carlo demonstration in the associated concurrently adopted attainment demonstration. The rule specifies emissions limits for each flare during authorized MSS activities, for the specified number of days and corresponding emission range. The emission limit ranges with the associated number of days allowed for each flare are 1) the Northeast Flare (EPN 14NEASTFLR) can emit SO_2 in the following ranges: 25.01 lb/hr or more but less than 250.01 lb/hr for no more than four calendar days each year; 250.01 lb/hr or more but less than 500.01 lb/hr for no more than six calendar days each year; and 500.01 lb/hr or more but less than 1,500.01

lb/hr for no more than two calendar days each year; 2) the Crude Flare (EPN 02CRUDEFLR) can emit SO_2 in the following ranges: 51.81 lb/hr or more but less than 250.01 lb/hr for no more than 14 calendar days each year, and can operate in the range of 250.01 lb/hr or more but less than 750.01 lb/hr for no more than three calendar days each year; 3) the Reformer Flare (EPN 05REFMFLR) can emit SO_2 in the following ranges: 103.71 lb/hr or more but less than 250.01 lb/hr for no more than four calendar days each year, and can operate in the range of 250.01 lb/hr or more but less than 750.01 lb/hr for no more than five calendar days each year; and 4) the South Flare (EPN 16SOUTHFLR) can emit SO_2 in the following ranges: 118.71 lb/hr or more but less than 250.01 lb/hr for no more than four calendar days each year, can operate in the range of 250.01 lb/hr or more but less than 500.01 lb/hr for no more than 12 calendar days each year, and can operate in the range of 500.01 lb/hr or more but less than 1,696.01 lb/hr for no more than two calendar days each year. For each source, there is also a prohibition on emissions above the highest emission rate in the final range because attainment demonstration modeling shows that emissions above these levels may contribute to an exceedance of the 2010 SO_2 NAAQS. In the case that emissions fall within more than one range in different hours of a day, the allowable number of days per year is based on the highest emission rate of the day.

These MSS emission rate range limits and allowable number of days were tested in the Monte Carlo simulations by identifying the possible combinations of emission occurrences and conducting 2.5 million Monte Carlo simulations to demonstrate that these potential MSS scenarios do not create an exceedance of the 2010 one-hour SO_2

NAAQS. The above alternative emissions and associated duration limits for MSS scenarios begin just above the routine emission limit and increase sequentially through the maximum limit. Each alternative emission limit allows for emissions within the specified range for the specified number of calendar days, with a provision for each flare that if emissions within different ranges occur during a calendar day, only the highest emission rate is used to determine the emission rate range that applies for that day. The range applicable to a specific day is based on the maximum hourly rate during that day, with the highest emission rate applying.

The commission adopts in new §112.102(g) and (h), which were proposed as §112.102(h) and (i), to limit SRU Incinerator 1 (EPN 69TGINC) to 17.03 lb/hr SO_2 and limit SRU Incinerator 2 (EPN 71TGINC) to 12.78 lb/hr SO_2.

Adopted new §112.102(i), which was proposed as §112.102(j) to allow the owner or operator to request an alternative SO_2 emission limit, is changed at adoption to allow the owner or operator to submit an application for an alternate means of control (AMOC) if certain requirements are met. The commission solicited comments on whether an additional mechanism to submit an application for alternative SO_2 emission limits, similar to the AMOC provisions in 30 TAC Chapter 115, Subchapter J, Division 1, is appropriate to include in Subchapter F. Based on a comment received from the EPA that the only approvable request for changing an emission limit is a full SIP revision, proposed §112.102(j) is not adopted as proposed but is instead changed to a provision allowing sources to submit an application for an AMOC. Because of the relettering, the provisions for AMOCs are adopted as new §112.102(i). They are adopted with the rules for the Alon USA Big Spring Refinery to have the rules consistent with those for the P66 Borger Refinery. Alon, Phillips 66, and other companies commented in favor of the flexibility that would be provided by the proposed rule provisions. In comments, Phillips 66 provided draft language for AMOC that is based on the provisions of 30 TAC Chapter 115 Subchapter J Division 1, which has previously been approved by the EPA as part of the SIP for ozone nonattainment areas. The commission is providing provisions for AMOC that are based on draft language submitted in Phillips 66's written public comment but with some changes to be a rule subsection rather than a separate division, to avoid constraining the options of the executive director, and to conform to *Texas Register* and Texas Legislative Drafting Council requirements.

Adopted new §112.102(i)(1) specifies that use of the AMOC provisions does not change the owner or operator's responsibility to comply with permit requirements for new construction or modifications of sources.

Adopted new §112.102(i)(2) describes the criteria for applying for an AMOC plan. Subparagraph (A) provides that the owner or operator of a site subject to these adopted rules can apply, that the executive director must review submitted plans and may approve plans that meet the criteria and procedures of this section, and that if a plan does not meet the necessary criteria, the owner or operator can submit a request for a site-specific SIP revision instead. Subparagraph (B) provides that an applicant for a plan may request a waiver from the public notice requirements. Subparagraph (C) clarifies that applying for an AMOC does not relieve the owner or operator from complying with the rule requirements prior to a decision, and subparagraph (D) specifies that the provisions of an approved AMOC plan are enforceable.

Adopted new §112.102(i)(3) provides the criteria for approval of AMOC plans. All of the criteria must be met for a plan to be approved. Subparagraph (A) specifies that all sources covered by a plan must be and remain at the same site, except that paragraph (8) allows for plans covering contiguous sites in some circumstances. Subparagraph (B) specifies that if the AMOC plan includes an increase in the emission limit for a source subject to the control requirements in this subchapter, the AMOC plan must also include an equivalent decrease in the emission limit for one or more sources subject to the control requirements of the subchapter. This provision limits applicability of the AMOC to sources subject to the rules. Subparagraph (C) describes the demonstration that must be included in an AMOC plan application: in accordance with clause (i), defines the maximum allowed net increase in the off-property ground-level concentration of SO_2 on a highest, first-high basis at any receptor based on the lower of the critical ground-level value or the SIL; clause (ii) specifies that the demonstration must be based on modeling, databases, or the requirements of 40 CFR Part 51, Appendix W and the modeling conducted for the current SIP revisions. Subparagraph (D) specifies that the AMOC must be implemented and the reductions made after the effective date of the rule, such that the attainment demonstration modeling done for the SIP revision that is concurrent with this rulemaking is complete. Subparagraph (E) requires that the AMOC establish control requirements and monitoring, testing, recordkeeping and reporting requirements consistent with, and no less stringent than, the applicable requirements of the subchapter that render the control requirements enforceable.

Adopted new §112.102(i)(4) provides the procedures for submitting an AMOC plan. Subparagraph (A) requires that the owner or operator submit an AMOC plan application and demonstration to the executive director with copies to the local TCEQ regional office, any air pollution control program with jurisdiction, and the EPA regional office. Subparagraph (B) specifies the information that must be included in a proposed AMOC plan: clause (i) specifies the applicant and site identification and contact person information; clause (ii) specifies the information to identify and describe the sources covered, the applicable rule provisions, and the normal operating conditions of the sources; clause (iii) specifies the control requirements for each source that would be made enforceable by the AMOC plan; clause (iv) specifies a demonstration that the AMOC plan meets all requirements of paragraph (3); clause (v) specifies the information to be provided concerning the air pollution control program(s) with jurisdiction; clause (vi) specifies that any other relevant information requested by the executive director must be provided. Subparagraph (C) provides that the representations made for an AMOC plan become enforceable requirements upon approval of the plan by the executive director and the EPA, including emission limits, control requirements, monitoring, testing, reporting, and recordkeeping requirements. Subparagraph (D) specifies that applications for amending or revising AMOC plans must be submitted in accordance with the requirements of the subsection.

Adopted new §112.102(i)(5) provides the procedure for approving AMOC plans. Subparagraph (A) requires that notice sent by the executive director for a preliminary determination of approval must include a copy of the AMOC plan that was preliminarily approved. Subparagraph (B) requires that notice sent by the executive director for a determination to deny must include the reasons for the denial and specifies the determination is the final action of the executive director that is appealable to the Commission. Subparagraph (C) requires that upon receipt of the executive director's notice of preliminary approval, the applicant pay to publish notice, consistent with paragraph (6), of the applicant's intent to obtain an AMOC and the opportunity to provide written comment. Subparagraph (D) requires that the executive director consider all significant and timely comments received and to prepare a written response. Subparagraph (E) provides that the executive director may in response to comments modify provisions of an AMOC plan, deny a plan, or approve a plan without change. Subparagraph (F) requires that the executive director send by a means documenting receipt a written notice of the final determination on an AMOC plan to the applicant, the EPA regional office, any air pollution control program with jurisdiction, and each commentor and that the notice include the final AMOC plan provisions, the response to comments, and announcement of the opportunity to appeal the decision to the Commission. Subparagraph (G) provides that a recipient of the notice in subparagraph (F) may file an appeal of the decision within 15 days of receipt, that the appeal may be considered at the Commission's next regularly scheduled meeting that allows for adequate notice, and that the Commission may remand the determination to the executive director, deny the AMOC plan, or issue the AMOC plan unchanged. Subparagraph (H) specifies that within 45 days of final approval by the executive director (or the Commission for an appeal), the EPA may notify in writing the agency of their disapproval of the decision, including their reasons for disapproval and a specific listing of the changes to the AMOC plan needed for their approval, that the EPA can inform the agency prior to the 45-day deadline that they do not intend to disapprove, and that upon receipt of a timely EPA disapproval, the executive director must void or revise the AMOC plan and reissue notice under subparagraph (F). Subparagraph (I) specifies that if an appeal is not filed for an AMOC plan, it becomes effective upon the EPA's acceptance as provided in subparagraph (K). Subparagraph (J) specifies that if an appeal is not filed for an AMOC plan, it becomes effective upon the latter of the Commission's or the EPA's acceptance. Subparagraph (K) defines EPA acceptance as the explicit approval of a AMOC plan, notification by the EPA that they do not intend to disapprove, or failure of the EPA to meet the 45-day deadline for filing a disapproval.

Adopted new §112.102(i)(6) provides the format of public notice for an AMOC plan. Subparagraph (A) requires that notice be published in two successive issues of a general circulation newspaper closest to the site requesting the AMOC plan. Subparagraph (B) requires that the notice include the application number assigned by the executive director for the AMOC plan, the applicant's name, the type of source(s) and site covered in the AMOC, the location of the site, a brief description of the AMOC plan, the executive director's preliminary determination of approval, the location where copies of the proposed AMOC and related documentation and the executive director's preliminary analysis are available (including the TCEQ regional office, any local air pollution control program, and the EPA regional office), announcement of the opportunity to submit written comments and the procedure for doing so, the length of the public comment period (at least 30 days after the final notice publication), and the contact information for further information at the TCEQ regional office. Subparagraph (C) prohibits the executive director from taking final action until the applicant provides proof of adequate notice to the agency, the EPA, and any air pollution control program with jurisdiction.

Adopted new §112.102(i)(7) covers reviews of approved AMOC plans and termination of plans. Subparagraph (A) specifies that the term "compliance date" means when a source must comply with new or modified sections of Chapter 112. Subparagraph (B) specifies that an AMOC plan becomes void on the compliance date for a new or modified section affecting the source subject to the plan unless the plan is revised to reflect the new requirements. Subparagraph (C) specifies that the holder of an AMOC plan must comply with the rule requirements if the plan becomes void. Subparagraph (D) requires that upon final approval, the owner or operator keep a copy of the AMOC plan on site and available to representatives of the TCEQ, the EPA or an air pollution control program with jurisdiction. Subparagraph (E) requires that an AMOC plan holder submit a demonstration that the plan continues to meet all applicable rule requirements upon request from the executive director. Subparagraph (F) specifies that when a rule change is made that affects an AMOC plan, the holder is responsible for obtaining a new AMOC plan prior to the compliance date of the rule revision.

Adopted new §112.102(i)(8) provides that an AMOC plan may cover multiple sources on contiguous properties if separate applications for approval are submitted by each owner or operator.

§112.103, Monitoring Requirements

The commission adopts new §112.103 to specify the monitoring required for each affected source identified as subject to these rules in §112.100. The adopted monitoring requirements are necessary to demonstrate that the control requirements in §112.102 for that source are met. Adopted new §112.103 provides the monitoring requirements for sources at the Alon USA Big Spring Refinery.

Adopted new §112.103(1) requires a CEMS unit must be used, calibrated, and maintained for the FCCU in compliance with federal regulations to record emissions at least every 15 minutes so that a block one-hour average can be calculated from the data. Because 40 Code of Federal Regulations (CFR) §60.105a(g)(1), (2) and (5), which are cited to establish the monitoring requirements for EPN 06ESPPCV to document compliance with an emission limit in units of pounds per hour, requires monitoring of a concentration-based emission limit and therefore does not require an exhaust gas flow meter, a requirement to have a totalizing gas flow measurement system is added at adoption so that the required monitoring is clear. Because a temperature monitor is needed to convert the exhaust monitoring to standard conditions for the pound per hour emission limit, a requirement to have a temperature monitor is added at adoption. Because the monitors must have sufficient accuracy to demonstrate compliance with the new emission limit, an accuracy requirement is added at adoption for each component of the monitoring system. Because EPN 06ESPPCV is not subject to 40 CFR Part 60, Subpart Ja, which is where the cited provision is codified, language is added at adoption to clarify that the monitoring provisions in §60.105a(g)(1), (2), and (5) apply regardless of the applicability of Subpart Ja to the FCCU.

Adopted new §112.103(2) requires, as proposed, determining each flare's inlet stream flow rate and total sulfur concentration according to 40 CFR §60.107a(e) monitoring procedures and specifications, but at adoption provisions are added to require determining the inlet temperature of the gas stream because this is needed for the calculation method options that are added at adoption based on comments received. Added at adoption based on a comment from the EPA, new §112.103(2)(A) provides the requirement that a separate dedicated totalizing gas flow meter be used to monitor flow rates of flared gases routed to each flare. Added at adoption based on a comment from the EPA, §112.103(2)(B) provides the requirement that a separate temperature monitor be used to monitor the temperature of flared gases at the inlet of each flare. Both §112.103(2)(A) and (B) also provide the accuracy requirement for the respective monitor and require that the monitor be installed, calibrated, maintained, and operated according to manufacturer's recommendations and specifications. Added at adoption, new §112.103(2)(C) provides two options for monitoring the sulfur content of the flared gases. The provision adopted as §112.103(2)(C)(i) requires the use of a total sulfur analyzer that measures SO_2, hydrogen sulfide (H_2S), and total organic sulfur (i.e., total sulfur) in accordance with 40 CFR §60.107a(e)(1), specifies the accuracy requirement, and includes an equation for determining the SO_2 emissions. The provision adopted as §112.103(2)(C)(ii) provides the option for use of an analyzer that measures H_2S alone, which is used with a total sulfur correlation sampling ratio, as allowed for the determination method in 40 CFR §60.107a(e)(2), specifies the accuracy requirement, and includes an equation for determining the SO_2 emissions. Added at adoption based on an EPA comment that calculation methods are needed, Figure 30 TAC §112.103(2)(C)(i) and Figure 30 TAC §112.103(2)(C)(ii) provide the equations for calculating emissions from the total sulfur monitoring data or from the monitoring of H_2S as a surrogate for total sulfur, respectively.

Adopted new §112.103(3) requires the use, calibration, and maintenance of CEMS units, including flow measurement systems and temperature monitors specified at adoption along with accuracy requirements for each component, for the SRU incinerators to record emissions at least every 15 minutes so that a block one-hour average can be calculated from the data. At adoption, it is clarified that a separate monitoring system is required for each SRU stack and that the requirement that the monitoring systems comply with 40 CFR §60,106a(a) applies despite the fact that the SRU units are not subject to that regulation. Because a new §112.103(5) is added at adoption, the word "and" is deleted at the end of §112.103(3).

Adopted new §112.103(4) requires the use of an appropriate quality assurance and quality control (QA/QC) process to validate continuous monitoring data for at least 95% of the time the monitored emissions point has emissions; and use of an appropriate data substitution process, which is the most accurate method available. Because a new §112.103(5) is added at adoption, the word "and" is added at the end of §112.103(4).

A new provision is added at adoption as §112.103(5) based on comments to allow the executive director of the agency to approve minor modifications of monitoring methods. As in the similar provision in 30 TAC §115.725(m), executive director approval and validation of the modified method using 40 CFR Part 63, Appendix A, Test Method 301, as applicable, is required for a modified monitoring method to be used. The language specifies that minor modifications include increases of the frequency of monitoring and replacements of parametric monitoring with a CEMS provided the quality control, quality assurance, and data validation requirements and accuracy specifications are specified and are at least as stringent as required in the rules.

§112.104, Testing Requirements

Adopted new §112.104 provides the testing requirements for sources at the Alon USA Big Spring Refinery, including performance tests on sources subject to Division 1. Adopted new §112.104(1) requires performing relative accuracy tests in accordance with federal requirements for CEMS at the refinery. Adopted new §112.104(2) requires flow rate and sulfur monitoring instrumentation for flares to undergo the initial operational and calibration tests in accordance with the manufacturer's specifications so measurement data can be relied upon to produce an accurate compliance demonstration by the deadline required in §112.108. At adoption, language is added to §112.104(2) to clarify that retesting of previously tested flare monitoring devices is only required if appropriate documentation of the previous testing is not available. Adopted new §112.104(3) requires that additional performance testing be conducted according to federal requirements if requested by the executive director.

§112.105, Approved Test Methods

The commission adopts new §112.105 to specify the test methods required to comply with the testing requirements in adopted new §112.104. The test methods relate to the testing requirements in adopted new §112.104. Adopted new §112.105(a) requires that the EPA Test Methods in 40 CFR Part 60, Appendices A-1 through A-8 and Appendix B be used except as provided in 40 CFR §60.8(b).

Adopted new §112.105(b) specifies the test methods to be used for testing the sulfur content of fuels. At adoption, the provision is expanded to include both fuel and waste gas, and the required test methods are changed based on comments on which tests are appropriate. Based on the EPA's comment that current versions of methods should be required, the date of each method added at adoption is not included and is removed for ASTM Method D1945 at adoption so that current versions can be used into the future. Because ASTM Method D5504 only detects all sulfur-containing compounds if the proper chromatograph analysis is tailored for all such compounds, language is added at adoption that this method can be used if conducted in an appropriate manner. Proposed ASTM Method D3588-93 is not included at adoption because Alon indicated that it is not appropriate for determining sulfur content.

Adopted new §112.105(c) provides the test method for testing the sulfur content in exhaust gases at the Alon USA Big Spring Refinery. The wording "United States Environmental Protection Agency" is used and the acronym is defined in the revised methods in §112.105(b), so the duplicate wording is deleted at adoption in §112.105(c) with only the acronym retained.

At adoption, a new §112.105(d) is added that specifies that flares must use the test methods and procedures in 40 CFR §60.104a, and the subsequent subsection is re-lettered accordingly. Adopted new §112.105(e), which was proposed as §112.105(d), allows the use of alternate methods after approval by the executive director and the EPA. This provision is intended to allow the approval of minor changes to the cited methods.

§112.106, Recordkeeping Requirements

The commission adopts new §112.106 to specify the records required to be maintained. Based on an EPA comment that the format must be specified, wording is added at adoption that the records must be in written or electronic format. Records are required to be kept for a minimum of five years. The records include all monitoring (including CEMS) data and sampling data (including sulfur content), the methods and calculations used to demonstrate compliance, documentation of any SO_2 exceedances, including root cause analyses, and the report submitted for these, and copies of required emission test data and records.

§112.107, Reporting Requirements

The commission adopts new §112.107(a) to specify the reporting required for each source covered by the rules. The required reports cover any exceedances of SO_2 emission limits and deviations from required stack parameters and must be submitted to the agency no later than March 31 of the year following the exceedance. The reports must include each occurrence date, an explanation of the exceedance and noncompliance with any required stack parameter, a statement of whether the exceedance or stack parameter noncompliance occurred during an authorized MSS activity for, or malfunction of, the emitting source or its control system, the actions taken in response to the exceedance or stack parameter noncompliance and the cause(s), and a certification of the accuracy and completeness of the report. A report is required regardless of whether the exceedance occurred from planned or unplanned events or during startup or shutdown and is also subject to the requirements of 30 TAC §101.211. If a reportable quantity (i.e., 500 pounds or more) of SO_2 is released, the provisions of §101.211 also apply, as do the reporting requirements for emissions events in §101.201 if the criteria therein are met. The reporting deadline of March 31 is intended to provide enough time for sites to determine the root cause of each exceedance to include in the report required by this section.

Adopted new §112.107(b) requires the owner or operator to submit results of emissions testing for determining compliance with the emission standards of SO_2 specified in adopted new §112.102(c)(1) to the appropriate TCEQ regional office and any local air pollution control agency having jurisdiction within 60 days after testing is complete and not later than the compliance schedule specified in §112.108.

The commission adopts new §112.107(c) as contingency measures if the EPA determines that the Howard County SO_2 nonattainment area does not achieve attainment on or after the attainment date. Based on a comment from the EPA, language is added at adoption to include triggering the contingency measure if the EPA determines that the nonattainment area failed to meet reasonable further progress (RFP). If the EPA makes such a determination, the TCEQ will notify the owner or operator of each company (including successors, if appropriate) of the determination and that these contingency measures are triggered. The owner or operator of each company notified must conduct a full system audit of all their sources covered in Division 1 and send a report of the results to the TCEQ executive director within 90 days of the notification from the TCEQ. The audit must include at a minimum a root cause analysis of the cause(s) of the failure to attain, including for the days that monitored exceedances occurred, a review of the hourly mass emissions from each SO_2 source, the wind speed and direction at the monitor with the NAAQS exceedance, and any emissions events that may have occurred. Based on comments that the basis for an EPA finding of failure to attain would affect the information that is useful in determining what contributed to the finding, wording is added at adoption to §112.107(c)(2) to clarify that review and consideration of meteorological data are only needed if the EPA's finding is based on ambient air monitor data or modeling data. To clarify what must be covered in an FSA in all cases from what must be covered only if the EPA's determination is based on ambient air monitor data or modeling data, the provisions are separated into §112.107(c)(2)(A) and (B), respectively. Additionally, based on comments, the term "exceptional event" is changed at adoption to "emissions event" for clarity. The provisions are included in the Reporting Requirements section of the rules because a report on the full system audit must be submitted to the executive director.

§112.108, Compliance Schedules

The commission adopts new §112.108 to specify the dates by which each source in §112.100 is required to comply with the requirements of Division 1. Based on input from Alon, the compliance date for the FCCU (EPN 06ESPPCV) and the SRU incinerators (EPN 69TGINC and EPN 71TGINC) is changed to November 1, 2023. The compliance date for the flares (EPN 14NEASTFLR. EPN 02CRUDEFLR, EPN 05REFMFLR, and 16SOUTHFLR) remains January 1, 2025, as proposed. At adoption, the phrase "as soon as practicable, but" is removed from before "no later than January 1, 2025" based on an EPA comment that the wording is not enforceable and other comment that the wording makes the actual compliance date uncertain.

DIVISION 2: REQUIREMENTS FOR THE TOKAI BIG SPRING CARBON BLACK PLANT

§112.110, Applicability

For sources at the Tokai Big Spring Carbon Black Plant that had contributions greater than the SIL, the emission rates are specified as an overall emissions cap, a cap for the two dryer stacks and individual limits for the incinerator, flare, and one of the dryer stacks at full load as well as emission limits for the same sources at reduced loads. To ensure that the tiered emissions caps at the Tokai Big Spring Carbon Black Plant will continue to model attainment, the TCEQ modeled a total of 192 operating scenarios accounting for different loads and operating conditions. In addition, for the situation where one or more of the Alon USA Big Spring Refinery's flares are intermittently in authorized MSS activities, multiple iterations of each of the 192 operating scenarios for the Tokai Big Spring Carbon Black Plant were conducted using a Monte Carlo simulation statistical approach. The emission rates included in the adopted rule modeled attainment under all 192 scenarios across a large number of Monte Carlo simulations. Additional information regarding the modeling analysis and determination of the adopted emission rates that demonstrate attainment is available in the concurrently adopted SIP revision for Howard County.

Instead of specifying the site by its RN as was proposed, the address of the site is added at adoption because the provision proposed as §112.112(a), which would have required approval for changing the RN, is removed at adoption. This will eliminate the need for a SIP revision if the RN changes.

Based on comments, the last sentence of §112.110(a) is removed. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA, which was the intent of the proposed language. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. After the EPA's approval, the rules are enforceable by both the EPA and the TCEQ. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

Adopted §112.110(b) identifies the sources affected by the rules by their name and EPN from the NSR permit for the site, with the order of the source name and EPN changed at adoption for consistency.

§112.111, Definitions

The commission adopts new §112.111 to define seven terms used in Division 2. The commission adopts new §112.111(1) to define block one-hour average which is used in the Tokai Big Spring Carbon Black Plant requirements. At adoption, a definition for continuous monitoring is added as new §112.111(2) based on an EPA comment. The subsequent definitions are renumbered. Adopted new §112.111(3), which was proposed as §112.111(2), defines the Howard County SO_2 nonattainment area; at adoption, the citation of the *Federal Register* publication is removed because it is not needed. Adopted new §112.111(4), which was proposed as §112.111(3), defines off-line for carbon black oil furnaces. Adopted new §112.111(5), which was proposed as §112.111(4), defines on-line for carbon black oil furnaces as not off-line. The commission proposed to define pipeline quality natural gas in proposed §112.111(5), but this definition is not needed and is removed at adoption based on an EPA comment. The commission adopts new §112.111(6) to define production unit as a combination of equipment used in the manufacture of carbon black at the Tokai Big Spring Carbon Black Plant because the term is used in the adopted rules only for that site, with distinction made between the production units associated with each EPN defined in this rule. At adoption, a sentence is added to the definition to clarify that tail gas not used for the dryers is burned in the Incinerator + HRSG (EPN 13A) or by Flare 4 (EPN Flare 4). Adopted new §112.111(7) defines tail gas for the carbon black plant.

§112.112, Control Requirements

The commission adopts new §112.112 to specify the control requirements for sources (designated through the relevant EPN) that were specified in §112.110. The emission rates established in the section are the rates that modeling shows demonstrate attainment in the concurrently adopted SIP revision for Howard County.

Proposed §112.112(a), which would have prohibited an owner or operator or any person acting for them from contravening the control requirements specified in these rules by changing the RN or EPN designation of any source without prior approval by the agency and the EPA, is removed at adoption based on public comment. The EPA stated that the only manner of approval for such a change would be a full SIP revision, which is overly burdensome. The subsequent subsections are re-lettered.

Adopted new §112.112(a), which was proposed as §112.112(b), provides the emission limits for sources at the Tokai Big Spring Carbon Black Plant, which has three carbon black production units: Production Unit 1 consists of five furnaces and three dryers; Production Unit 2 consists of four furnaces and two dryers; and Production Unit 3 consists of four furnaces and two dryers. Emissions of SO_2 associated with tail gas produced by Production Units 1 and 2 vent through EPN 7A, EPN 13A, or EPN FLARE 4. Emissions of SO_2 associated with tail gas produced by Production Unit 3 furnaces vent through EPNs12A, EPN 13A, or EPN FLARE 4. Emissions of SO_2 from all dryers associated with Production Units 1 and 2 vent through EPN 7A. Emissions of SO_2 from all dryers associated with Production Unit 3 vent through EPN 12A. Tail gas from the furnaces is also combusted in the Incinerator + HRSG (EPN 13A) and Flare 4 (EPN Flare 4). Based on a comment from Tokai that none of the production units can operate with only one furnace in operation, a prohibition is added at adoption to this subsection for the operation of a production unit with only one furnace operating, and the rows in the table in Figure 30 TAC §112.112(a) corresponding to a production unit operating with only one furnace are removed at adoption.

The table in adopted new Figure 30 TAC §112.112(a), which was proposed as Figure 30 TAC §112.112(b), provides emission limits for sources at maximum load and at reduced loads and includes overall emissions caps for all sources that can combust tail gas at the Tokai Big Spring Carbon Black Plant (carbon black dryers, Incinerator + HRSG, and flares) as well as emission limits for the two dryer stacks combined (EPN 7A and EPN 12A), emission limits for one individual dryer stack (EPN 12A), and emission limits for the incinerator or flare (EPN 13A). At the carbon black plant, operation at reduced loads is achieved by taking one or more furnaces off-line, which results in reduced dispersion of emissions and requires lower emission rates and associated stack parameters which could also result in less dispersion. To ensure attainment can be demonstrated under all operating conditions, the reduced load operating scenarios were also modeled. The table is used by selecting the row with the correct numbers in the first two columns for the numbers of furnaces operating in Production Units 1 and 2 and in Production Unit 3, respectively, and using the emission limit for each EPN in its corresponding column. For example, if there are two furnaces on-line in Production Unit 3, three furnaces on-line in Production Unit 1 and no furnaces on-line in Production Unit 2, the emission limits would be 519.42 lb/hr for the overall cap, 436.23 lb/hr for EPN 13A or Flare 4, 156.02 lb/hr for EPNs 7A and 12A combined, and 73.00 lb/hr for EPN 12A.

Adopted new §112.112(b), which was proposed as §112.112(c), is changed at adoption based on a comment from Tokai. Instead of requiring that the emission rate be based on only the fewest number of furnaces operating during an hour, a provision is added to allow calculating the emission rate based on the minute-by-minute changes in the number of furnaces operating. The change is made because Tokai indicated that using the fewest number of furnaces would result in no allowable emissions if all furnaces were shut down during an hour, but there would already have been emissions in that hour prior to the shutdown. Therefore, the adopted rule provides two options for determining the emission limits if the number of furnaces on-line during any one-hour period changes: under §112.112(b)(1), the fewest number of operating furnaces can be used to calculate the applicable reduction coefficient for use in determining the applicable emission limit; and under §112.112(b)(2), a time-weighted average of all limits applying during any part of an hour can be calculated using the equation in Figure 30 TAC §112.112(b)(2). This equation is based on the minute-by-minute changes in the number of furnaces operating during the hour.

The commission adopts new §112.112(c), which was proposed as §112.112(d), to specify that the determination of the maximum emission rate for each EPN is based on a block one-hour average. New §112.112(d) is added at adoption for clarity that the emission cap identified in Figure 30 TAC §112.112(a) is the maximum emission limit that applies to the sum of the emissions from EPN 13A, Flare 4, EPN 7A, and EPN 12A, as grouped in the columns of the table. The term “operational scenario” removed at adoption because it is not defined and is not necessary to identify all emission limits.

The commission adopts new §112.112(d) to provide more clarity on the use of the table in §112.112(a). Section 112.112(e), was proposed to prohibit the combustion of tail gas in any source or control device at the carbon black plant for which an allowable SO_2 emission rate is not specified because tail gas is high in sulfur compounds and was not represented in the modeling for other sources. At adoption, the phrasing is clarified to state that tail gas may only be combusted in a source whose emissions are routed to the EPNs represented in the attainment demonstration and the names of the sources rather than just the EPNs are identified. Adopted §112.112(f), prohibits the use of both the Incinerator + HRSG and Flare 4 during any block one-hour period, and adopted §112.112(g) prohibits routing of sulfur or sulfur containing compounds to Flare 1, Flare 2, or Flare 3 after the compliance date.

The commission adopts §112.112(h) to specify that the new flare, if authorized, must be constructed at a specific location, and must have a stack height of 60.35 meters, consistent with modeled parameters. At adoption, the wording "no less than" is removed from before the stack height based on EPA comment that changes to stack height require remodeling, and a typographical error is corrected by replacing the semicolon with a period at the end of the subsection.

Adopted §112.112(i) specifies that the Incinerator + HRSG must have a stack height of 65.00 meters, which is higher than the stack currently in place; based on an EPA comment that exceeding 65 meters requires their approval, the words "no less than" are removed from before the stack height at adoption. The attainment demonstration modeling showed that dispersion based on these stack heights was needed to avoid exceeding the NAAQS.

Adopted §112.112(j), which was proposed to allow the owner or operator to request an alternative SO_2 emission limit, is changed at adoption to reference new AMOC provisions that were submitted during the public comment period on this rule. The commission solicited comments on whether an additional mechanism to request alternative SO_2 emission limits, similar to AMOC provisions 30 TAC Chapter 115, Subchapter J, Division 1, are appropriate to include in Subchapter F. Based on a comment received from the EPA that the only approvable request for changing an emission limit is a full SIP revision, proposed §112.112(j) is not adopted as proposed but is instead changed to a provision allowing the submittal of an application for an AMOC. The provisions for AMOCs for Subchapter E are adopted as 112.102(i).

§112.113, Monitoring Requirements

Changes are made at adoption to §112.113(a) - (i) to require the owner or operator to conduct the monitoring specified. Adopted new §112.113(a) is changed at adoption to clarify that the calculations are to be done by each production unit by changing "from" to "by" and to require calculation of emissions from an individual production unit using the equation in Figure 30 TAC §112.113(a).

Adopted new §112.113(b) requires calculating actual emissions rates from each EPN subject to an emission limit under §112.112 using the equation in Figure 30 TAC §112.113(b), which is rewritten in a to account for the spilt of tail gas from each production unit instead of an average split across all units. Based on comments from the EPA, a typographical error in §112.113(b) is corrected by changing the second use of "EPN 13A" to "EPN 12A." At adoption, the proposed equation in proposed Figure is replaced with equations specific to each affected EPN in new paragraphs (1) - (4) added at adoption. New §112.113(b)(1) and Figure 30 TAC §112.113(b)(1) added at adoption provide for summing the total sulfur emissions from production units that are emitted as SO_2 by EPN 13A. New §112.113(b)(2) and Figure 30 TAC §112.113(b)(2) added at adoption provide for summing the total sulfur emissions from production units that are emitted as SO_2 by EPN 7A. New §112.113(b)(3) and Figure 30 TAC §112.113(b)(3) added at adoption provide for summing the total sulfur emissions from production units that are emitted as SO_2 by EPN Flare 4. New §112.113(b)(4) and Figure 30 TAC §112.113(b)(4) added at adoption provide for calculating the total sulfur emissions from Production Unit 3 that are emitted as SO_2 by EPN 13A.

Adopted new §112.113(c) requires the installation, use, calibration, and maintenance of totalizing fuel flow meters for carbon black oil entering each production unit. At adoption, wording is added to specify that the installation, use, calibration, and maintenance must be consistent with the manufacturer's specifications for the meter. Adopted new §112.113(d) requires the installation, use, calibration, and maintenance of totalizing fuel flow meters for tail gas for all combustion sources or control devices using this fuel. At adoption, wording is added for clarity to specify that the installation, use, calibration, and maintenance must be consistent with the manufacturer's specifications for the meter and that the combustion units that burn tail gas include the dryers, the Incinerator + HRSG (EPN 13A), and Flare 4 (EPN Flare 4).

Adopted new §112.113(e) requires the use of a continuous monitoring and data acquisition system to continuously measure, calculate, and record the quantities specified in §112.113(e)(1) - (3), with wording changes made at adoption throughout the subsection for clarity. Adopted §112.113(e)(1) specifies the volumetric flow rate of tail gas to Incinerator + HRSG and Flare 4 (EPNs 13A and Flare 4), with wording added at adoption to require tracking the data from each production unit separately. Adopted §112.113(e)(2) specifies the volumetric flow rate of tail gas to the carbon black dryers in each production unit; at adoption, the requirement is changed from tracking the data for each dryer separately. Adopted §112.113(e)(3) specifies the volumetric flow rate of tail gas from each production unit; the provision is changed at adoption from tracking the flow to all dryers. Proposed §112.113(e)(4), which specified tracking the aggregate tail gas flow rate to all combustion devices, is removed at adoption because the data is not needed for the calculation, and the subsequent paragraphs are renumbered. Adopted §112.113(e)(4), which was proposed as §112.113(e)(5), specifies the ratio of the quantities in paragraphs (1) and (3) as variable "π_{incin}", with changes made at adoption to specify that the data points are for each production unit and to remove the citation to paragraph (4) that is removed at adoption. Adopted §112.113(e)(5), which was proposed as §112.113(e)(6), specifies the ratio of the quantities in paragraphs (2) and (3) as variable "π_{dryer}", with changes made at adoption to specify that the data points are for each production unit and to remove the citation to paragraph (4) that is removed at adoption. The variables defined as these ratios are used to establish the split coefficients applied to emissions from the production units to estimate the emissions from each stack.

The commission adopts §112.113(f) to require that the continuous data acquisition system be installed, calibrated, maintained, and operated in accordance with manufacturer's recommended procedures. A change is made at adoption to correct the citation for the data acquisition system to §112.113(e).

The commission adopts new §112.113(g) to require measurement of the sulfur content of carbon black oil feedstock fed to each of the carbon black production units. At adoption, the frequency of the measurements is changed from daily to twice daily (at least four hours apart) based on an EPA comment that daily monitoring is insufficient.

Adopted new §112.113(h) requires daily measurement of the sulfur content by weight of each grade of carbon black produced from each carbon black production unit, with a change made at adoption to improve phrasing. Adopted new §112.113(i) requires the determination of the amount of each grade of carbon black produced in each production unit, with a change made at adoption to clarify that the determination must be made during each hour. The term "determine" was used instead of "measure" because this number may be calculated from other parameters as opposed to being directly measured as it may be difficult to measure hourly production rates.

Adopted new §112.113(j) allows for the use of a CEMS to directly monitor emission in lieu of a mass balance approach for determining emissions. Adopted new §112.113(k), proposed as §112.113(j), requires the use of an appropriate QA/QC process to validate continuous monitoring data for at least 95% of the time the monitored emissions point has emissions; use of an appropriate data substitution process, which is the most accurate method available, must be used to obtain all missing or invalidated monitoring data for the emissions point.

A new provision is added at adoption as §112.113(l) based on comments to allow the executive director of the agency to approve minor modifications of monitoring methods. As in the similar provision in 30 TAC §115.725(m), executive director approval and validation of the modified method using 40 CFR Part 63, Appendix A, Test Method 301, as applicable, is required for a modified monitoring method to be used. The language specifies that minor modifications include increases of the frequency of monitoring provided the quality control, quality assurance, and data validation requirements and accuracy specifications are specified and are at least as stringent as required in the rules.

§112.114, Testing Requirements

Changes are made at adoption to §112.114(a), (b), and (d) to require the owner or operator to do the testing specified. The commission adopts new §112.114(a) to require initial demonstration of compliance testing for sources combusting tail gas, except for flares, and a change is made at adoption to require that the owner or operator perform additional demonstrations of compliance at least every five years. Adopted new §112.114(b) requires that this testing be done using the test methods in adopted new §112.115. Adopted new §112.114(c) specifies that for performance tests the source must be operated as close to its maximum rated capacity as practicable. Adopted new §112.114(d) requires that additional performance testing be done if requested by the executive director using specified federal methods and criteria in the test methods in adopted new §112.115. Adopted new §112.114(e) specifies that performance testing every five years is not required if a CEMS is used to monitor emissions.

§112.115, Approved Test Methods

The commission adopts new §112.115 to specify the test methods required to comply with the testing requirements in adopted new §112.114. The test methods relate to the testing requirements in adopted new §112.114. Adopted new §112.115(a) requires that the EPA Test Methods in 40 CFR Part 60, Appendices A-1 through A-8 and Appendix B be used except as provided in 40 CFR §60.8(b).

Adopted new §112.115(b) specifies the test methods to be used for testing the sulfur content of fuels and carbon black oil. Based on an EPA comment that the most current versions of test methods should be referenced, the date references in the cited test method designations are removed at adoption so that the most current version can be used into the future. Based on input from Tokai, ASTM Method D4294 is added at adoption and Method D3588-93 is removed. Adopted new §112.115(c) provides the test method for testing the sulfur content of carbon black product. Adopted new §112.115(d) provides the test method for determining the sulfur content in exhaust gases at the Tokai Big Spring Carbon Black Plant. At adoption, a new §112.115(e) is added for consistency with the rules in the other divisions, and the subsequent subchapter is re-lettered. The added §112.115(e) requires that the owner or operator use the flare test methods and procedures in 40 CFR §60.104a even though those provisions do not apply to the flares at the Tokai Big Spring Carbon Black Plant.

Adopted new §112.115(f), which was proposed as §112.115(e), allows the use of alternate methods after approval by the executive director and the EPA. This provision is intended to also allow the approval of minor changes to the cited methods.

§112.116, Recordkeeping Requirements

The commission adopts new §112.116 to specify the records required to be maintained for at least five years at the Tokai Big Spring Carbon Black Plant. Based on an EPA comment that the format must be specified, wording is added at adoption to require the records in written or electronic format. Adopted new §112.116(1) requires records by production unit of the production rates (as lb/hr) of the different grades of carbon black by each production unit.

Adopted new §112.116(2) requires records of the sulfur content by weight of the carbon black oil feedstock; based on input from Tokai, the frequency of the records is increased at adoption from daily to twice daily. Adopted new §112.116(3) requires daily records of the sulfur content by weight of each grade of carbon black produced by each production unit. Adopted new §112.116(4) requires continuous records of flow rates of the carbon black oil feedstock to each production unit. Adopted new §112.116(5) requires continuous records of volumetric flow rates to each tail gas combustion device.

Adopted new §112.116(6) requires for each one-hour block of operation of each production unit, records be maintained of each furnace that operated, the applicable emission limits, and the mass balance calculations for each EPN, including the relevant factors used in the calculations. At adoption, changes are made in subparagraphs §112.116(6)(A) - (C). In §112.116(6)(A), the frequency requirement for recording the identity of each furnace on-line is changed from "during the block one-hour period" to "each minute of each block one-hour period" because of the changes made at adoption in §112.112(b) for determining emission limits based on the minute-by-minute changes in the number of furnaces operating. In §112.116(6)(B), a clause is added at adoption to require records of the calculations in adopted §112.112(b). For completeness in §112.116(6)(C), the monitoring records are expanded to include all information identified in §112.113 rather than only the factors used in calculating actual emissions.

Adopted new §112.116(7) requires maintaining records of all exceedances of emission limits and standards in the rules and copies of the exceedance reports filed under §112.117. New §112.116(8) is changed at adoption for clarity to require maintaining copies of reports of all tests conducted under §112.114 rather than records of all required emissions test data and records. These records are sufficient to determine compliance with then rule requirements but are less burdensome for Tokai.

§112.117, Reporting Requirements

The commission adopts new §112.117(a) to specify the reporting required for each source covered by the rules. The required reports cover any exceedances of SO_2 emission limits and deviations from required stack parameters; must be submitted to the agency no later than March 31 of the year following the exceedance; and must include each occurrence date, an explanation of the exceedance and noncompliance with any required stack parameter, a statement of whether the exceedance or stack parameter noncompliance occurred during an authorized MSS activity for, or malfunction of, the emitting source or its control system, the actions taken in response to the exceedance or stack parameter noncompliance and the cause(s), and a certification of the accuracy and completeness of the report.

A report is required regardless of whether the exceedance occurred from planned or unplanned events or during startup or shutdown and is also subject to the requirements of 30 TAC §101.211. If a reportable quantity (i.e., 500 pounds or more) of SO_2 is released, the provisions of §101.211 also apply, as do the reporting requirements for emissions events in §101.201 if the criteria therein are met. The reporting deadline of March 31 is intended to provide enough time for sites to determine the root cause of each exceedance to include in the report required by this section.

Adopted new §112.117(b) requires the owner or operator to submit results of emissions testing for determining compliance with the emission standards of SO_2 specified in adopted new §112.112(b) to the appropriate TCEQ regional office and any local air pollution control agency having jurisdiction within 60 days after testing is complete and not later than the compliance schedule specified in §112.118.

The commission adopts new §112.117(c) as contingency measures if the EPA determines that the Howard County SO_2 nonattainment area does not achieve attainment on or after the attainment date; based on a comment from the EPA, language is added at adoption throughout the subsection to include triggering the contingency measure if the EPA determines that the nonattainment area failed to meet RFP. If the EPA makes such a determination, the TCEQ will notify the owner or operator of each company (including successors, if appropriate) of the determination and that these contingency measures are triggered. The owner or operator of each company must conduct a full system audit of all their sources covered in this division and send a report of the results to the TCEQ executive director within 90 days of the notification from the TCEQ. The audit must include at a minimum a root cause analysis of the cause(s) of the failure to attain, including for the days that monitored exceedances occurred, a review of the hourly mass emissions from each SO_2 source, the wind speed and direction at the monitor with the NAAQS exceedance, and any emissions events that may have occurred. Based on comments that the basis for an EPA finding of failure to attain would affect the information that is useful in determining what contributed to the finding, wording is added at adoption to §112.117(c)(2) to clarify that review and consideration of meteorological data are only needed if the EPA's finding is based on ambient air monitor data or modeling data. To clarify what must be covered in an FSA in all cases from what must be covered only if the EPA's determination is based on ambient air monitor data or modeling data, the provisions are separated into §112.117(c)(2)(A) and (B), respectively. Additionally, based on comments, the term "exceptional event" is changed at adoption to "emissions event" for clarity. The provisions are included in the Reporting Requirements section of the rules because a report on the full system audit must be submitted to the executive director.

§112.118, Compliance Schedules

The commission adopts new §112.118 to specify the date by which each source in §112.110 are required to comply with the requirements of Division 2. At adoption, the phrase "as soon as practicable, but" is removed from before "no later than January 1, 2025" based on an EPA comment that the wording is not enforceable and another comment that the wording makes the actual compliance date uncertain.

SUBCHAPTER F, REQUIREMENTS IN THE HUTCHINSON COUNTY NONATTAINMENT AREA

Division 1, Requirements for the Chevron Phillips Chemical Borger Plant

§112.200, Applicability

The commission adopts new §112.200 to specify that the new rules apply to sources at the CP Chem Borger Plant at which the agency has determined emissions contribute to potential exceedances of the 2010 SO_2 NAAQS based on modeling conducted for the concurrently adopted SIP revisions discussed elsewhere in this preamble. The adopted rule provisions in new Division 1 are site-specific as identified by the current name and the latitude/longitude coordinates. The latitude/longitude coordinates of the site are added in §112.200(a) at adoption to replace the provision proposed as §112.202(a), which would have required approval for changing the RN. This will eliminate the need for a SIP revision if the RN changes.

The adopted rules are also EPN specific and specified by the current names of affected existing sources and their EPNs as documented in a specified version of the NSR permit or the name and EPN used in attainment demonstration modeling for the fugitive sources. The adopted requirements will continue to apply regardless of any changes of ownership, control, or documentation of the affected sources.

Based on comments, the last sentence of §112.200(a) is removed. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA, which was the intent of the proposed language. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. After the EPA's approval, the rules are enforceable by both the EPA and the TCEQ. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

The TCEQ conducted attainment demonstration modeling for sources in the Hutchinson County nonattainment area using the emission rates (during normal operations and, when applicable, during authorized MSS activity) from the NSR permit for each site or lower emission rates if needed to demonstrate attainment as well as emission rates provided by the company for sources to be constructed. As discussed elsewhere in this preamble, the owners and operators of the five sites in the

Hutchinson County SO_2 nonattainment area committed to lowering emission rates. The lower emission rates were the rates used in the attainment demonstration modeling, which also used stack parameters supplied for each emissions point. Modeling was conducted to determine which specific emissions points have emissions that contribute greater than the SIL of 3 ppb (i.e., 7.85 $\mu g/m^3$) to the modeled design value concentrations at any receptor in the Hutchinson County SO_2 nonattainment area. If the emissions point had a contribution to the modeled design value that was less than the SIL, it is not included in the rules. If the emission point had a contribution to the modeled design value that was greater than the SIL, its emission rates are specified in the rules. When modeled collectively with all emissions sources in the nonattainment area, the emission rates specified in the rule resulted in modeled design values below the NAAQS.

§112.201, Definitions

The commission adopts new §112.201 to define three terms used in Division 1. The commission adopts new §112.201(1) to define block one-hour average. At adoption, a definition for continuous monitoring is added as new §112.201(2) based on an EPA comment. The subsequent definition is renumbered. Adopted new §112.201(3), which was proposed as §112.201(2), defines the Hutchinson County SO_2 nonattainment area; at adoption, the citation of the *Federal Register* publication is removed because it is not needed. The commission proposed the prior §112.201(3) to define pipeline quality natural gas, but this definition is not needed and is removed at adoption based on an EPA comment.

§112.202, Control Requirements

Proposed §112.202(a), which would have prohibited the owner or operator of the CP Chem Borger Plant from contravening the control requirements by changing the EPN designation of any emissions point without prior approval by the agency and the EPA, is removed at adoption based on public comment. The EPA stated that the only manner of approval for such a change would be a full SIP revision, which is overly burdensome. The subsequent subsections are re-lettered.

Adopted new §112.202(a), which was proposed as §112.202(b), provides the emission limits for the two sulfolene handling areas. Although the fugitive emissions for sulfolene areas are authorized under the single EPN (F-M2A) in NSR permit 21918, the two areas where the emissions originate were modeled separately and have separate emission rates when modeling attainment. Adopted new §112.202(a)(1) limits the sulfolene building and the trailers in its vicinity (EPN F-M2A_1 in the modeling) to 0.98 lb/hr SO_2. Adopted new §112.202(a)(2) limits the trailers in parking area (EPN F-M2A_2 in the modeling) to 1.00 lb/hr SO_2. The limits for the two areas are switched at adoption from the values proposed because the attainment demonstration modeling used 1.0 lb/hr for the sulfolene handling building and trailers at that location and 0.98 lb/hr for the trailer storage area and because CP Chem indicated that the adopted limits are consistent with their calculations of the maximum emissions for each area.

Adopted new §112.202(b), which was proposed as §112.202(c), limits the North Flare

(EPN FL-1) and South Flare (EPN FL-2) to a combined total of 430.00 lb/hr. Although the EPA commented that individual limits for the flares should be provided in the rule, attainment demonstration modeling shows that each flare emitting at the cap rate achieves attainment, so individual limits are not needed.

Adopted new §112.202(c) which was proposed as §112.202(d) to allow the owner or operator to request an alternative SO_2 emission limit, is changed at adoption to reference AMOC provisions that were submitted during the public comment period on this rule. The commission solicited comments on whether an additional mechanism to request alternative SO_2 emission limits, similar to the AMOC provisions 30 TAC Chapter 115, Subchapter J, Division 1, are appropriate to include in Subchapter F. CP Chem and several commenters supported adopting AMOC provisions in lieu of the alternative SO_2 emission limits text. Comments provided by Phillips 66 provided detailed AMOC language that is incorporated in new §112.232(k). Based on a comment received from the EPA that the only approvable request for changing an emission limit is a full SIP revision, proposed §112.202(d) is not adopted as proposed but is instead changed to a provision allowing the submittal of an application for an AMOC. The provisions for AMOCs are adopted as new §112.232(k) and are cross-referenced in the adopted version of new §112.202(c). The specific AMOC rule text is adopted in Division 4 because P66 provided the draft language in their comments.

§112.203, Monitoring Requirements

At adoption, the wording “the owner or operator shall” is added to §112.203(a) - (c) to clarify that the requirements apply to the owner or operator. Adopted new §112.203(a) requires the owner or operator of the CP Chem Borger Plant to monitor each hour the temperature inside of the sulfolene handling building and trailers on site that contain sulfolene, which decomposes when exposed to heat and is stored in trailers on site prior to transport. Because the equation provided by CP Chem requires the weight of sulfolene as well as a decomposition factor based on temperature and time, the weight of sulfolene stored in the sulfolene handling building and each trailer and the times the sulfolene was stored are added at adoption to the monitoring required in §112.203(a), as well as the temperature in the sulfolene handling building.

The adopted limits are based on new testing conducted at specific temperatures that provided the equations for calculating the weight of SO_2 emissions and the percentage of decomposition of sulfolene that were provided by CP Chem, which are provided in Figure 30 TAC §112.203(a)(1) and Figure 30 TAC §112.203(a)(2), respectively. The decomposition of sulfolene varies by both its temperature and the number of hours at that temperature. The equation for the percentage of decomposition was determined by CP Chem by plotting the results of a study conducted by CP Chem in 2021 and fitting the results to a three-dimensional surface, then determining the equation that gave the best “goodness of fit” to the data, which is the sigmoidal equation in Figure 30 TAC §112.203(a)(2). The percentage of decomposition calculated and the weight of sulfolene stored are entered into the equation in Figure 30 TAC §112.203(a)(1) to give the SO_2 emissions. The calculation is conservative because of two factors: the total weight loss from the sulfolene in the study was used in determining the sigmoidal equation, but 45.8% of weight loss is from the butadiene component rather than the SO_2; and the monitored ambient temperature in the sulfolene handling building or trailer is assumed to have been transferred equally throughout the sulfolene in that area. A higher ambient temperature will take time to heat the sulfolene, but the heat from the sulfolene will keep the monitored temperature higher when the temperature outside the area falls. To demonstrate compliance, paragraphs (3) - (5) added at adoption for clarity specify that the emissions from the sulfolene handling building and each trailer are calculated first and are then summed for each area.

New adopted §112.203(b) requires the owner or operator to monitor separately the sulfur content of gases routed to the North and South Flares (EPN FL-1 and EPN FL-2). The monitors are specified to be analyzers sufficient to quantify the total sulfur content at a level of 1 part per million by volume (ppmv). At adoption, a provision is added that the meters must be installed, calibrated, maintained, and operated according to the manufacturer's specifications. The commission requested public comment on whether the level of accuracy and downtime is appropriate for a monitor for this function. CP Chem provided comment with an alternate level of accuracy requirement, which is added to the rule in place of the detection limit that was proposed. Additionally, CP Chem provided input that a *de minimis* amount of SO_2 was detected in one sample of gas sent to the South Flare but that the CP Chem Borger Plant's monitor does not detect SO_2. To compensate, CP Chem committed to adding 0.015 lb/hr SO_2 to each hourly calculated emission to the South Flare, which equates to ten times the highest amount tested at the maximum flow rate to the flare. This addition is included in the revised adopted calculation in §112.203(b).

New adopted §112.203(c) requires the owner or operator to monitor separately the volumetric flow rate of gases routed to the North and South Flares. The gas flow monitors are required to be totalizing gas flow meters with an accuracy of ±5% that are installed, maintained, calibrated, and operated according to the manufacturer's specifications. The commission requested public comment on whether the level of accuracy and downtime is appropriate for a monitor for this function, but no comments were received. This data from the monitoring in subsections (b) and (c) allow determination of the SO_2 emissions from the flares. At adoption the phrase "manufacturer's directions" is changed to "manufacturer's specifications" for clarity.

New §112.203(d) is added at adoption to provide an equation for calculating SO_2 emissions from each flare. In the calculations, the inlet sulfur compound concentration is multiplied by the waste gas flow rate and by factors to convert from ambient to standard conditions. The subsequent subsection is re-lettered.

Adopted new §112.203(e), proposed as §112.203(d), requires the use of an appropriate QA/QC process to validate continuous monitoring data for at least 95% of the time the monitored emissions point has emissions. An appropriate data substitution process, which is the most accurate method available and at least equivalent to engineering judgment, must be used to obtain all missing or invalidated monitoring data for the emissions point.

A new provision is added at adoption as §112.203(f) based on comments to allow the executive director of the agency to approve minor modifications of monitoring methods. As in the similar provision in 30 TAC §115.725(m), executive director approval and validation of the modified method using 40 CFR Part 63, Appendix A, Test Method 301, as applicable, is required for a modified monitoring method to be used. The language specifies that minor modifications include increases of the frequency of monitoring and replacements of parametric monitoring with a CEMS provided the quality control, quality assurance, and data validation requirements and accuracy specifications are specified and are at least as stringent as required in the rules.

There are no specific testing requirements for the CP Chem Borger Plant, and therefore no specific test methods. To maintain consistency in the numbering in the divisions within the adopted new rules, the corresponding sections are skipped in Division 1. Although the EPA commented that these sections are needed, there is no ongoing testing needed for monitoring the sulfolene fugitive emissions or the flares. The testing was already done to establish the equation to calculate the fugitive emissions and further testing is not needed.

§112.206, Recordkeeping Requirements

The commission adopts new §112.206 to specify the records required to be maintained. Based on EPA comment that the format must be specified, wording is added at adoption that the records must be in written or electronic format. All records are required to be maintained for at least five years.

At adoption, changes are made to new §112.206(1) based on EPA comment that monitoring and recordkeeping should be on an hourly basis to add additional hourly recordkeeping provisions for the changes made to monitoring for the sulfolene areas. The records requirements are placed in new §112.206(1)(A) - (G) for readability and clarity. New §112.206(1)(A) requires that the owner or operator maintain hourly records of the temperature inside the sulfolene handling building and each trailer that contains sulfolene. New §112.206(1)(B) requires that the owner or operator record the amount of sulfolene in the sulfolene handling building and each trailer during each hour and the time and weight of sulfolene transferred to each trailer. New §112.206(1)(C) requires that the owner or operator record whether each trailer is located near the sulfolene building (modeled as F-M2A_1) or in the trailer parking area (modeled as F-M2A_2). Because the filled trailers are moved from the vicinity of the sulfolene handling building to the trailer storage area and are afterwards shipped offsite from the trailer storage area, hourly records of the location of each trailer are needed for accurate calculations of emissions. New §112.206(1)(D) requires that the owner or operator record separately the SO_2 emissions from the sulfolene handling building and each trailer. New §112.206(1)(E) requires that the owner or operator record the summed SO_2 emissions from the sulfolene handling building and the adjacent trailers. New §112.206(1)(F) requires that the owner or operator record the summed SO_2 emissions from the trailer parking area.

For the attainment demonstration modeling, the company represented that two trailers are at the sulfolene building and six trailers are in the trailer parking area, but there is no limit placed on the number of trailers at either location because the fugitive emissions depend on the amount of sulfolene present and its temperature. The company performed testing to establish the emission rates based on temperature and the amount of weight loss over time for the sulfolene storage that was used in the attainment demonstration modeling to determine the emission rates included in the adopted rules. Using the ambient temperature inside the building and each trailer (which elevates the temperature of the sulfolene more slowly) and using the full weight loss (including the butadiene weight loss) from the sulfolene during testing both make the calculations very conservative and therefore protective of the NAAQS.

Adopted new §112.206(2) requires that the company maintain records of the sulfur content and flow rates of gases sent to the flares and the emission rates calculated from this monitoring as well as the periods of time that each flare was in use. The records of the sulfur content and flow rates of gases sent to the flares, the calculated emissions, and the periods of time that each flare was in use are sufficient to document compliance with the emission limits for each control device.

At adoption, a new §112.206(3) is added to require maintaining documentation of any exceedances of emission limits or standards and copies of all exceedance reports submitted to the appropriate regional office. The provision is added to be consistent with the requirements for other sites.

§112.207, Reporting Requirements

The commission adopts new §112.207(a) to specify the reporting to TCEQ Region 1 required for the CP Chem Borger Plant if an affected emissions point exceeds an applicable emission limit or fails to meet a required stack parameter. The reports are due by March 31 of the year following the year in which the exceedance or failure to meet a required stack parameter occurs. The reports are required to include at a minimum: the date of, and an explanation of, each exceedance and noncompliance with any required stack parameter; whether the exceedance or stack parameter noncompliance was concurrent with an authorized MSS activity for, or a malfunction of, the source or control device; the actions taken by the owner or operator to address the exceedance or stack parameter noncompliance and the cause(s); and a certification that the information provided is accurate.

A report is required regardless of whether the exceedance occurred from planned or unplanned events or during startup or shutdown. If a reportable quantity (500 pounds or more) of SO_2 is released, the provisions of §101.211 also apply, as do the reporting requirements for emissions events in §101.201 if the criteria therein are met. The reporting deadline of March 31 is intended to provide enough time for sites to determine the root cause of each exceedance to include in the report required by this section.

Because CP Chem did not provide a way to monitor the fugitive emissions from the sulfolene areas prior to proposal, §112.207(b) was proposed to require the owner or operator to file the exceedance report in subsection (a) annually and to include the hourly monitoring of temperatures inside the trailers containing sulfolene, highlighting any periods when the temperature exceeded 125 degrees Fahrenheit. However, because CP Chem provided documentation of its study used to establish the modeled emission limits for the fugitive emissions, which was used to establish the monitoring and recordkeeping provisions added at adoption, §112.207(b) is removed at adoption. The exceedance report in §112.207(a) will only need to be filed if there is an exceedance. The subsequent subsection is re-lettered.

The commission adopts new §112.207(b), which was proposed as §112.207(c), as contingency measures if the EPA determines that the Hutchinson County SO_2 nonattainment area does not achieve attainment on or after the attainment date; based on a comment from the EPA, language is added at adoption to include triggering the contingency measure if the EPA determines that the nonattainment area failed to meet RFP. If the EPA makes such a determination, the TCEQ will notify the owner or operator of each company (including successors, if appropriate) subject to Subchapter F of the determination and that these contingency measures are triggered. The owner or operator of each company must conduct a full system audit of all their sources subject to Subchapter F and send a report of the results to the TCEQ executive director within 90 days of the notification from the TCEQ. The audit must include at a minimum a root cause analysis of the cause(s) of the failure to attain, including for the days that monitored exceedances occurred, a review of the hourly mass emissions from each SO_2 source, the wind speed and direction at the monitor with the NAAQS exceedance, and any emissions events that may have occurred. Based on comments that the basis for an EPA finding of failure to attain would affect the information that is useful in determining what contributed to the finding, wording is added at adoption to §112.207(c)(2) to clarify that review and consideration of meteorological data are only needed if the EPA's finding is based on ambient air monitor data or modeling data. To clarify what must be covered in an FSA in all cases from what must be covered only if the EPA's determination is based on ambient air monitor data or modeling data, the provisions are separated into §112.207(c)(2)(A) and (B), respectively. Additionally, based on comments, the term "exceptional event" is changed at adoption to "emissions event" for clarity. The provisions are included in the Reporting Requirements section of the rules because a report on the full system audit must be submitted to the executive director.

§112.208, Compliance Schedule

The commission adopts new §112.208 to specify the date by which each source identified in §112.200 is required to comply with the requirements of Division 1. At adoption, the phrase "as soon as practicable, but" is removed from before "no later than January 1, 2025" based on an EPA comment that the wording is not enforceable and another comment that the wording makes the actual compliance date uncertain.

DIVISION 2, REQUIREMENTS FOR THE IACX ROCK CREEK GAS PLANT

§112.210, Applicability

The commission adopts new §112.210 to specify that the new rules apply to sources at the IACX Rock Creek Gas Plant at which the agency has determined emissions contribute to the potential exceedances of the 2010 SO_2 NAAQS based on modeling conducted for the concurrently adopted SIP revisions discussed elsewhere in this preamble. The adopted rule provisions in new Division 2 are site-specific and specified by the current name and address of the site. This will eliminate the need for a SIP revision if the RN changes. The adopted rules are also EPN specific and specified by the current names of affected existing sources and their EPNs as documented in a specified version of the NSR permit or the name and EPN used in attainment demonstration modeling for sources to be authorized and constructed. The adopted requirements will continue to apply regardless of any changes of ownership, control, or documentation of the affected sources.

Based on comments, the last sentence of §112.210(a) is removed. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA, which was the intent of the proposed language. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. After the EPA's approval, the rules are enforceable by both the EPA and the TCEQ. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

The TCEQ conducted attainment demonstration modeling for sources in the Hutchinson County nonattainment area using the emission rates (during normal operations and, when applicable, during authorized MSS activities) from the NSR permit for each site or lower emission rates if needed to demonstrate attainment as well as emission rates provided by the company for sources to be constructed. As discussed elsewhere in this preamble, the owners and operators of the five sites in the Hutchinson County SO_2 nonattainment area committed to lowering emission rates. The lower emission rates were the rates used in the attainment demonstration modeling, which also used stack parameters supplied for each emissions point. Modeling was conducted to determine which specific emissions points have emissions that contribute greater than the SIL of 3 ppb (i.e., 7.85 $\mu g/m^3$) to the modeled design value concentrations at any receptor in the Hutchinson County SO_2 nonattainment area. If the emissions point had a contribution to the modeled design value that was less than the SIL, it is not included in the rules. If the emissions point had a contribution to the modeled design value that was greater than the SIL, its emission rates are specified in the rules. When modeled collectively with all emissions sources in the nonattainment area, the emission rates specified in the rule resulted in modeled design values below the NAAQS.

§112.211, Definitions

The commission adopts new §112.211 to define three terms used in Division 2. The commission adopts new §112.211(1) to define block one-hour average. At adoption, a definition for continuous monitoring is added as new §112.211(2) based on an EPA comment. The subsequent definition is renumbered. Adopted new §112.211(3), which was proposed as §112.211(2), defines the Hutchinson County SO_2 nonattainment area; at adoption, the citation of the *Federal Register* publication is removed because it is not needed. The commission proposed the prior §112.211(3) to define pipeline quality natural gas, but this definition is not needed and is removed at adoption based on an EPA comment.

§112.212, Control Requirements

Proposed §112.212(a), which would have prohibited the owner or operator of the IACX Rock Creek Gas Plant from contravening the control requirements by changing the EPN designation of any emissions point without prior approval by the agency and the EPA, is removed at adoption based on public comment. The EPA stated that the only manner of approval for such a change would be a full SIP revision, which is overly burdensome. The subsequent subsections are re-lettered.

Adopted new §112.212(a), which was proposed as §112.212(b), prohibits operating the acid gas flare and incinerator at the same time. Emission limits are adopted for the acid gas flare (EPN FLR1) in §112.212(b), which was proposed as §112.212(c), as 140.00 lb/hr and the acid gas incinerator (EPN INCIN1) in §112.212(c), which was proposed as §112.212(d), as 140.00 lb/hr. The term “sulfur dioxide” is added before the acronym “SO_2” in §112.212(b) at adoption for clarity.

Adopted new §112.212(d), which was proposed as §112.212(e) to allow the owner or operator to request an alternative SO_2 emission limit, is changed at adoption to reference AMOC provisions that were submitted in the comments from Phillips 66. The commission solicited comments on whether an additional mechanism to request alternative SO_2 emission limits, similar to the AMOC provisions 30 TAC Chapter 115, Subchapter J, Division 1, are appropriate to include in Subchapter F. Based on a comment received from the EPA that the only approvable request for the change is a full SIP revision, proposed §112.212(e) is not adopted as proposed but is instead changed to a provision allowing the submittal of an application for an AMOC. The provisions for AMOCs are adopted as new §112.232(k) and cross-referenced in §112.212(d). The specific AMOC rule text is adopted in Division 4 because Phillips 66 provided the draft language in Phillips 66's comments.

§112.213, Monitoring and Testing Requirements

Because new provisions are added at adoption as new subsections, the proposed monitoring requirements are recodified as subsection (a), testing requirements are added as subsection (b), and approved test methods are added as subsection (c). New §112.213(a)(1) and (2) were proposed to require the owner or operator of the IACX Rock Creek Gas Plant to continuously monitor and record the H_2S content and flow rate of gases routed to the acid gas incinerator or acid gas flare, which cannot be used at the same time. Based on the company's request to avoid the need for duplicate monitors, the monitoring was proposed to occur prior to the point where the piping splits to lead to each control device. Because the waste gases contain organic sulfur compounds as well as H_2S, the monitoring requirements are changed at adoption. The specification that the monitoring occurs before where the piping splits is moved to the introductory paragraph of new subsection (a), and two options for monitoring the sulfur content of the waste gases are provided, which are the same as the options provided for the Alon USA and Phillips 66 refineries. An option to use a monitor for total sulfur content is adopted as §112.213(a)(1)(A), including an equation in Figure 30 TAC §112.213(a)(1)(A) to calculate the SO_2 emissions. An option to monitor for H_2S as a surrogate for total sulfur content is adopted as §112.213(a)(1)(B), including an equation in Figure 30 TAC §112.213(a)(1)(B) to calculate the SO_2 emissions. Each monitor is specified to be an analyzer with an accuracy of ±5% on a continuous basis.

At adoption in §112.213(a)(2), "per" is changed to "according to" and "directions" is changed to "specifications" for clarity. The gas flow monitor is required to be a totalizing gas flow meter with an accuracy of ±5% that is installed, maintained, and calibrated according to the manufacturer's specifications. A new §112.213(a)(3) is added at adoption to require monitoring the temperature of the waste gases because those data are needed for the calculations of SO_2 emissions in §112.213(a)(1)(A) and (B). Adopted new §112.213(a)(4) allows for the use of a CEMS to directly monitor the emissions from the incinerator in lieu of monitoring flow rate and to total sulfur or H_2S concentration. Adopted new §112.213(a)(5), which was proposed as §112.213(3), requires the use of an appropriate QA/QC process to validate continuous monitoring data for at least 95% of the time the monitored emissions point has emissions; use of an appropriate data substitution process, which is the most accurate method available, must be used to obtain all missing or invalidated monitoring data for the emissions point.

A new provision is added at adoption as §112.213(a)(6) based on comments to allow the executive director of the agency to approve minor modifications of monitoring methods. As in the similar provision in 30 TAC §115.725(m), executive director approval and validation of the modified method using 40 CFR Part 63, Appendix A, Test Method 301, as applicable, is required for a modified monitoring method to be used. The language specifies that minor modifications include increases of the frequency of monitoring provided the quality control, quality assurance, and data validation requirements and accuracy specifications are specified and are at least as stringent as required in the rules.

Based on an EPA comment that testing requirements and approved test methods are needed and because testing is needed under the adopted monitoring provisions, new §112.213(b) and (c) are added at adoption to provide the testing requirements and test methods to be used, respectively. Adopted §112.213(b)(1) requires that initial testing to be done by the compliance date if documentation of initial testing is not available and that the testing be done according to manufacturer's specifications. Adopted new §112.213(b)(2) requires that the incinerator be performance tested by the compliance date, that the performance test must be conducted with the incinerator operated as close as practicable to its maximum rated capacity, and that additional performance tests must be conducted at least every five years as a check on the accuracy of the monitoring. Adopted new §112.213(b)(3) requires that additional testing be conducted at the request of the executive director that complies with 40 CFR §60.104a. Adopted new §112.213(b)(4) requires that all performance tests must be conducted using test methods in adopted new §112.213(c).

Adopted new §112.213(c)(1) specifies that the testing under §112.213(b) must be conducted using the test methods in 40 CFR Part 60, Appendices A-1 through A-8 and Appendix B or other methods as specified, except as provided in §60.8(b). Adopted new §112.213(c)(2) specifies that SO_2 in exhaust gases from the incinerator must be determined using EPA Test Method 6 or 6C in 40 CFR, Part 60, Appendix A. Adopted new §112.213(c)(3) specifies that alternate test methods approved by the executive director and the EPA may be used.

§112.216, Recordkeeping Requirements

The commission adopts new §112.216 to specify the records required to be maintained. All records are required to be maintained for at least five years; based on an EPA comment, the format is specified at adoption as being either written or electronic. Adopted new §112.216 requires that the owner or operator maintain records of the continuous monitoring of sulfur content and flow rates of gases sent to the acid gas incinerator and flare and of which control device was in use. These records are sufficient to document compliance with the emission limits for each control device. At adoption, new provisions are added to §112.216 to require maintaining records of all monitoring data, emissions calculations, and testing on monitors for five years and maintaining documentation for five years of any exceedances of emission limits or standards and copies of all exceedance reports submitted to the appropriate regional office. The provision is added to be consistent with the requirements for other sites.

§112.217, Reporting Requirements

The commission adopts new §112.217(a) to specify the reporting to TCEQ Region 1 required from the owner or operator of the IACX Rock Creek Gas Plant if an affected emissions point exceeds an applicable emission limit or fails to meet a required stack parameter. The reports are due by March 31 of the year following the year in which the exceedance occurs. The reports are required to include at a minimum: the date of, and an explanation of, each exceedance and noncompliance with any required stack parameter; whether the exceedance or stack parameter noncompliance was concurrent with an authorized MSS activity for, or a malfunction of, the source or control device; the actions taken by the owner or operator to address the exceedance or stack parameter noncompliance and the cause(s); and a certification that the information provided is accurate. A report is required regardless of whether the exceedance occurred from planned or unplanned events or during startup or shutdown. If a reportable quantity (500 pounds or more) of SO_2 is released, the provisions of §101.211 also apply, as do the reporting requirements for emissions events in §101.201 if the criteria therein are met. The reporting deadline of March 31 is intended to provide enough time for sites to determine the root cause of each exceedance to include in the report required by this section.

Because a requirement for performance testing is added at adoption, a new §112.217(b) is added at adoption, and the subsequent subsection is re-lettered. The new §112.217(b) requires that copies of performance test reports be submitted to the appropriate TCEQ regional office and any local air pollutions control agency within 60 days after completing the test.

The commission adopts new §112.217(c), which was proposed as §112.217(b), as contingency measures if the EPA determines that the Hutchinson County SO_2 nonattainment area does not achieve attainment on or after the attainment date; based on a comment from the EPA, language is added at adoption throughout the subsection to include triggering the contingency measure if the EPA determines that the nonattainment area failed to meet RFP. If the EPA makes such a determination, the TCEQ will notify the owner or operator of each company (including successors, if appropriate) of the determination and that these contingency measures are triggered. The owner or operator of each company must conduct a full system audit of all their sources covered in this division and send a report of the results to the TCEQ executive director within 90 days of the notification from the TCEQ. The audit must include at a minimum a root cause analysis of the cause(s) of the failure to attain, including for the days that monitored exceedances occurred, a review of the hourly mass emissions from each SO_2 source, the wind speed and direction at the monitor with the NAAQS exceedance, and any emissions events that may have occurred. Based on comments that the basis for an EPA finding of failure to attain would affect the information that is useful in determining what contributed to the finding, wording is added at adoption to §112.217(b)(2) to clarify that review and consideration of meteorological data are only needed if the EPA's finding is based on ambient air monitor data or modeling data. To clarify what must be covered in an FSA in all cases from what must be covered only if the EPA's determination is based on ambient air monitor data or modeling data, the provisions are separated into §112.217(b)(2)(A) and (B), respectively. Additionally, based on comments, the term "exceptional event" is changed at adoption to "emissions event" for clarity. The provisions are included in the Reporting Requirements section of the rules because a report on the full system audit must be submitted to the executive director.

§112.218, Compliance Schedule

The commission adopts new §112.218 to specify the date by which each source identified in §112.210 is required to comply with the requirements of Division 2. Based on input from IACX, the date is changed at adoption to October 1, 2023, to allow time to ensure appropriate monitoring, recordkeeping and reporting procedures are in place. At adoption, the phrase "as soon as practicable, but" is removed from before the compliance date based on an EPA comment that the wording is not enforceable and other comment that the wording makes the actual compliance date uncertain.

DIVISION 3, REQUIREMENTS FOR THE ORION BORGER CARBON BLACK PLANT

§112.220, Applicability

The commission adopts new §112.220 to specify that the new rules apply to sources at the Orion Borger Carbon Black Plant at which the agency has determined emissions contribute to the potential exceedances of the 2010 SO_2 NAAQS based on modeling conducted for the concurrently adopted SIP revisions discussed elsewhere in this preamble. The adopted rule provisions in new Division 3 are site-specific and specified by the current name and the latitude/longitude. The latitude/longitude coordinates of the site are added at adoption because the provision proposed as §112.222(a), which would have required approval for changing the RN, is removed at adoption. The adopted rules are also EPN specific and specified by the current names of affected existing sources and their EPNs as documented in a specified version of the NSR permit or the name and EPN used in attainment demonstration modeling for sources to be authorized and constructed. The adopted requirements will continue to apply regardless of any changes of ownership, control, or documentation of the affected sources.

Instead of specifying the site by its RN, the location of the site in latitude/longitude coordinates is added at adoption because the provision proposed as §112.222(a), which would have required approval for changing the RN, is removed at adoption. This will eliminate the need for a SIP revision if the RN changes.

Based on comments, the last sentence of §112.220(a) is removed. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA, which was the intent of the proposed language. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

The TCEQ conducted attainment demonstration modeling for sources in the Hutchinson County nonattainment area using the emission rates (during normal operations and, when applicable, during authorized MSS activities) from the NSR permit for each site or lower emission rates if needed to demonstrate attainment as well as emission rates provided by the company for sources to be constructed. As discussed elsewhere in this preamble, the owners and operators of the five sites in the Hutchinson County SO_2 nonattainment area committed to lowering emission rates. The lower emission rates were the rates used in the attainment demonstration modeling, which also used stack parameters supplied for each emissions point. Modeling was conducted to determine which specific emissions points have emissions that contribute greater than the SIL of 3 ppb (i.e., 7.85 $\mu g/m^3$) to the modeled design value concentrations at any receptor in the Hutchinson County SO_2 nonattainment area. If the emissions point had a contribution to the modeled design value that was less than the SIL, it is not included in the rules. If the emissions point had a contribution to the modeled design value that was greater than the SIL, its emission rates are specified in the rules. When modeled collectively with all emissions sources in the nonattainment area, the emission rates specified in the rule resulted in modeled design values below the NAAQS.

§112.221, Definitions

The commission adopts new §112.221 to define five terms used in Division 3. The commission adopts new §112.221(1) to define block one-hour average. At adoption, a definition for continuous monitoring is added as new §112.221(2) based on an EPA comment. The subsequent definition is renumbered. Adopted new §112.221(3), which was proposed as §112.221(2), defines the Hutchinson County SO_2 nonattainment area; at adoption, the citation of the *Federal Register* publication is removed because it is not needed. The commission proposed the prior §112.221(3) to define pipeline quality natural gas, but this definition is not needed and is removed at adoption based on an EPA comment. Adopted new §112.221(4) defines production unit, which is used throughout the provisions for the two carbon black plants. Adopted new §112.111(5) defines tail gas, which is used throughout the provisions for the carbon black plant.

§112.222, Control Requirements

Proposed §112.222(a), which would have prohibited the owner or operator of the Orion Borger Carbon Black Plant from contravening the control requirements by changing the EPN designation of any emissions point without prior approval by the agency and the EPA, is removed at adoption based on public comment. The EPA stated that the only manner of approval for such a change would be a full SIP revision, which is overly burdensome. The subsequent subsections are re-lettered.

Adopted new §112.222(a), which was proposed as §112.222(b), provides SO_2 emission limits on a block one-hour average for the Waste Heat Boiler – CDS Stack (EPN E-6BN) at

144.11 lb/hr and the new Combined Flare (EPN CFL) at 750.05 lb/hr. Adopted new §112.222(b), which was proposed as §112.222(c), prohibits combusting tail gas in any source without an emission rate in subsection (a). The Orion Borger Carbon Black Plant's consent decree with the EPA limits flares to periods when the Waste Heat Boiler - CDS Stack is not in operation. Upon the compliance date of the adopted rules, the use of the Unit 1 Reactor/Flare (EPN E-10FL), Unit 2 Reactor/Flare (EPN-20FL), and Unit 4 Reactor/Flare (EPN E-40FL) are prohibited from operating by adopted new §112.222(c), which was proposed as §112.222(d). In addition, adopted new §112.222(d), which was proposed as §112.222(e), prohibits flaring after the compliance date in adopted new §112.228 if the new Combined Flare is not authorized and constructed. At adoption, proposed §112.222(f) is re-lettered as §112.222(e). Proposed §112.222(f)(1) would have required that the Combined Flare be used in place of the other three flares, but this provision is removed at adoption because it is redundant with the provisions in §112.222(b) and (c). The subsequent paragraphs are renumbered. Adopted new §112.222(e)(1), which was proposed as §112.222(f)(2), specifies that the Combined Flare is prohibited from operating when the Waste Heat Boiler – CDS Stack is operating. Adopted new §112.222(e)(2), which was proposed as §112.222(f)(3), specifies the stack height of 65.00 meters for the Combined Flare and the specific location where it must be located; based on an EPA comment that stack heights greater than 65 feet require approval, the wording "no less than" is removed at adoption from before the stack height.

Adopted new §112.222(f), which was proposed as §112.222(g) to allow the owner or operator to request an alternative SO_2 emission limit, is changed at adoption to reference AMOC provisions that were submitted in the comments from Phillips 66. The commission solicited comments on whether an additional mechanism to request alternative SO_2 emission limits, similar to the AMOC provisions 30 TAC Chapter 115, Subchapter J, Division 1, are appropriate to include in Subchapter F. Based on a comment received from the EPA that each revision to a state implementation plan requires a full SIP revision, proposed §112.222(g) is not adopted as proposed but is instead changed to a provision allowing the submittal of an application for an AMOC. The provisions for AMOCs are adopted as new §112.232(k). The specific AMOC rule text is adopted in Division 4.

§112.223, Monitoring Requirements

At adoption, the wording "the owner or operator shall" is added to §112.223(a) - (d), (f) and (h) to clarify that the requirements apply to the owner or operator. Adopted new §112.223 provides the monitoring requirements for sources at the Orion Borger Carbon Black Plant. The commission adopts new §112.223(a) to require the use of a CEMS for the Waste Heat Boiler – CDS Stack, as required under the Orion Borger Carbon Black Plant's consent decree with the EPA, which must be operated in accordance with specified federal requirements in 40 CFR Part 60. The requirement to comply with 40 CFR 60, Appendix B, Performance Specification 6 is explicitly stated at adoption to ensure that emissions are accurately determined. At adoption, the federal citations are incorporated into the subsection language instead of being separate paragraphs, and the term "sulfur dioxide" is added before the acronym "SO_2" for clarity.

Adopted new §112.223(b) requires the collection of data to be used to perform calculations to determine the amount of carbon black emitted from the flare when the flare is in operation. The mass balance need only be performed on days the flare is in use because the only other stack the sulfur could be emitted from is the Waste Heat Boiler – CDS Stack, which has a CEMS to monitor emissions. Adopted new §112.223(b)(1) requires monitoring of the sulfur content by weight of carbon black oil feedstock. At adoption, the frequency of the measurements is increased from daily to twice per day at least four hours apart.

Adopted new §112.223(b)(2) requires daily measurements of the sulfur content of each grade of carbon black produced by each carbon black production unit. A clause is added at adoption to allow the owner or operator to assume the produced carbon black contains no sulfur in lieu of testing. Because the amount of sulfur retained by carbon black is subtracted from the amount of sulfur in the carbon black oil to determine the amount of sulfur in the tail gas produced, assuming no sulfur in the carbon black is a conservative way of calculating SO_2 emissions and avoids the costs for testing. Adopted new §112.223(b)(3) requires hourly measurements of the amount of each grade of carbon black produced by each carbon black production unit.

Adopted new §112.223(c) requires the installation, calibration, and maintenance of a totalizing fuel flow meter for each carbon black furnace to continuously measure the feed rate of carbon black oil within an accuracy of 5%. The language was changed from second person to third person for consistency with the other sections. Adopted new §112.223(d) requires the installation, calibration, and maintenance of a totalizing tail gas flow meter for each carbon black combustion device to continuously measure the flow of tail gas within an accuracy of 5%. Adopted new §112.223(e) requires the use of an appropriate quality assurance and quality control process to validate continuous monitoring data for at least 95% of the time the monitored emissions point has emissions; use of an appropriate data substitution process, which is the most accurate method available, must be used to obtain all missing or invalidated monitoring data for the emissions point.

Adopted new §112.223(f) requires demonstrating compliance for the new Combined Flare (EPN CFL) by calculating actual hourly emissions via the mass balance equation in §112.223(h). At adoption, the calculation method is clarified by addition of an equation, and wording is added to specify that flared gases from all production units must be included. The new equation is added at adoption as Figure 30 TAC §112.223(f) and is a summation of the flared gas emissions from all production units with gases sent to the flare during an hour.

Adopted new §112.223(g) requires calculating emissions from the affected EPNs for each operational scenario as a block one-hour average. At adoption, the word “actual” is removed from the term “actual emissions” because these are calculated emissions, and the phrase “for each operational scenario occurring” is removed because the Orion

Borger Carbon Black Plant does not operate with different scenarios.

Adopted new §112.223(h) provides the equation for calculating SO_2 emissions from each production unit. A wording change is made at adoption to replace "emissions from each production unit" with "emissions generated by each production unit" for clarity that the calculation is for the actual emissions from each production unit rather than emissions arising from the tail gas generated by each production unit, a portion of which is burned in other combustion units. At adoption, the proposed equation in Figure 30 TAC §112.223(h) is replaced with an equation that includes factors for the density and temperature because those are needed for accurate calculations.

A new provision is added at adoption as §112.223(i) based on comments to allow the executive director of the agency to approve minor modifications of monitoring methods. As in the similar provision in 30 TAC §115.725(m), executive director approval and validation of the modified method using 40 CFR Part 63, Appendix A, Test Method 301, as applicable, is required for a modified monitoring method to be used. The language specifies that minor modifications include increases of the frequency of monitoring and replacements of parametric monitoring with a CEMS provided the quality control, quality assurance, and data validation requirements and accuracy specifications are specified and are at least as stringent as required in the rules.

§112.224, Testing Requirements

The commission adopts new §112.224 to specify the testing required for fuels, raw materials, produced carbon black and monitoring equipment used measure sulfur content of exhaust gas or the sulfur content at the inlet of the flares for sources at the Orion Borger Carbon Black Plant. Adopted new §112.224(a) requires that any performance testing be conducted with the source operating as near as practicable to its maximum rated capacity. Adopted new §112.224(b) requires that any performance test requested by the executive director be conducted using test methods in §112.225. Adopted new §112.224(c) specifies that when analysis of carbon black, carbon black oil, and fuels is required by this division, the test methods in adopted new §112.225 must be used.

§112.225, Approved Test Methods

The commission adopts new §112.225 to specify the test methods required to comply with the testing requirements in adopted new §112.224. Adopted new §112.225(a) requires that the EPA Test Methods in 40 CFR Part 60, Appendices A-1 through A-8 and Appendix B be used for performance testing required for the Orion Borger Carbon Black Plant unless an alternate test method is approved by the EPA under 40 CFR §60.8(b). The *Federal Register* citations in §112.225(a) and (c) are removed at adoption because they are not needed. Adopted new §112.225(b) specifies that testing of exhaust gases subject to Division 3 must be done using EPA Test Method 6 or 6C. Adopted new §112.225(c) specifies the test methods to be used for testing flare compliance.

Adopted new §112.225(d) specifies the test methods to be used for analyzing fuels and carbon black oil for sulfur content. At adoption, ASTM Method D1945-93, which is for natural gas, and ASTM Method D3588-93 are removed because they are not appropriate for determining the sulfur content of carbon black oil and replaced with ASTM Method D4294, which Orion uses. Adopted new §112.225(e) specifies the test method for carbon black. Adopted new §112.225(f) allows the use of alternate methods after approval by the executive director and the EPA.

§112.226, Recordkeeping Requirements

The commission adopts new §112.226 to specify the records required to be maintained by the Orion Borger Carbon Black Plant. All records are required to be maintained for at least five years. Because of an EPA comment that the format needs to be specified, a clause is added at adoption that the records must be in written or electronic format. Adopted new §112.226(1) requires records of the amounts (in units of lb/hr) of each grade of carbon black produced by each production unit. Adopted new §112.226(2) requires daily records of the sulfur content by weight of the carbon black oil feedstock. Adopted new §112.226(3) requires daily records of the sulfur content by weight of each grade of carbon black produced by each production unit. Adopted new §112.226(4) requires continuous records of carbon black oil flow rates to each production unit. Adopted new §112.226(5) requires continuous records of tail gas volumetric flow rates to each combustion device covered by adopted new §112.222. Adopted new §112.226(6) requires hourly records of the mass balance calculations for each source operating without a CEMS; at adoption, the term "sulfur dioxide" is moved to before the first use of the acronym SO_2 for clarity.

Adopted new §112.226(7) requires records of the continuous emissions monitoring data from the CEMS. At proposal, the provision was written to apply to each CEMS, but because there is only one, the word "each" is replaced with EPN E-6BN at adoption. Because of addition of a new §112.226(9), the word "and" is removed from the end of §112.226(7).

Adopted new §112.226(8) is changed at adoption to require documentation of any exceedances of emission limits or standards and copies of exceedance reports submitted to the appropriate regional office. New §112.226(9), which is added at adoption, requires copies of emissions test reports and associated records be maintained.

§112.227, Reporting Requirements

The commission adopts new §112.227(a) to specify the reporting to TCEQ Region 1 required from the Orion Borger Carbon Black Plant if an affected emissions point exceeds an applicable emission limit or fails to meet a required stack parameter. The reports are due by March 31 of the year following the year in which the exceedance occurs. The reports are required to include at a minimum: the date of, and an explanation of, each exceedance and noncompliance with any required stack parameter; whether the exceedance or stack parameter noncompliance was concurrent with an authorized MSS activity for, or a malfunction of, the source or control device;

the actions taken by the owner or operator to address the exceedance or stack parameter noncompliance and the cause(s); and a certification that the information provided is accurate. A report is required regardless of whether the exceedance occurred from planned or unplanned events or during startup or shutdown. If a reportable quantity (500 pounds or more) of SO_2 is released, the provisions of §101.211 also apply, as do the reporting requirements for emissions events in §101.201 if the criteria therein are met. The reporting deadline of March 31 is intended to provide enough time for sites to determine the root cause of each exceedance to include in the report required by this section.

Adopted new §112.227(b) requires the owner or operator of the Orion Borger Carbon Black Plant to submit within 60 days of testing the results of emissions testing for determining compliance with the emission standards of SO_2 to the TCEQ Office of Compliance and Enforcement, the appropriate TCEQ regional office, and any local air pollution control agency having jurisdiction.

The commission adopts new §112.227(c) as contingency measures if the EPA determines that the Hutchinson County SO_2 nonattainment area does not achieve attainment on or after the attainment date; based on a comment from the EPA, language is added at adoption throughout the subsection to include triggering the contingency measure if the EPA determines that the nonattainment area failed to meet RFP. If the EPA makes such a determination, the TCEQ will notify the owner or operator of each company (including successors, if appropriate) of the determination and that these contingency measures are triggered. The owner or operator of each company must conduct a full system audit of all their sources covered in this subchapter and send a report of the results to the TCEQ executive director within 90 days of the notification from the TCEQ. The audit must include at a minimum a root cause analysis of the cause(s) of the failure to attain, including for the days that monitored exceedances occurred, a review of the hourly mass emissions from each SO_2 source, the wind speed and direction at the monitor with the NAAQS exceedance, and any emissions events that may have occurred. Based on comments that the basis for an EPA finding of failure to attain would affect the information that is useful in determining what contributed to the finding, wording is added at adoption to §112.227(c)(2) to clarify that review and consideration of meteorological data are only needed if the EPA's finding is based on ambient air monitor data or modeling data. To clarify what must be covered in an FSA in all cases from what must be covered only if the EPA's determination is based on ambient air monitor data or modeling data, the provisions are separated into §112.227(c)(2)(A) and (B), respectively. Additionally, based on comments, the term "exceptional event" is changed at adoption to "emissions event" for clarity. The provisions are included in the Reporting Requirements section of the rules because a report on the full system audit must be submitted to the executive director.

§112.228, Compliance Schedule

The commission adopts new §112.228 to specify the date by which each source identified in §112.220 is required to comply with the requirements of Division 3.

January 1, 2025, was proposed for all sources. Based on an EPA comment that earlier compliance dates should be provided where possible, Orion was asked if they could comply earlier. Because the company indicated that they could meet most requirements by June 30, 2023, a new §112.228(a) is added at adoption specifying the compliance date of June 30, 2023, except for the provisions with which the company would need until January 1, 2025, to comply. The provisions needing additional time are 112.222(a)(2), (b) - (e), §112.223(b), (d), (f), (h), and §112.226(1) - (6). At adoption proposed §112.228 is lettered as §112.228(b) and requires the owner or operator to comply by January 1, 2025, with the provisions for which additional time after June 30, 2023, is needed. At adoption, the phrase “as soon as practicable, but” is removed from before “no later than January 1, 2025” based on an EPA comment that the wording is not enforceable and other comment that the wording makes the actual compliance date uncertain.

DIVISION 4, REQUIREMENTS FOR THE PHILLIPS 66 REFINERY

§112.230, Applicability

The commission adopts new §112.230 to specify that the new rules apply to sources at the Phillips 66 Refinery at which the agency has determined emissions contribute to potential exceedances of the 2010 SO_2 NAAQS based on modeling conducted for the concurrently adopted SIP revisions discussed elsewhere in this preamble. The adopted rule provisions in new Division 4 are site-specific and specified by the current name and the latitude/longitude coordinates of the site. The latitude/longitude coordinates of the site are added at adoption to §112.230(a) because the provision proposed as §112.232(a), which would have required approval for changing the RN, is removed at adoption. The adopted rules are also EPN specific and specified by the current names of affected existing sources and their EPNs as documented in a specified version of the NSR permit or the name and EPN used in attainment demonstration modeling for sources to be authorized and constructed. The adopted requirements will continue to apply regardless of any changes of ownership, control, or documentation of the affected sources.

Instead of specifying the site by its RN, the latitude and longitude coordinates for the site are added at adoption because the provision proposed as §112.232(a), which would have required approval for changing the RN, is removed at adoption. Additionally, the RNs are removed because it is consistent with the federal implementation plan that the EPA has proposed for Detroit, Michigan and because any change to an RN would require a full SIP revision, according to the EPA's comments.

Based on comments, the last sentence of §112.230(a) is removed. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA, which was the intent of the proposed language. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates into the rules into the SIP. After the EPA's approval, the rules are enforceable by both the EPA and the TCEQ. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

The TCEQ conducted attainment demonstration modeling for sources in the Hutchinson County nonattainment area using the emission rates (during normal operations and, when applicable, during authorized MSS activities) from the NSR permit for each site or lower emission rates if needed to demonstrate attainment as well as emission rates provided by the company for sources to be constructed. As discussed elsewhere in this preamble, the owners and operators of the five sites in the Hutchinson County SO_2 nonattainment area committed to lowering emission rates. The lower emission rates were the rates used in the attainment demonstration modeling, which also used stack parameters supplied for each emissions point. Modeling was conducted to determine which specific emissions points have emissions that contribute at a level greater than the SIL of 3 ppb (i.e., 7.85 $\mu g/m^3$) to the modeled design value concentrations at any receptor in the Hutchinson County SO_2 nonattainment area. If the emissions point had a contribution to the modeled design value that was less than the SIL, it is not included in the rules. If the emissions point had a contribution to the modeled design value that was greater than the SIL, its emission rates are specified in the rules. When modeled collectively with all emissions sources in the nonattainment area, the emission rates specified in the rule resulted in modeled design values below the NAAQS.

At adoption, EPN 66FL13 is removed from the list of sources included in EPN FLEX_R_CAP and EPN FLEX_MS_CAP in §112.230(b)(6) and (7), respectively, at the request of Phillips 66. NSR Permit 9868A for the site was revised to lower its emission limit such that its contribution to the modeled design value is less than the SIL, and §112.230(b)(6) and (7) are revised at adoption to reflect the date of the Maximum Allowable Emission Rate Table (MAERT) from this permit modification.

§112.231, Definitions

The commission adopts new §112.231 to define four terms used in Division 4. The commission adopts new §112.231(1) to define block one-hour average. At adoption, a definition for continuous monitoring is added as new §112.231(2) based on an EPA comment. The subsequent definitions are renumbered. Adopted new §112.231(3), which was proposed as §112.231(2), defines the Hutchinson County SO_2 nonattainment area; at adoption, the citation of the *Federal Register* publication is removed because it is not needed. Adopted new §112.231(4), which was proposed as §112.231(3), defines pipeline quality natural gas.

§112.232, Control Requirements

Proposed §112.232(a), which would have prohibited the owner or operator of the Phillips 66 Refinery from contravening the control requirements by changing the EPN designation of any emissions point without prior approval by the agency and the EPA, is removed at adoption based on public comment. The EPA stated that the only manner of approval for such a change would be a full SIP revision, which is overly burdensome. The subsequent subsections are re-lettered.

Adopted new §112.232(a), which was proposed as §112.232(b), limits EPN 34I1 (SRU Incinerator) emissions to 44.82 pounds lb/hr SO_2 during normal operations. Adopted new §112.232(b), which was proposed as §112.232(c), limits EPN 43I1 (SCOT Unit Incinerator) emissions to 37.00 lb/hr SO_2 during normal operations. Adopted new §112.232(c), which was proposed as §112.232(d), prohibits simultaneous operation of EPN 34I1 and EPN 43I1 during authorized MSS activities and limits the combined emissions from these units to 94.00 lb/hr during authorized MSS activities.

Adopted new §112.232(d), which was proposed as §112.232(e), was revised to clarify the flares' (EPN 66FL1, EPN 66FL2, EPN 66FL3, and EPN 66FL12) fuel and waste gas sulfur content limit of 162 ppmv does not apply to relief valves and gases generated during MSS activities in accordance with 40 CFR Part 60, Subpart Ja provisions. Instead, MSS emissions are limited by the pound per hour emission rates consistent with the attainment demonstration modeling. Although flare EPN 66FL13 was included in this provision at proposal, it is removed at adoption at the request of Phillips 66 because the P66 Borger Refinery is taking a federally enforceable limit that makes the flare an insignificant source.

Adopted new §112.232(e), which was proposed as §112.232(f), provides emissions caps for the four specified flares of 100.14 lb/hr during normal operations and 850.00 lb/hr during authorized MSS activities; these caps were represented in the attainment demonstration modeling as EPN FLARE_R_CAP and EPN FLARE_MS_CAP, respectively. Adopted new §112.232(f), which was proposed as §112.232(g), provides an emissions cap for the two SRU incinerators (EPN 34I1 and 43I1), and 44 EPNs for small sources (engines, heaters, and boilers) of 172.09 lb/hr during normal operations, which is lowered at adoption from 185.69 lb/hr in the proposal because of the removal of EPN 66FL13 from §112.230(6); this emissions cap was represented in the attainment demonstration modeling as EPN Flex_R_CAP.

Adopted new §112.232(g), which was proposed as §112.232(h), provides an emissions cap for the same 44 EPNs for small sources (but not the SRU incinerators) of 92.45 lb/hr during authorized MSS activities, which is lowered at adoption from 106.05 lb/hr in the proposal because of the removal of EPN 66FL13 from §112.230(7); this emissions cap was represented in the attainment demonstration modeling as EPN Flex_MS_CAP.

Proposed §112.232(i) is re-lettered at adoption as §112.232(h), and the emission limit for EPN 29P1 is changed to 97.37 lb/hr on a seven-day rolling average. All of the proposed emission limits and stack flow rates in proposed paragraphs (1) - (5) are removed at adoption because they are not needed with the adopted seven-day rolling average. The adopted emission limit was determined by multiplying the emission rate of 130.00 lb/hr used in the attainment demonstration modeling by a discount factor of 0.749. Phillips 66 provided CEMS data used to determine the discount factor for EPN 29P1. The attainment demonstration modeling shows that attainment is achieved with the modeled emission factor.

The 2014 SO_2 SIP guidance indicated that there may be cases in which an averaging time longer than one-hour may be appropriate provided that any emissions limits based on averaging periods longer than 1 hour are designed to have comparable stringency to a one-hour average limit at the CEV. The EPA indicated that if periods of hourly emissions above the CEV are a rare occurrence at a source, particularly if the magnitude of the emissions is not substantially higher than the CEV, these periods would be unlikely to have a significant impact on air quality. The EPA has further indicated that it does not expect that the use of longer-term averages will be necessary in cases where sources' emissions do not exhibit a high degree of variability. Therefore, the EPA recommends limiting the use of this approach to only those instances where a source's normal emissions variability would result in one-hour limits being extremely difficult to achieve in practice.

The 2014 SO_2 SIP guidance included a recommended approach to determine an appropriate longer-term averaging limit than a block one-hour emission rate. This approach involves calculating an appropriate longer-term averaging limit as a percentage of the one-hour CEV limit that would otherwise be applied to the source of SO_2 emissions. The first step of these calculations is to conduct air dispersion modeling to determine the CEV defined as the one-hour SO_2 emissions limit that shows attainment of the 2010 SO_2 NAAQS through modeling.

The discount factor is a percentage applied to the CEV that results in an emissions limit on a longer averaging time that can be expected to be comparably stringent as an emissions limit on a one-hour basis. This approach reconciles the inherent variability in hourly SO_2 emissions in the operations of some sources that may subsequently prove difficult to demonstrate compliance with an emissions limit on a one-hour basis. The EPA generally expects sources with longer averaging time limits to experience some occasions of hourly emissions to exceed the CEV while the majority of hourly emissions will remain below the CEV. This approach to establishing an emissions limit on a longer averaging time is expected to result in an emissions limit on the longer averaging time that remains protective of the 2010 SO_2 NAAQS because it is unlikely that the limited occurrences of hourly SO_2 emissions above the CEV would coincide with times when the meteorology is conducive for high ambient concentrations of SO_2.

Proposed §112.232(j) is re-lettered at adoption as §112.232(i), and the emission limit for EPN 40P1 is changed to 101.37 lb/hr on a seven-day rolling average. All of the proposed emission limits and stack flow rates in proposed paragraphs (1) - (5) are removed at adoption because they are not needed with the adopted seven-day rolling average. The adopted emission limit was determined by multiplying the emission rate of 130.00 lb/hr used in the attainment demonstration modeling by a discount factor of 0.780. Phillips 66 provided CEMS data used to determine the discount factor for EPN 40P1. The attainment demonstration modeling shows that attainment is achieved with the modeled emission factor.

Adopted new §112.232(j), which was proposed as §112.232(k), requires most emission limits in this section to be calculated on a block one-hour average basis. Because of the seven-day rolling average emission rates changed at adoption that were discussed previously, the clause “unless otherwise specified” is added at adoption to exclude the two seven-day rolling averages.

Adopted new §112.232(k), which was proposed as §112.232(l) to allow the owner or operator to request an alternative SO_2 emission limit, is changed at adoption. The commission solicited comments on whether an additional mechanism to request alternative SO_2 emission limits, similar to the AMOC provisions 30 TAC Chapter 115, Subchapter J, Division 1, are appropriate to include in Subchapter F. Based on a comment received from the EPA that the only approvable request for change is a full SIP revision, proposed §112.232(l) is not adopted as proposed but is instead changed to a provision allowing the submittal of an application for an AMOC. Some companies commented in favor of the flexibility that would be provided by the proposed rule provisions. In comments, Phillips 66 provided draft language for AMOC that is based on the provisions of 30 TAC Chapter 115 Subchapter J Division 1, which has previously been approved by the EPA as part of the SIP for ozone nonattainment areas.

As discussed in the last provision of the control requirements section in each of the other divisions in this subchapter, the commission has changed the alternative emission limit provision to one for an AMOC with a citation to §112.232(k). As re-lettered §112.232(k) is changed at adoption, the commission is providing provisions for an AMOC that are based on the Phillips 66 draft language but with some changes to be a rule subsection, to avoid constraining the options of the executive director, and to conform to *Texas Register* and Texas Legislative Drafting Council requirements.

Adopted new §112.232(k)(1) specifies that use of the AMOC provisions does not change the owner or operator's responsibility to comply with permit requirements for new construction or modification of sources.

Adopted new §112.232(k)(2) describes the criteria for applying for an AMOC plan. Subparagraph (A) provides that the owner or operator of a site subject to these adopted rules can apply, that the executive director must review submitted plans and may approve plans that meet the criteria and procedures of this section, and that if a plan does not meet the necessary criteria, the owner or operator can submit a request for a site-specific SIP revision instead. Subparagraph (B) provides that an applicant for a plan may request a waiver from the public notice requirements. Subparagraph (C) clarifies that applying for an AMOC does not relieve the owner or operator from complying with the rule requirements prior to a decision, and subparagraph (D) specifies that the provisions of an approved AMOC plan are enforceable.

Adopted new §112.232(k)(3) provides the criteria for approval of AMOC plans. All of the criteria must be met for a plan to be approved. Subparagraph (A) specifies that all sources covered by a plan must remain in the same account number, except that paragraph (8) allows for plans covering contiguous sites in some circumstances. Subparagraph (B) require that if the AMOC plan includes an increase in the pound per hour emission limit for a source subject to the control requirements in this subchapter, the AMOC plan must also include an equivalent decrease in the pound per hour emission limit for one or more sources. Subparagraph (C) describes the demonstration that must be included in an AMOC plan application: clause (i) defines the maximum allowed net increase in the off-property ground-level concentration of SO_2 on a highest, first-high basis at any receptor (i.e., the value for no receptor can increase) based on the lower of the critical ground-level value or the SIL; clause (ii) specifies that the demonstration must be based on modeling, databases, or the requirements of 40 CFR Part 51, Appendix W and the modeling conducted for the current SIP revisions. Subparagraph (D) specifies that the AMOC must be implemented and the reductions made after the attainment demonstration modeling done for the SIP revision that is concurrent with this rulemaking. Subparagraph (E) requires that the AMOC establish enforceable emission specifications and control requirements.

Adopted new §112.232(k)(4) provides the procedures for submitting an AMOC plan. Subparagraph (A) requires that the owner or operator submit an AMOC plan application and demonstration to the executive director with copies to the local TCEQ regional office, any air pollution control program with jurisdiction, and the EPA regional office. Subparagraph (B) specifies the information that must be included in a proposed AMOC plan: clause (i) specifies the applicant and site identification and contact person information; clause (ii) specifies the information to identify and describe the sources covered, the applicable rule provisions, and the normal operating conditions of the sources; clause (iii) specifies the emission specifications and limits and control requirements for each source that would be made enforceable by the AMOC plan; clause (iv) specifies a demonstration that the AMOC plan meets all requirements of paragraph (3); clause (v) specifies the information to be provided concerning the air pollution control program(s) with jurisdiction; clause (vi) specifies that any other relevant information requested by the executive director must be provided. Subparagraph (C) provides that the representations made for an AMOC plan become enforceable requirements upon approval of the plan by the executive director and the EPA, including emission limits, control requirements, monitoring, testing, reporting, and recordkeeping requirements. Subparagraph (D) specifies that applications for amending or revising AMOC plans must be submitted in accordance with the requirements of the chapter.

Adopted new §112.232(k)(5) provides the procedure for approving AMOC plans. Subparagraph (A) requires that notice sent by the executive director for a preliminary determination of approval must include a copy of the AMOC plan that was preliminarily approved. Subparagraph (B) requires that notice sent by the executive director for a determination to deny must include the reasons for the denial and specifies the determination is the final action of the executive director that is appealable to the Commission. Subparagraph (C) requires that upon receipt of the executive director's notice of preliminary approval, the applicant pay to publish notice, consistent with paragraph (5), of the applicant's intent to obtain an AMOC and the opportunity to provide written comment.

Subparagraph (D) requires that the executive director consider all significant and timely comments received and to prepare a written response. Subparagraph (E) provides that the executive director may in response to comments modify provisions of an AMOC plan, deny a plan, or approve a plan without change. Subparagraph (F) requires that the executive director send by a means documenting receipt a written notice of the final determination on an AMOC plan to the applicant, the EPA regional office, any air pollution control program with jurisdiction, and each commentor and that the notice include the final AMOC plan provisions, the response to comments, and announcement of the opportunity to appeal the decision to the Commission.

Subparagraph (G) provides that a recipient of the notice in subparagraph (F) may file an appeal of the decision within 15 days of receipt, that the appeal may be considered at the Commission's next regularly scheduled meeting that allows for adequate notice, and that the Commission may remand the determination to the executive director, deny the AMOC plan, or issue the AMOC plan unchanged. Subparagraph (H) specifies that within 45 days of final approval by the executive director (or the Commission for an appeal), the EPA may notify in writing the agency of their disapproval of the decision, including their reasons for disapproval and a specific listing of the changes to the AMOC plan needed for their approval, that the EPA can inform the agency prior to the 45-day deadline that they do not intend to disapprove, and that upon receipt of a timely EPA disapproval, the executive director must void or revise the AMOC plan and reissue notice under subparagraph (F). Subparagraph (I) specifies that if an appeal is not filed for an AMOC plan, it becomes effective upon the EPA's acceptance as provided in subparagraph (K). Subparagraph (J) specifies that if an appeal is not filed for an AMOC plan, it becomes effective upon the latter of the Commission's or the EPA's acceptance. Subparagraph (K) defines EPA acceptance as the explicit approval of a AMOC plan, notification by the EPA that they do not intend to disapprove, or failure of the EPA to meet the 45-day deadline for filing a disapproval.

Adopted new §112.232(k)(6) provides the format of public notice for an AMOC plan. Subparagraph (A) requires that notice be published in two successive issues of a general circulation newspaper closest to the site requesting the AMOC plan. Subparagraph (B) requires that the notice include the application number assigned by the executive director for the AMOC plan, the applicant's name, the type of source(s) and site covered in the AMOC, the location of the site, a brief description of the AMOC plan, the executive director's preliminary determination of approval, the location where copies of the proposed AMOC and related documentation and the executive director's preliminary analysis are available (including the TCEQ regional office, any local air pollution control program, and the EPA regional office), announcement of the opportunity to submit written comments and the procedure for doing so, the length of the public comment period (at least 30 days after the final notice publication), and the contact information for further information at the TCEQ regional office. Subparagraph (C) prohibits the executive director from taking final action until the applicant provides proof of adequate notice to the agency, the EPA, and any air pollution control program with jurisdiction.

Adopted new §112.232(k)(7) covers reviews of approved AMOC plans and termination of plans. Subparagraph (A) specifies that the term “compliance date” means when a source must comply with new or modified sections of Chapter 112. Subparagraph (B) specifies that an AMOC plan becomes void on the compliance date for a new or modified section affecting the source subject to the plan unless the plan is revised to reflect the new requirements. Subparagraph (C) specifies that the holder of an AMOC plan must comply with the rule requirements if the plan becomes void. Subparagraph (D) requires that upon final approval, the owner or operator keep a copy of the AMOC plan on site and available to representatives of the TCEQ, the EPA or an air pollution control program with jurisdiction. Subparagraph (E) requires that an AMOC plan holder submit a demonstration that the plan continues to meet all applicable rule requirements upon request from the executive director. Subparagraph (F) specifies that when a rule change is made that affects an AMOC plan, the holder is responsible for obtaining a new AMOC plan prior to the compliance date of the rule revision.

Adopted new §112.232(k)(8) provides that an AMOC plan may cover multiple sources on contiguous properties if separate applications for approval are submitted by each owner or operator.

§112.233, Monitoring Requirements

Adopted new §112.233 provides the monitoring requirements for sources at the P66 Borger Refinery, including but not limited to two FCCUs, two SRU Incinerators, and flares. At adoption, the wording “the owner or operator shall” is added to §112.233(a) -

(d) to clarify that the requirements apply to the owner or operator. Adopted new §112.233(a) and (b) require separate CEMS units for the FCCUs and SRU incinerators, respectively, that meet the federal requirements in 40 CFR Part 60, Subpart Ja for CEMS units. At adoption, several changes are made to the subsections. In addition to requiring all four CEMS to record SO_2 emissions at least every 15 minutes, the FCCU CEMS units are required to record the exhaust gas flow rates at least every 15 minutes to properly determine compliance with the emission rate levels in §112.232(h) and (i). Consistent with the emission rates, the flow rates are to be recorded at least every 15 minutes. Additionally at adoption, accuracy requirements are provided for the CEMS units (±2.5%), the flow measurement systems (±5%), and the temperature monitors (±1%). Because the requirements of 40 CFR §60.105a(g) are appropriate for the ensuring that the CEMS units are installed, calibrated, operated, and maintained properly to provide accurate monitoring, language is added to specify that the CEMS units must meet the requirements of 40 CFR §60.105a(g) despite the fact that the FCCUs and incinerators are not subject to that regulation.

Adopted new §112.233(c) requires determining each of four flares' inlet stream flow rate and total sulfur concentration according to 40 CFR §60.107a(e) monitoring procedures and specifications. Because flare EPN 66FL13 is removed from §112.230(6) at adoption such that the adopted rules do not apply to it, it is also removed from §112.233(c) at adoption. Similar to provisions for the CEMS units in §112.233(a) and (b), provisions are added at adoption as §112.233(c)(1) - (3) to provide accuracy requirements (same as in §112.233(a) and (b)) for the sulfur content, flow rate, and temperature monitors and to require exhaust flow and temperature monitors in new §112.233(c)(1) and (2), respectively. Additionally at adoption, §112.233(c)(3) is added to clarify requirements for two sulfur content monitoring options in subparagraphs (A) and (B). In adopted new §112.233(c)(3)(A), a monitoring option for total sulfur consistent with the requirements of 40 CFR §60.107a(e)(1) is added at adoption, along with the equation in Figure 30 TAC §112.233(c)(3)(A) to be used in calculating the sulfur content of flared gases. The equation is needed to properly calculate the content at standard conditions, as defined in 30 TAC §101.1. In new §112.233(c)(3)(B), a monitoring option for using H_2S as a surrogate for total sulfur consistent with the requirements of 40 CFR §60.107a(e)(2) is added at adoption, along with the equation in Figure 30 TAC §112.233(c)(3)(B) to be used in calculating the sulfur content of flared gases. The equation is needed to properly calculate the content at standard conditions.

New §112.233(d) was proposed to require continuous monitoring of the flow rate and sulfur content of fuels, waste gases, and other materials routed to each of the combustion units included in either or both of the emission rate caps in adopted new §112.230(6) and (7) and designated as Flex_R_CAP and Flex_MS_CAP in the attainment demonstration modeling. The provisions are changed at adoption to include the temperature of the fuel, to provide an option to monitor H_2S as a surrogate for total sulfur, and to exclude the flares that are subject to §112.233(c). Adopted new §112.233(d)(1) is added to specify that the volumetric flow to each source must be monitored with a totalizing gas flow meter with an accuracy of ±5% that is installed, calibrated, maintained, and operated according to the manufacturer's recommendations and specifications. Adopted new §112.233(d)(2) is added to specify that the temperature of the fuel must be monitored with temperature monitors with an accuracy of ±1% that are installed, calibrated, maintained, and operated according to the manufacturer's recommendations and specifications, with a provision that if the temperatures among the monitors does not vary by more than ±1%, the temperature can be monitored at a common location representative of each temperature monitor. Adopted new §112.233(d)(3) is added to specify that the sulfur content of the fuel can be monitored either for total sulfur or by monitoring H_2S as a surrogate for total sulfur. Adopted new §112.233(d)(3)(A) provides for the use of a total sulfur analyzer and includes the equation in Figure 30 TAC §112.233(d)(3)(A), which provides an equation for calculating hourly SO_2 emissions. Adopted new §112.233(d)(3)(B) provides for the using monitored H_2S as a surrogate for total sulfur content. To correlate the measured level of H_2S to total sulfur, a process is provided in §112.233(d)(3)(B). New §112.233(d)(3)(B)(i) requires collecting a fuel sample at least monthly, along with a provision that the sampling frequency can be reduced to quarterly if three consecutive monthly samples find that H_2S makes up at least 90% of the molar concentration of total sulfur but that the frequency reverts to monthly if any quarterly sample has an H_2S molar concentration less than 90% of the total sulfur molar concentration. New §112.233(d)(3)(B)(ii) requires having the fuel or SRU incinerator fuel and waste gas streams sampled for total sulfur and H_2S concentrations H_2S concentrations. New §112.233(d)(3)(B)(iii) requires calculating SO_2 emissions using the equation in Figure 30 TAC §112.233(d)(3)(B)(iii), which accounts for the H_2S and total sulfur concentrations in converting the measured H_2S concentrations to SO_2 emissions at standard conditions.

New §112.233(d)(3)(B)(iv) specifies that the total SO_2 emissions from EPN FLEX_R_CAP are calculated by summing the emissions calculated in §112.233(b)-(d) for each combustion unit in EPN FLEX_R_CAP. New §112.233(d)(3)(B)(v) specifies that the total SO_2 emissions from EPN FLEX_MS_CAP are calculated by summing the emissions calculated in §112.233(b) - (d) for each combustion unit in EPN FLEX_MS_CAP.

Adopted new §112.233(e) requires the use of an appropriate QA/QC process to validate continuous monitoring data for at least 95% of the time the monitored emissions point has emissions. Use of an appropriate data substitution process, which is the most accurate method available, must be used to obtain all missing or invalidated monitoring data for the emissions point.

A new provision is added at adoption as §112.233(f) based on comments to allow the executive director of the agency to approve minor modifications of monitoring methods. As in the similar provision in 30 TAC §115.725(m), executive director approval and validation of the modified method using 40 CFR Part 63, Appendix A, Test Method 301, as applicable, is required for a modified monitoring method to be used. The language specifies that minor modifications include increases of the frequency of monitoring and replacements of parametric monitoring with a CEMS provided the quality control, quality assurance, and data validation requirements and accuracy specifications are specified and are at least as stringent as required in the rules.

§112.234, Testing Requirements

Adopted new §112.234 provides the testing and related notification requirements for sources at the P66 Borger Refinery. Adopted new §112.234(a) specifies the relative accuracy tests for the CEMS units required for monitoring in adopted new §112.233 must be conducted using the federal provisions and schedules in 40 CFR §105a(g)(2) for CEMS on the FCCU and in 40 CFR §60.106a(1)(iii) for CEMS on the SRUs.

Adopted new §112.234(b) requires performing initial and subsequent testing of monitoring devices for combustion units and flares in accordance with the manufacturer's specifications so that the monitors are calibrated and function properly by the compliance date. At adoption, language is added stating the initial retesting of previously tested sources is only required if documentation is unavailable that the initial testing was conducted appropriately and in accordance with manufacturer's specifications.

Adopted new §112.234(c) requires that any additional performance testing requested by the executive director be conducted according to specified federal requirements in 40 CFR §60.104a and using the test methods in §112.235. The paragraph also specifies that the notification requirements in 40 CFR §60.8(d) apply to all performance tests except those conducted for continuous monitoring system maintenance or calibrations. Adopted new §112.234(d) specifies that when analysis of fuels is required by this division, the test methods in adopted new §112.235 must be used.

§112.235, Approved Test Methods

The commission adopts new §112.235 to specify the test methods required to comply with the testing requirements in adopted new §112.234. Adopted new §112.235(a) requires that the EPA Test Methods in 40 CFR Part 60, Appendices A-1 through A-8 and Appendix B be used for performance testing required for the P66 Borger Refinery. Adopted new §112.235(b) specifies that testing of exhaust gases at any site subject to Division 4 must be done using EPA Test Method 6 or 6C. Adopted new §112.235(c) specifies the test methods to be used for testing flare compliance at the P66 Borger Refinery.

Adopted new §112.235(d) specifies the test methods to be used for analyzing fuel gas for sulfur content; based on input from Phillips 66, the methods are changed at adoption to match those used at the site. At adoption, the test methods are expanded to include all methods used at the Phillips 66 Borger Refinery, and the date extensions on ASTM methods are removed based on an EPA comment that current methods should be used. ASTM Method D3588-93 is removed at adoption because it is not appropriate for determining sulfur content. Adopted new §112.235(e) allows the use of alternate methods after approval by the executive director and the EPA.

§112.236, Recordkeeping Requirements

The commission adopts new §112.236 to specify the records required to be maintained by the P66 Borger Refinery. All records are required to be maintained for at least five years. Based on an EPA comment that the format must be specified, a clause is added at adoption that the records must be in written or electronic format. Adopted new §112.236(1) requires all monitoring data and sampling analyses, including CEMS data for exhaust flow rates and sulfur composition data, used to quantify emissions be maintained. For the two FCCUs during authorized MSS activities, the specific emissions limit based on the flow rate (from §112.232(b)(5) and (6)) for each block one-hour period is also required to be recorded. Adopted new §112.236(2) requires maintaining the methods and calculations used for determining compliance. Adopted new §112.236(3) requires maintaining documentation of any exceedance and copies of the related reports submitted to the TCEQ; at adoption, wording is added to specify that the exceedance reports are those submitted to the appropriate regional office. Proposed §112.236(4) is changed at adoption to require maintaining copies of test reports and associated records in place of all emission test data and records. The test reports and associated records are sufficient to document compliance and are less burdensome for Phillips 66.

§112.237, Reporting Requirements

The commission adopts new §112.237(a) to specify the reporting to TCEQ Region 1 required from each site if an affected emissions point exceeds an applicable emission limit or fails to meet a required stack parameter. The reports are due by March 31 of the year following the year in which the exceedance occurs. The reports are required to include at a minimum: the date of, and an explanation of, each exceedance and noncompliance with any required stack parameter; whether the exceedance or stack parameter noncompliance was concurrent with an authorized MSS activity for, or a malfunction of, the source or control device; the actions taken by the owner or operator to address the exceedance or stack parameter noncompliance and the cause(s); and a certification that the information provided is accurate. A report is required regardless of whether the exceedance occurred from planned or unplanned events or during startup or shutdown. If a reportable quantity (500 pounds or more) of SO_2 is released, the provisions of §101.211 also apply, as do the reporting requirements for emissions events in §101.201 if the criteria therein are met. The reporting deadline of March 31 is intended to provide enough time for sites to determine the root cause of each exceedance to include in the report required by this section. Adopted new §112.237(b) requires the owners or operators of the P66 Borger Refinery to submit within 60 days of testing the results of emissions testing for determining compliance with the emission standards of SO_2 to the TCEQ Office of Compliance and Enforcement, the appropriate TCEQ regional office, and any local air pollution control agency having jurisdiction.

The commission adopts new §112.237(c) as contingency measures if the EPA determines that the Hutchinson County SO_2 nonattainment area does not achieve attainment on or after the attainment date; based on a comment from the EPA, language is added at adoption throughout the subsection to include triggering the contingency measure if the EPA determines that the nonattainment area failed to meet RFP. If the EPA makes such a determination, the TCEQ will notify the owner or operator of each company (including successors, if appropriate) of the determination and that these contingency measures are triggered. The owner or operator of each company must conduct a full system audit of all their sources covered in this subchapter and send a report of the results to the TCEQ executive director within 90 days of the notification from the TCEQ. The audit must include at a minimum a root cause analysis of the cause(s) of the failure to attain, including for the days that monitored exceedances occurred, a review of the hourly mass emissions from each SO_2 source, the wind speed and direction at the monitor with the NAAQS exceedance, and any emissions events that may have occurred. Based on comments that the basis for an EPA finding of failure to attain would affect the information that is useful in determining what contributed to the finding, wording is added at adoption to §112.237(c)(2) to clarify that review and consideration of meteorological data are only needed if the EPA's finding is based on ambient air monitor data or modeling data. To clarify what must be covered in an FSA in all cases from what must be covered only if the EPA's determination is based on ambient air monitor data or modeling data, the provisions are separated into §112.237(c)(2)(A) and (B), respectively. Additionally, based on comments, the term "exceptional event" is changed at adoption to "emissions event" for clarity. The provisions are included in the Reporting Requirements section of the rules because a report on the full system audit must be submitted to the executive director.

§112.238, Compliance Schedule

The commission adopts new §112.238 to specify the date by which each source identified in §112.230 is required to comply with the requirements of Division 4. At adoption, the phrase "as soon as practicable, but" is removed from before "no later than January 1, 2025" based on an EPA comment that the wording is not enforceable and other comment that the wording makes the actual compliance date uncertain.

DIVISION 5, REQUIREMENTS FOR THE TOKAI BORGER CARBON BLACK PLANT

§112.240, Applicability

The commission adopts new §112.240 to specify that the new rules apply to sources at the Tokai Borger Carbon Black Plant at which the agency has determined emissions contribute to potential exceedances of the 2010 SO_2 NAAQS based on modeling conducted for the concurrently adopted SIP revisions discussed elsewhere in this preamble. The adopted rule provisions in new Division 5 are site-specific and specified by the current name and street address. The address of the site is added at adoption and the RN removed because the provision proposed as §112.202(a), which would have required approval for changing the RN, is removed at adoption. The adopted rules are also EPN specific and specified by the current names of affected existing sources and their EPNs as documented in a specified version of the NSR permit or the name and EPN used in attainment demonstration modeling for sources to be authorized and constructed. The adopted requirements will continue to apply regardless of any changes of ownership, control, or documentation of the affected sources.

The TCEQ conducted attainment demonstration modeling for sources in the Hutchinson County nonattainment area using the emission rates (during normal operations and, when applicable, during authorized MSS activities) from the NSR permit for each site or lower emission rates if needed to demonstrate attainment as well as emission rates provided by the company for sources to be constructed. As discussed elsewhere in this preamble, the owners and operators of the five sites in the Hutchinson County SO_2 nonattainment area committed to lowering emission rates. The lower emission rates were the rates used in the attainment demonstration modeling, which also used stack parameters supplied for each emissions point. Modeling was conducted to determine which specific emissions points have emissions that contribute greater than the SIL of 3 ppb (i.e., 7.85 $\mu g/m^3$) to the modeled design value concentrations at any receptor in the Hutchinson County SO_2 nonattainment area. If the emissions point had a contribution to the modeled design value that was less than the SIL, it is not included in the rules. If the emissions point had a contribution to the modeled design value that was greater than the SIL, its emission rates are specified in the rules. When modeled collectively with all emissions sources in the nonattainment area, the emission rates specified in the rule resulted in modeled design values below the NAAQS.

Instead of specifying the site by its RN, the address of the site is added at adoption because the provision proposed as §112.242(a), which would have required approval for changing the RN, is removed at adoption. This will eliminate the need for a SIP revision if the RN changes.

Based on comments, the last sentence of §112.240(a) is removed. This change does not affect when the rules no longer apply because their removal from the SIP must be approved by the EPA, which was the intent of the proposed language. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. After the EPA's approval, the rules are enforceable by both the EPA and the TCEQ. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

Adopted §112,240(b) specifies the sources at the Phillips 66 Borger Refinery that are affected by Division 5. The sources are designated by the name and EPN used in the MAERT specified by date for the site's NSR Permit, except for the New Flare (EPN New Flare) that may be constructed but is not yet represented in the site's NSR permit.

§112.241, Definitions

The commission adopts new §112.241 to define five terms used in Division 5. The commission adopts new §112.241(1) to define block one-hour average. At adoption, a definition for continuous monitoring is added as new §112.241(2) based on an EPA comment. The subsequent definition is renumbered. Adopted new §112.241(3), which was proposed as §112.241(2), defines the Hutchinson County SO_2 nonattainment area; at adoption, the citation of the *Federal Register* publication is removed because it is not needed. The commission proposed the prior §112.241(3) to define pipeline quality natural gas, but this definition is not needed and is removed at adoption based on an EPA comment. Adopted new §112.241(4) defines production unit, which is used throughout the provisions for the two carbon black plants. Adopted new §112.241(5) defines tail gas, which is used throughout the provisions for the two carbon black plants.

§112.242, Control Requirements

Proposed §112.242(a), which would have prohibited an owner or operator of the Tokai Borger Carbon Black Plant from contravening the control requirements by changing the RN or EPN designation of any emissions point without prior approval by the agency and the EPA, is removed at adoption based on public comment. The EPA stated that the only manner of approval for such a change would be a full SIP revision, which is overly burdensome. The subsequent subsections are re-lettered.

Adopted new §112.242(a), which was proposed as §112.242(b), provides SO_2 emission limits during normal operations on a block one-hour average for the Boiler Stacks, Boiler 1 and 2 Common Stack (EPN 119) of 109.10 lb/hr when the boilers, singly or together, are operating; the Plant 1 Dryer Stack (EPN 121) of 441.40 lb/hr; and the Plant 2 Dryer Stack (EPN 122) of 595.60 lb/hr. If the new flare is not authorized and constructed, adopted new §112.242(b), which was proposed as §112.242(c), provides SO_2 emission limits on a block one-hour average when neither Boiler 1 nor 2 is operating: for the Plant 1, Unit 1 Primary Bag Filter Flare (EPN Flare-1) of 420.00 lb/hr; the Plant 1 Dryer Stack (EPN 121) of 250.00 lb/hr; the Plant 2 Dryer Stack (EPN 122) of 400.00 lb/hr; and specifies that there can be no SO_2 emissions from the Boiler Stacks, Boiler 1 and 2 Common Stack (EPN 119) during this period. At adoption, the wording in §112.242(b) and (c) "both Boilers 1 and 2 are not operating" is changed to "neither

Boiler 1 nor Boiler 2 is operating" for clarity; the proposed wording might have been misunderstood to mean that the emission limits apply if only one boiler is operating. If the new flare (EPN New Flare) is authorized, constructed, and operated, adopted new §112.242(c), which was proposed as §112.242(d), provides SO_2 emission limits on a block one-hour average when neither Boiler 1 nor 2 is operating for the new flare (EPN New Flare) of 806.60 lb/hr; the Plant 1 Dryer Stack (EPN 121) of 272.50 lb/hr; the Plant 2 Dryer Stack (EPN 122) of 436.00 lb/hr; and specifies that there can be no SO_2 emissions from the Boiler Stacks, Boiler 1 and 2 Common Stack (EPN 119) during this period. Adopted §112.242(d) prohibits combusting tail gas in any source whose emissions are not routed to EPN 121 (Plant 1 Dryer Stack), EPN 122 (Plant 2 Dryer Stack), EPN Flare-1 (Plant 1, Unit 1 Primary Bag Filter Flare), or EPN New Flare (New Flare).

Adopted new §112.242(e), prohibits tail gas from being combusted in a source whose emissions are not routed to EPN 119 (Boiler 1 and 2 Common Stack), EPN 121 (Plant 1 Dryer Stack), EPN 122 (Plant 2 Dryer Stack), EPN Flare-1 (Plant 1, Unit 1 Primary Bag Filter Flare), or EPN New Flare (New Flare 30 TAC §112.242(e), which was proposed as §112.242(f), is changed at adoption based on a comment to prohibit sending sulfur or sulfur containing compounds to these flares after the compliance date in adopted new §112.248, which only allows the use of current Flare 1 (EPN Flare-1) for controlling sulfur-containing materials but allows the use of these flares for controlling waste gases with no sulfur without the use of supplemental fuels with any sulfur-containing compounds. The prohibitions on the four flares are reorganized in §112.242(e) and

§112.242(f) for clarity

Adopted new §112.242(f), which was proposed as §112.242(g) to prohibit the use of all four flares for the carbon black reactors (EPNs Flare-1, Flare-2, Flare-3, and Flare-4) after the compliance date is changed at adoption based on a comment to prohibit sending any waste gases with sulfur to or using supplemental fuel with sulfur for EPN Flare 1 if the new flare EPN New Flare is constructed. The other three flares are removed from this subsection at adoption because the prohibition on their use for this purpose is already provided in adopted §112.242(e).

Adopted new §112.242(g) was proposed as §112.242(h) to prohibit the operation of the Plant 1 Number 1 and Number 2 Dryer Purge Stack (EPN 1) and Plant 1 Number 3 and Number 4 Dryer Purge stack (EPN 3) after the compliance date in adopted new §112.248. New §112.242(g) is changed at adoption based on a comment to only prohibit routing sulfur containing compounds to these sources so they can be operated with other supplemental fuels to combust fuels and waste gases with no sulfur. The company agreed to no longer emit SO_2 through Plant 1 Number 1 and Number 2 Dryer Purge Stack (EPN 1) and Plant 1 Number 3 and Number 4 Dryer Purge Stack (EPN 3) but may use these stacks for emissions from combustion of fuels without sulfur.

Adopted new §112.242(h), which was proposed as §112.242(i) to specify that if the new flare (EPN New Flare) is authorized and constructed, it must be used in place of the four existing flares (EPNs Flare-1, Flare-2, Flare-3, and Flare-4), is changed at adoption based on a comment to allow the use of the existing flares for waste gas and supplemental fuel streams without sulfur, under specified conditions. Proposed §112.242(h)(1), which proposed to require that EPN New Flare receive all waste gases instead of the other four flares, is removed at adoption, and the subsequent paragraphs are renumbered. Adopted new §112.242(h)(1), which was proposed as §112.242(h)(2), specifies that EPN New Flare may only receive tail gas when neither Boiler 1 nor 2 is operating. Adopted new §112.242(h)(2), which was proposed as §112.242(h)(3), was changed at adoption based on an EPA comment that changes to stack heights would require remodeling and now specifies that EPN New Flare is required to have a stack height of 60.35 meters and to be in the specific location where it was depicted in modeling.

Adopted new §112.242(i), which was proposed as §112.242(j), specifies that if the new flare (EPN New Flare) is not authorized, constructed, and operated, the Plant 1, Unit 1 Primary Bag Filter Flare (EPN Flare-1) may only receive tail gas when neither Boiler 1 nor 2 is operating.

Adopted new §112.242(j), which was proposed as §112.242(k) to allow the owner or operator to request an alternative SO_2 emission limit, is changed at adoption to reference AMOC provisions that were submitted in the comments from Phillips 66. The commission solicited comments on whether an additional mechanism to submit an application for alternative SO_2 emission limits, similar to the AMOC provisions 30 TAC

Chapter 115, Subchapter J, Division 1, are appropriate to include in Subchapter F. Based on a comment received from the EPA that the only approvable request for change is a full SIP revision, proposed §112.242(k) is not adopted as proposed but is instead changed to a provision allowing the submittal of an application for an AMOC. The provisions for AMOCs are adopted as new §112.232(k) and are cross-referenced in this subsection. The specific AMOC rule text is adopted in Division 4.

§112.243, Monitoring Requirements

At adoption, the wording "the owner or operator shall" is added to §112.243(a) - (d), (f) - (h), and (j) to clarify that the requirements apply to the owner or operator. Adopted new §112.243(a) requires the installation, maintenance, and calibration of a CEMS on Boiler Stacks, Boiler 1 and 2 Common Stack (EPN 119) and specifies the applicable federal requirements for the combined stack of the two boilers. At adoption, the citations of the federal requirements are included in the subsection language rather than as separate paragraphs for brevity. The requirement to comply with 40 CFR 60, Appendix B, Performance Specification 6 is explicitly stated at adoption to ensure that emissions are accurately determined. At adoption, the words "sulfur dioxide" are added before the acronym "SO_2" for clarity.

To determine emissions based on a mass balance for each production unit, adopted new §112.243(b)(1) and (2), respectively, require monitoring, which is increased at adoption from daily to twice daily four hours apart in §112.243(b)(1) based on an EPA comment. The monitoring must use the test methods in adopted new §112.245 of the sulfur content by weight of each grade of produced carbon black and twice daily monitoring using the test methods in adopted new §112.245 of the carbon black oil fed to each production unit. Adopted new §112.243(b)(3) requires hourly measurements of the amount of each grade of carbon black produced by each carbon black production unit.

Adopted new §112.243(c) requires installing, calibrating, maintaining, and operating totalizing fuel flow meters with an accuracy variation of no more than 5% to continuously monitor carbon black oil feed rate to each carbon black production unit. Adopted new §112.243(d) requires installing, calibrating, maintaining, and operating totalizing tail gas flow meters with an accuracy variation of no more than 5% to continuously monitor tail gas feed rate to each source combusting this fuel.

Adopted new §112.243(e) requires the use of an appropriate QA/QC process to validate continuous monitoring data for at least 95% of the time the monitored emissions point has emissions; use of an appropriate data substitution process, which is the most accurate method available, must be used to obtain all missing or invalidated monitoring data for the emissions point.

Changes are made at adoption to adopted new §112.243(f), which was proposed to require calculation, using a mass balance equation provided in proposed §112.243(j), of total SO_2 emissions from each production unit. Based on an EPA comment that calculation methods need to be more specific, the calculation methods for determining

SO_2 emissions from production units are adopted in separate subsections §112.243(f) - (h) and (j). Adopted §112.243(f) is changed from covering all production units to only covering the Plant 1 Dryer Stack (EPN 121), and the equation for determining its emissions is added as Figure 30 TAC §112.243(f), which is a summation of the SO_2 from the sulfur in tail gas from each production unit. New §112.243(g) was proposed to require calculating SO_2 emissions from each production unit but is changed at adoption to provide for determining emissions from the Plant 2 Dryer Stack (EPN 122) in the same manner as for the Plant 1 Dryer Stack (EPN 121). Proposed §112.243(h) is changed at adoption to provide an equation for determining emissions from EPN Flare 1 or EPN New Flare in the same manner as for the Plant 1 Dryer Stack (EPN 121) and Plant 2 Dryer Stack (EPN 122). All three new equations are summations of the emissions from each production unit routed to that EPN as calculated under §112.243(j).

Adopted new §112.243(i) requires demonstration of compliance on an hourly basis (calculated as a block one-hour average) for the emissions points specified in §112.242(a) - (c). At adoption, the term “actual emissions” is changed to “emissions” for clarity because these are calculated emissions. In addition, the term “operational scenario” is removed at adoption because it is not defined and is not necessary to identify all emission limits.

Based on a comment from EPA, §112.243(j) is changed at adoption to provide a more detailed equation for determining the emissions generated by each production unit. At adoption, the word “from” is changed to “generated by” for clarity.

A new provision is added at adoption as §112.243(k) to allow the use of a CEMS to directly monitor emissions in lieu of the material balance to monitoring emissions from the dryers.

A new provision is added at adoption as §112.243(l) based on comments. The new provision allows the executive director of the agency to approve minor modifications of monitoring methods. As in the similar provision in 30 TAC §115.725(m), executive director approval and validation of the modified method using 40 CFR Part 63, Appendix A, Test Method 301, as applicable, is required for a modified monitoring method to be used. The language specifies that minor modifications include increases of the frequency of monitoring and replacements of parametric monitoring with a CEMS provided the quality control, quality assurance, and data validation requirements and accuracy specifications are specified and are at least as stringent as required in the rules.

§112.244, Testing Requirements

At adoption, the wording “the owner or operator shall” is added to §112.244(a) - (d) to clarify that the requirements apply to the owner or operator The commission adopts new §112.244 to specify the testing required for fuels, raw materials, produced carbon black and monitoring equipment used measure sulfur content of exhaust gas or the sulfur content at the inlet of the flares. Adopted new §112.244(a) requires initial compliance demonstration testing by the compliance date for the emission points listed in §112.242(a) - (c) but excepts flares. The emission points for which initial compliance demonstration testing are: EPN 119 (Boiler Stacks, Boiler 1 and 2 Common Stack); EPN 121 (Plant 1 Dryer Stack); and EPN 122 (Plant 2 Dryer Stack) since it excepts flares from the requirement. The acronym SO_2 is removed at adoption because it is not used again in the section.

Adopted new §112.244(b) requires that the test methods in adopted new §112.245 be used for the initial demonstration of performance testing. Adopted new §112.244(c) requires that performance tests be conducted when operating the source as close to the maximum rated capacity as practicable.

Adopted new §112.244(d) requires that additional performance be conducted if requested by the executive director using the test methods in §112.245. At adoption, a provision is added to require that the owner or operator perform additional demonstrations of compliance at least every five years. Adopted new §112.244(d) specifies that when analysis of carbon black, carbon black oil, and fuels is required by this division, the test methods in adopted new §112.245(e) must be used.

§112.245, Approved Test Methods

The commission adopts new §112.245 to specify the test methods required to comply with the testing requirements in adopted new §112.244. Adopted new §112.245(a) requires that the EPA Test Methods in 40 CFR Part 60, Appendices A-1 through A-8 and

Appendix B be used for performance testing required for the Tokai Borger Carbon Black Plant unless an alternate test method is approved by the EPA. Adopted new §112.245(b) specifies that testing of exhaust gases must be done using EPA Test Method 6 or 6C. Adopted new §112.245(c) specifies the test methods to be used for testing flare compliance; although these federal requirements are specific to refineries, the rule requires the Tokai Borger Carbon Black Plant to follow those requirements because they are appropriate for ensuring that the monitoring provides accurate emission data. Adopted new §112.245(d) specifies the test methods to be used for analyzing fuels and carbon black oil for sulfur content in Division 5. At adoption, test Methods D3358-93 and D1945-91 are removed and replaced with Method D4294, which is a more appropriate test method for carbon black oil based a comment from EPA. Adopted new §112.245(e) specifies the test method for carbon black at both carbon black plants. Adopted new §112.245(f) allows the use of alternate methods after approval by the executive director and the EPA.

§112.246, Recordkeeping Requirements

The commission adopts new §112.246 to specify the records required to be maintained by the Tokai Borger Carbon Black Plant. All records are required to be maintained for at least five years. Based on an EPA comment that the format must be specified, a clause is added at adoption specifying that the records must be in written or electronic format. Adopted new §112.246(1) requires records (in units of lb/hr) of the amount of each grade of produced carbon black from each production unit. Adopted new §112.246(2) requires records of twice-daily sampling of the sulfur content of carbon black oil feed to each production unit. Adopted new §112.246(3) requires records of daily sampling of the sulfur content of each grade of produced carbon black from each production unit. Adopted new §112.246(4) requires continuous records of the flow rate of carbon black oil to each production unit. Adopted new §112.246(5) requires continuous records of the flow rate of tail gas from each production unit to each combustion device using this fuel. Adopted new §112.246(6) the mass balance calculations of emissions of SO_2; the words "sulfur dioxide" are added at adoption before the acronym "SO_2" for clarity. Adopted new §112.246(7) requires records of continuous emissions data from SO_2 CEMS units.

Adopted new §112.246(8), which was proposed to require maintaining copies of required emissions test data and records, is changed at adoption to require maintaining documentation of any exceedances of emission limits or standards and copies of any exceedance reports submitted to the regional office. A new §112.246(9) is added at adoption to require maintaining copies of any performance tests and associated records.

§112.247, Reporting Requirements

The commission adopts new §112.247(a) to specify the reporting to TCEQ Region 1 required by the owner or operator of the Tokai Borger Carbon Black Plant if an affected emissions point exceeds an applicable emission limit or fails to meet a required stack parameter. The reports are due by March 31 of the year following the year in which the exceedance occurs. The reports are required to include at a minimum: the date of, and an explanation of, each exceedance and noncompliance with any required stack parameter; whether the exceedance or stack parameter noncompliance was concurrent with an authorized MSS activity for, or a malfunction of, the source or control device; the actions taken by the owner or operator to address the exceedance or stack parameter noncompliance and the cause(s); and a certification that the information provided is accurate. A report is required regardless of whether the exceedance occurred from planned or unplanned events or during startup or shutdown. If a reportable quantity (500 pounds or more) of SO_2 is released, the provisions of §101.211 also apply, as do the reporting requirements for emissions events in §101.201 if the criteria therein are met. The reporting deadline of March 31 is intended to provide enough time for sites to determine the root cause of each exceedance to include in the report required by this section.

Adopted new §112.247(b) requires the owner or operator of the Tokai Borger Carbon Black Plant to submit within 60 days of testing the results of emissions testing for determining compliance with the emission standards of SO_2 to the TCEQ Office of Compliance and Enforcement, the appropriate TCEQ regional office, and any local air pollution control agency having jurisdiction.

The commission adopts new §112.247(c) as contingency measures if the EPA determines that the Hutchinson County SO_2 nonattainment area does not achieve attainment on or after the attainment date; based on a comment from the EPA, language is added at adoption throughout the subsection to include triggering the contingency measure if the EPA determines that the nonattainment area failed to meet RFP. If the EPA makes such a determination, the TCEQ will notify the owner or operator of each company (including successors, if appropriate) of the determination and that these contingency measures are triggered. The owner or operator of each company must conduct a full system audit of all their sources covered in this division and send a report of the results to the TCEQ executive director within 90 days of the notification from the TCEQ. The audit must include at a minimum a root cause analysis of the cause(s) of the failure to attain, including for the days that monitored exceedances occurred, a review of the hourly mass emissions from each SO_2 source, the wind speed and direction at the monitor with the NAAQS exceedance, and any emissions events that may have occurred. Based on comments that the basis for an EPA finding of failure to attain would affect the information that is useful in determining what contributed to the finding, wording is added at adoption to §112.247(c)(2) to clarify that review and consideration of meteorological data are only needed if EPA's finding is based on ambient air monitor data or modeling data. To clarify what must be covered in an FSA in all cases from what must be covered only if the EPA's determination is based on ambient air monitor data or modeling data, the provisions are separated into §112.247(c)(2)(A) and (B), respectively. Additionally, based on comments, the term "exceptional event" is changed at adoption to "emissions event" for clarity. The provisions are included in the Reporting Requirements section of the rules because a report on the full system audit must be submitted to the executive director.

§112.248, Compliance Schedule

The commission adopts new §112.248 to specify the date by which each source identified in §112.240 is required to comply with the requirements of this division. At adoption, the phrase "as soon as practicable, but" is removed from before "no later than January 1, 2025" based on an EPA comment that the wording is not enforceable and other comment that the wording makes the actual compliance date uncertain.

SUBCHAPTER G, REQUIREMENTS IN THE NAVARRO COUNTY NONATTAINMENT AREA

§112.300, Applicability

The commission adopts new §112.300 to establish applicability for the only source in Navarro County to which the new requirements apply, which is the lightweight aggregate kiln and its control system at the Streetman Plant. The NSR Permit 5337 MAERT dated May 29, 2020, designated the emissions point as EPN E3-1. Although the rule provisions are site-specific and specified by the current name and the address of the site and the affected source (including the EPN in a specified version of the NSR permit), the adopted rule specifies that the requirements will continue to apply regardless of any changes of ownership, control, or documentation of the affected source, unless removal of any requirement is approved by the EPA. The address of the site is added at adoption because the provision proposed as §112.302(a), which would have required approval for changing the RN, is removed at adoption.

Instead of specifying the site by its RN, the address of the site is added at adoption because the provision proposed as §112.302(a), which would have required approval for changing the RN, is removed at adoption. This will eliminate the need for a SIP revision if the RN changes.

The TCEQ conducted attainment demonstration modeling for the source in the Navarro County SO_2 nonattainment area using emission rates lower than authorized in the NSR permit that were provided by the company and are needed to demonstrate attainment. There is only one emissions point in the Navarro County SO_2 nonattainment area that contributed to nonattainment of the 2010 SO_2 NAAQS, so this was the only emissions point modeled. The company committed to reducing the emission rate sufficiently for air dispersion modeling to demonstrate attainment.

Based on comments, the last sentence of §112.300(a) is removed. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA, which was the intent of the proposed language. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

§112.301, Definitions

The commission adopts new §112.301 to define four terms used in Subchapter G. At adoption, a definition for continuous monitoring is added as new §112.301(1) based on an EPA comment. The subsequent definitions are renumbered. The commission adopts new §112.301(2), which was proposed as §112.301(1), to define lightweight aggregate kiln, which is the only type of source contributing to nonattainment in the Navarro County nonattainment area. For clarity, new §112.301(3), which was proposed as §112.301(2). is changed at adoption based on a comment from Arcosa to a definition based on industry standards instead of the one proposed that defined lightweight aggregate material based on a definition from the EPA. Adopted new §112.301(4), which was proposed as §112.301(3), defines the Navarro County SO_2 nonattainment area; at adoption, the citation of the *Federal Register* publication is removed because it is not needed. Based on comments from Arcosa and the EPA, proposed §112.301(4) is struck at adoption; because of the change in monitoring for the lightweight aggregate kiln, a definition for pipeline quality natural gas is not needed.

§112.302, Control Requirements

The commission adopts new §112.302 to specify the control requirements that are required for the lightweight aggregate kiln and any associated control device (EPN E3-1). The adopted rules include only the single emissions point from the kiln, which is currently from the stack of the water scrubber for controlling particulate emissions but may change if the company installs an additional control device for SO_2 or makes other changes. If additional emissions points are added to the lightweight aggregate kiln or its control system for any reason (such as a bypass), the same requirements apply to them. The adopted control requirements were determined for potential emissions points based on modeling conducted by the agency. The amount of SO_2 in the exhaust gases from the lightweight aggregate kiln must be controlled with a control device, by limiting the sulfur content of both the fuel combusted and raw materials processed, or by a combination of these methods. The limits apply when the lightweight aggregate kiln is operated or otherwise produces exhaust gases containing SO_2, such that the emission limits in this section are not exceeded during normal operations or during authorized MSS activities.

Proposed §112.302(a), which would have prohibited the owner or operator from contravening the control requirements by changing the EPN designation of the lightweight aggregate kiln's emission point (EPN E3-1) without prior approval by the agency and the EPA, is removed at adoption based on public comment. The EPA stated that the only manner of approval for such a change would be a full SIP revision, which is overly burdensome. The subsequent subsections are re-lettered.

Adopted new §112.302(a), which was proposed as §112.302(b), is changed at adoption based on a comment from the company to specify the minimum stack height for the kiln or any new control device, as well as the stack locations allowed. The company has not determined the type of control device to be used to meet the emission rate limitations in this section. Based on comments from Arcosa, the stack parameters are revised at adoption, including increasing the minimum stack height, and specifying the location of the stack within a certain area of the site. At adoption, a sentence is added for clarity that any bypass must vent through the stack. Based on an EPA comment, a typographical error is corrected at adoption by adding "aggregate" between the words "lightweight kiln" in the proposed subsection.

At adoption, the limits for SO_2 emissions, exhaust gas velocity, and temperature in §112.302(b), which was proposed as §112.302(c), are revised based on a comment from Arcosa. The adopted emission limit based on the attainment demonstration modeling that is sufficient to model attainment is 222.00 lb/hr SO_2. The stack parameters associated with this limit are the minimum exhaust gas temperature of 117 degrees Fahrenheit and the minimum stack velocity of 42.5 feet per second. Proposed §112.302(d) is struck at adoption based on Arcosa’s comment because an alternate emission limit is not needed. The attainment demonstration modeling showed that the revised emission limit and associated stack parameters are sufficient to model attainment. Based on Arcosa’s commitment in its comments to install a CEMS, proposed §112.302(e) and (f) are struck at adoption. Monitoring of fuels is not needed with a CEMS, which Arcosa committed to installing in its comments.

Proposed §112.302(g) would have allowed the owner or operator to request alternate SO_2 emission limits. The subsection is removed at adoption based on an EPA comment that these changes are not approvable unless submitted as full SIP revisions. The provision is not needed in the rules for such action to be allowed. Instead, adopted §112.302(c), which was proposed as §112.302(g), is changed at adoption to include AMOC provisions based off language submitted in the comments from Phillips 66. The commission solicited comments on whether an additional mechanism to request alternative SO_2 emission limits, similar to the AMOC provisions 30 TAC Chapter 115, Subchapter J, Division 1, are appropriate to include in the adopted rules. Although there were no comment supporting an AMOC for Subchapter G, it is included at adoption for consistency with Subchapters E and F of this chapter.

§112.303, Monitoring Requirements

Adopted new §112.303 provides the monitoring requirements for the lightweight aggregate kiln and future control at the Streetman Plant. Based on EPA and Arcosa comments, the introductory paragraph is changed at adoption to require a CEMS to directly monitor SO_2 emissions from the stack. New §112.303 was proposed to require monitoring of the amounts and sulfur contents of fuels and raw materials to allow calculation of SO_2 emissions. Because Arcosa committed to installing a CEMS, the provisions are changed at adoption to require monitoring with the CEMS that is installed, operated, calibrated, and maintained according to the manufacturer's specifications and used in accordance with 40 CFR §60.13 and 40 CFR Part 60, Appendix B, Performance Specification 2 and 6 and Appendix W. New t§112.303(1) was proposed to require monitoring the amount of raw materials processed each hour; because this monitoring is not needed with a CEMS, the provision is changed at adoption to require that the CEMS monitor SO_2 emissions from the stack. New §112.303(2) was proposed to require monitoring the amount of each type of fuel used each hour; because this monitoring is not needed with a CEMS, the provision is removed at adoption. New §112.303(3) was proposed to require monthly analysis of the sulfur content of natural gas; because this monitoring is not needed with a CEMS, the provision is removed at adoption.

Proposed §112.303(4) required weekly monitoring of the average sulfur content of coal and coke fuels; because this monitoring is not needed with a CEMS, the provision is removed at adoption. Proposed §112.303(5), which would have required the monitoring of average sulfur content of raw materials but is not needed with a CEMs, is removed at adoption. The subsequent paragraphs are renumbered.

Adopted §112.303(2), which was proposed as §112.303(6), requires that the CEMS monitor the temperature and velocity of exhaust gases. The option of monitoring at the outlet of the control device is removed at adoption because all emissions must be through the stack, which must be monitored with the CEMS. Adopted §112.303(3), which was proposed as §112.303(7) to require quality control of monitoring data, requires the use of an appropriate QA/QC process to validate continuous monitoring data for at least 95% of the time the monitored emissions point has emissions and use of an appropriate data substitution process, which is the most accurate method available, to obtain all missing or invalidated monitoring data for the emissions point.

A new provision is added at adoption as §112.303(4) based on comments to allow the executive director of the agency to approve minor modifications of monitoring methods. As in the similar provision in 30 TAC §115.725(m), executive director approval and validation of the modified method using 40 CFR Part 63, Appendix A, Test Method 301, as applicable, is required for a modified monitoring method to be used. The language specifies that minor modifications include increases of the frequency of monitoring and replacements of parametric monitoring with a CEMS provided the quality control, quality assurance, and data validation requirements and accuracy specifications are specified and are at least as stringent as required in the rules.

§112.304, Testing Requirements

The commission changes new §112.304 at adoption to specify the testing required for a CEMS, rather than for fuels, raw materials, and the exhaust vent, to comply with the monitoring requirements in adopted new §112.303. Because calibration of a CEMS requires performance testing after its installation but before it is certified as accurate, new §112.304(a) is changed at adoption to require the owner or operator to performance test within 60 days of installation of the CEMS, which allows at least 30 days for calibration of the CEMS to be completed before the compliance date. Proposed §112.304(b) - (f) are struck at adoption because the testing that was proposed is not needed when a CEMS is used. Proposed new §112.304(g) is re-lettered as §112.304(b) at adoption and requires conducting additional performance testing if requested by the executive director using test methods specified in §112.305.

§112.305, Approved Test Methods

The commission adopts new §112.305 to specify the test methods that are required to comply with the testing requirements in adopted new §112.304. The test methods relate to the testing requirements in adopted new §112.304 and are specified by type of testing; changes are made at adoption to cover the requirements for the testing needed for a CEMS. Adopted new §112.305(a) requires EPA Test Method 6 or 6C for testing SO_2 in exhaust gases; language is added at adoption to specify that the requirement applies during the initial performance test and relative accuracy test audits. Adopted new §112.305(b) specifies the other test methods to be used in performance tests and relative accuracy test audits. Proposed §112.305(c) and (d) are removed at adoption because testing of fuels and raw materials are not needed with a CEMS. Proposed new §112.305(e) is re-lettered as §112.305(c) at adoption and allows the use of alternate testing methods after prior approval by the executive director and the EPA.

§112.306, Recordkeeping Requirements

The commission adopts new §112.306 with changes at adoption to specify the records required to be maintained for at least five years related to monitoring with a CEMS instead of the proposed provisions for monitoring fuels and raw materials. Based on an EPA comment that the format of records must be specified, a clause is added at adoption to specify that the records must be in written or electronic format. Proposed §112.306(1) - (4), (6) and (7) are removed because this monitoring is not needed with a CEMS, so no records are required. Proposed §112.306(5) is renumbered as §112.306(1) at adoption and requires records of the continuous monitoring of exhaust gas temperature and velocity, with the sulfur content of the exhaust gas added at adoption to reflect the data generated by the CEMS to be installed.

Proposed new §112.306(8) is renumbered as §112.306(2) at adoption and requires records of exceedances of emission limits or standards and copies of all exceedance reports submitted to the appropriate regional office. The provision is added to be consistent with the requirements for other sites. Proposed new §112.306(9) is renumbered as §112.306(3) at adoption; the owner or operator is required to maintain a copy of each performance test report and relative accuracy test audit report and associated records.

§112.307, Reporting Requirements

The commission adopts new §112.307(a) to specify the reporting required from the site if an affected emissions point exceeds the applicable SO_2 emission limit for the stack parameters at any given time or if required stack parameters are not met. The reports are due by March 31 of the year following the year in which the exceedance occurs. The reports are required to include at a minimum: the date of, and an explanation of, each exceedance and noncompliance with any required stack parameter; whether the exceedance or stack parameter noncompliance was concurrent with an authorized MSS activity for, or a malfunction of, the source or control device; the actions taken by the owner or operator to address the exceedance or stack parameter noncompliance and the cause(s); and a certification that the information provided is accurate. A report is required regardless of whether the exceedance occurred from planned or unplanned events or during startup or shutdown. If a reportable quantity (500 pounds or more) of SO_2 is released, the provisions of §101.211 also apply, as do the reporting requirements for emissions events in §101.201 if the criteria therein are met. The reporting deadline of March 31 is intended to provide enough time for sites to determine the root cause of each exceedance to include in the report required by this section.

The commission adopts new §112.307(b) to require the owner or operator to submit within 60 days of testing the results of emissions testing for determining compliance with the emission standards of SO_2 to the appropriate TCEQ regional office. The commission adopts new §112.307(c) as contingency measures if the EPA determines that the Navarro County SO_2 nonattainment area does not achieve attainment on or after the attainment date; based on a comment from the EPA, language is added at adoption to throughout the subsection include triggering the contingency measure if the EPA determines that the nonattainment area failed to meet RFP. If the EPA makes such a determination, the TCEQ will notify the owner or operator of the Streetman Plant (including successors, if appropriate) of the determination and that these contingency measures are triggered. The owner or operator must conduct a full system audit of the lightweight aggregate kiln and its emissions controls and send a report of the results to the TCEQ executive director within 90 days of the notification from the TCEQ. The audit must include at a minimum a root cause analysis of the cause(s) of the failure to attain, including for the days that monitored exceedances occurred, a review of the hourly mass emissions from the lightweight aggregate kiln and its emissions controls, the wind speed and direction at the monitor with the NAAQS exceedance, and any emissions events that may have occurred. Based on comments that the basis for an EPA finding of failure to attain would affect the information that is useful in determining what contributed to the finding, wording is added at adoption to §112.307(c)(2) to clarify that review and consideration of meteorological data are only needed if the EPA's finding is based on ambient air monitor data or modeling data. To clarify what must be covered in an FSA in all cases from what must be covered only if the EPA's determination is based on ambient air monitor data or modeling data, the provisions are separated into §112.307(c)(2)(A) and (B), respectively. Additionally, based on comments, the term "exceptional event" is changed at adoption to "emissions event" for clarity. The provisions are included in the Reporting Requirements section of the rules because a report on the full system audit must be submitted to the executive director.

§112.308, Compliance Schedule

The commission adopts new §112.308 to specify the date by which the source identified in §112.300 is required to comply with the requirements of Subchapter G. At adoption, the phrase "as soon as practicable, but" is removed from before "no later than January 1, 2025" based on an EPA comment that the wording is not enforceable and other comment that the wording makes the actual compliance date uncertain.

Final Regulatory Impact Determination

The commission reviewed the adopted rulemaking in light of the regulatory impact analysis requirements of Texas Government Code, §2001.0225, and determined that the adopted rulemaking does not meet the definition of a "Major environmental rule" as defined in that statute. A "Major environmental rule" means a rule, the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. Additionally, the adopted rulemaking does not meet any of the four applicability criteria for requiring a regulatory impact analysis for a major environmental rule, which are listed in Texas Government Code, §2001.0225(a). Texas Government Code, §2001.0225, applies only to a major environmental rule, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

The adopted rulemaking's purpose is to create state and federally enforceable emission limits and stack parameters as well as accompanying compliance obligations (monitoring, recordkeeping, reporting, and testing).

The adopted rulemaking would create new rule sections. The revisions to Chapter 112 would be used as control strategies for demonstrating attainment of the 2010 SO_2 NAAQS in the areas designated nonattainment, as discussed elsewhere in this preamble.

The adopted rulemaking implements requirements of the FCAA, 42 United States Code

(USC), §7410, which requires states to adopt a SIP that provides for the implementation, maintenance, and enforcement of the NAAQS in each air quality control region of the state. While 42 USC, §7410 generally does not require specific programs, methods, or reductions in order to meet the standard, the SIP must include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance as may be necessary or appropriate to meet the applicable requirements of this chapter (42 USC, Chapter 85). The provisions of the FCAA recognize that states are in the best position to determine what programs and controls are necessary or appropriate in order to meet the NAAQS. This flexibility allows states, affected industry, and the public to collaborate on the best methods for attaining the NAAQS for the specific regions in the state. Even though the FCAA allows states to develop their own programs, this flexibility does not relieve a state from developing a program that meets the requirements of 42 USC, §7410. States are not free to ignore the requirements of 42 USC, §7410 and must develop programs to assure that their contributions to nonattainment areas are reduced so that these areas can be brought into attainment on the schedule prescribed by the FCAA.

The requirement to provide a fiscal analysis of adopted regulations in the Texas Government Code was amended by Senate Bill (SB) 633 during the 75th Legislature, 1997. The intent of SB 633 was to require agencies to conduct a regulatory impact analysis of extraordinary rules. These rules are identified in the statutory language as major environmental rules that will have a material adverse impact and will exceed a requirement of state law, federal law, or a delegated federal program, or are adopted solely under the general powers of the agency. With the understanding that this requirement would seldom apply, the commission provided a cost estimate for SB 633 concluding that "based on an assessment of rules adopted by the agency in the past, it is not anticipated that the bill will have significant fiscal implications for the agency due to its limited application." The commission also noted that the number of rules that would require assessment under the provisions of the bill was not large. This conclusion was based, in part, on the criteria set forth in the bill that exempted adopted rules from the full analysis unless the rule was a major environmental rule that exceeds a federal law.

As discussed earlier in this preamble, the FCAA does not always require specific programs, methods, or reductions in order to meet the NAAQS; thus, states must develop programs for each area contributing to nonattainment to help ensure that those areas will meet the required attainment deadlines. Because of the ongoing need to address nonattainment issues and to meet the requirements of the FCAA, 42 USC, §7410 the commission routinely proposes and adopts SIP rules. The legislature is presumed to understand this federal scheme. If each rule adopted for inclusion in the SIP was considered to be a major environmental rule that exceeds federal law, then every SIP rule would require the full regulatory impact analysis contemplated by SB 633. This conclusion is inconsistent with the conclusions reached by the commission in its cost estimate and by the Legislative Budget Board (LBB) in its fiscal notes. Since the legislature is presumed to understand the fiscal impacts of the bills it passes and that presumption is based on information provided by state agencies and the LBB, the commission believes that the intent of SB 633 was only to require the full regulatory impact analysis for rules that are extraordinary in nature. While the SIP rules will have a broad impact, the impact is no greater than is necessary or appropriate to meet the requirements of the FCAA. For these reasons, rules adopted for inclusion in the SIP fall under the exception in Texas Government Code, §2001.0225(a) because they are required by federal law.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially un-amended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Berry v. State Farm Mut. Auto Ins. Co.*, 9 S.W.3d 884, 893 (Tex. App. Austin 2000); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App. Austin 2000, *pet. denied*); *Texas Citrus Exchange v. Sharp*, 955 S.W.2d 164 (Tex. App. Austin 1997); *Texas Dept. of Protective and Regulatory Services v. Mega Child Care, Inc.*, 145 S.W.3d 170 (Tex. 2004); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the regulatory impact analysis requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." The legislature specifically identified Texas Government Code, §2001.0225, as falling under this standard. The commission has substantially complied with the requirements of Texas Government Code, §2001.0225.

As explained previously in this preamble, the specific intent of the adopted rulemaking is to create state and federally enforceable emission limits and stack parameter requirements as well as accompanying compliance obligations (monitoring, recordkeeping, reporting, and testing) that would be used as control strategies for demonstrating attainment of the 2010 SO_2 NAAQS in the areas designated nonattainment. Thus, the adopted rulemaking does not exceed a standard set by federal law or exceed an express requirement of state law. No contract or delegation agreement covers the topic that is the subject of this adopted rulemaking. Therefore, this adopted rulemaking is not subject to the regulatory analysis provisions of Texas Government Code, §2001.0225(b) because it does not meet the definition of a "major environmental rule," and also does not meet any of the four applicability criteria for a major environmental rule.

The commission invited public comment regarding the draft regulatory impact analysis determination during the public comment period and received comments on the proposed analysis. The response to comments section of this preamble includes responses to these comments.

Takings Impact Assessment

The commission evaluated the adopted rulemaking and performed an assessment of whether Texas Government Code, Chapter 2007 is applicable. The specific purpose of the adopted rulemaking is to create state and federally enforceable emission limits and stack parameter requirements as well as accompanying compliance obligations (monitoring, recordkeeping, reporting, and testing) that will be used as control strategies for demonstrating attainment of the 2010 SO_2 NAAQS in the areas designated nonattainment.

Texas Government Code, §2007.003(b)(4), provides that Texas Government Code, Chapter 2007 does not apply to this adopted rulemaking because it is an action reasonably taken to fulfill an obligation mandated by federal law.

The adopted rulemaking implements requirements of the FCAA, 42 United States Code (USC), §7410, which requires states to adopt a SIP that provides for the implementation, maintenance, and enforcement of the NAAQS in each air quality control region of the state. While 42 USC, §7410 generally does not require specific programs, methods, or reductions in order to meet the standard, the SIP must include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance as may be necessary or appropriate to meet the applicable requirements of this chapter (42 USC, Chapter 85). The provisions of the FCAA recognize that states are in the best position to determine what programs and controls are necessary or appropriate in order to meet the NAAQS. This flexibility allows states, affected industry, and the public to collaborate on the best methods for attaining the NAAQS for the specific regions in the state. Even though the FCAA allows states to develop their own programs, this flexibility does not relieve a state from developing a program that meets the requirements of 42 USC, §7410. States are not free to ignore the requirements of 42 USC, §7410 and must develop programs to assure that their contributions to nonattainment areas are reduced so that these areas can be brought into attainment on the schedule prescribed by the FCAA. While the SIP rules will have an impact on the emissions points subject to the emission limits and compliance obligations required by the adopted rules, the impact is no greater than is necessary or appropriate to meet the requirements of the FCAA.

In addition, the commission's assessment indicates that Texas Government Code, Chapter 2007 does not apply to these adopted rules because this action is taken in response to a real and substantial threat to public health and safety; that is designed to significantly advance the health and safety purpose; and that it does not impose a greater burden than is necessary to achieve the health and safety purpose. Thus, this action is exempt under Texas Government Code, §2007.003(b)(13). The adopted rules fulfill the FCAA requirement for states to create plans including control strategies to attain and maintain the NAAQS, as discussed elsewhere in this preamble. The adopted rules will assist in achieving the timely attainment of the 2010 SO_2 NAAQS and reduced public exposure to SO_2 emissions. The NAAQS are promulgated by the EPA in accord with the FCAA, which requires the EPA to identify and list air pollutants that “cause[s] or contribute[s] to air pollution which may reasonably be anticipated to endanger public health and welfare” and “the presence of which in the ambient air results from numerous or diversion mobile or stationary sources”, as required by 42 USC §7408. For those air pollutants listed, the EPA then is required to issue air quality criteria identifying the latest scientific knowledge regarding on adverse health and welfare effects associated with the listed air pollutant, in accord with 42 USC §7408. For each air pollutant for which air quality criteria have been issued, the EPA must publish adopted primary and secondary air quality standards based on the criteria that specify a level of air quality requisite to protect the public health and welfare from any known or anticipated adverse effects associated with the presence of the air pollutant in the ambient air, as required by 42 USC §7409. As discussed elsewhere in this preamble, states have the primary responsibility to adopt plans designed to attain and maintain the NAAQS.

Consequently, the adopted rulemaking meets the exemption criteria in Texas Government Code, §2007.003(b)(4) and (13). For these reasons, Texas Government Code, Chapter 2007 does not apply to this adopted rulemaking.

Consistency with the Coastal Management Program

The commission reviewed this rulemaking for consistency with the Coastal Management Program (CMP) goals and policies in accordance with the regulations of the Coastal Coordination Advisory Committee and determined that the rulemaking will not affect any coastal natural resource areas because the rules only affect counties outside the CMP area and is, therefore, consistent with CMP goals and policies.

The commission invited public comment regarding the consistency with the coastal management program during the public comment period. No comments were received regarding the coastal management program.

Effect on Sites Subject to the Federal Operating Permits Program

Chapter 112 is an applicable requirement under 30 TAC Chapter 122, Federal Operating Permits Program. Owners or operators of affected sites subject to the federal operating permit program must, consistent with the revision process in Chapter 122, upon the compliance date of the rules, revise their operating permit to include the new Chapter 112 requirements.

Public Comment

The commission offered public hearings in Big Spring, Texas, on May 18, 2022, and in Corsicana, Texas, on May 23, 2022, but no one provided comments at either hearing. The commission held a public hearing on May 19, 2022, in Borger, Texas. The comment period closed on June 2, 2022. The commission received comments from Arcosa

Incorporated (Arcosa); Chevron Phillips Chemical Company LP (CP Chem); Alon USA, LP, a wholly owned subsidiary of Delek US Holdings (Alon); the United States Environmental Protection Agency, Region 6 (EPA); Phillips 66 Company (Phillips 66); SOLVAY Specialty Polymers USA (Solvay); and Tokai Carbon CB, Ltd. (Tokai).

All commenters supported parts of the rules but commented against other parts, and all commenters suggested changes to parts of the rules. Except for the EPA and Solvay, the requested changes were limited to the parts of the rule applicable to the commenting company.

Response to Comments

General

Comment

Tokai, CP Chem, and Phillips 66 supported the overall objectives of the rulemaking. Alon expressed general support for the rulemaking and its practical approach to attainment. Tokai and Arcosa expressed appreciation for the staff's willingness to develop a flexible approach to ensuring attainment. Solvay expressed support for the state to meet its regulatory obligations. CP Chem noted that it shared the TCEQ's goal of achieving the SO_2 NAAQS in Hutchinson County. Tokai supported the proposed emission limits; and Phillips 66 commended staff's efforts.

Response

The commission appreciates the commenter's support.

Comment

Tokai requested changes to the rules to address technical corrections, provide additional flexibility, and remove requirements that are unreasonable or otherwise exceed federal standards. Alon provided requested rule changes to enhance rule clarity, ensure consistency and alignment with other applicable federal regulations as well as create some efficiencies without compromising attainment of the SO_2 NAAQS. Phillips 66 and CP Chem commented that the rules should be modified to address infeasible requirements, provide compliance flexibility that does not impact the goal of NAAQS attainment, and improve the overall clarity of the rules. Solvay commented that the rule should be adjusted to ensure that they can continue to make timely adjustments to operations to meet ever-changing market conditions. CP Chem commented that the rule should be modified to address infeasible requirements, provide compliance flexibility that does not impact the goal of NAAQS attainment, and improve the overall clarity of the rules.

Response

The commission appreciates the comments and has addressed specific comments as discussed elsewhere in this response to comments, providing flexibility where appropriate.

Comment

Arcosa provided revised cost information for the Fiscal Note, showing their control devices would cost $10 million to install with annual operating costs at $500,000. Arcosa also provided compliance testing and monitoring cost estimates of approximately $100,00 per year.

Response

The commission appreciates the information on the estimated costs to install control devices on a lightweight aggregate kiln. However, it is not clear from Arcosa's comment what type of control is associated with these costs or that they correspond to the control device(s) that will be installed. The information Arcosa provided indicates that the cost estimates in the proposal fiscal note greatly overestimated the capital costs and annual operating costs for Arcosa, so the fiscal impact will be less than anticipated. No change to the rules was made in response to this comment.

Comment

Tokai commented that the TCEQ should conduct the required Takings Impact and Regulatory Impact Analyses. Tokai also commented that to the extent that the TCEQ exceeds its own authority, imposes technically infeasible requirements, or otherwise requires more than is necessary to comply with the FCAA, it disagrees with the TCEQ's position that it is exempt from statutory safeguards on administrative process. Similarly, Phillips 66 commented that the Takings Impact and Regulatory Impact Analyses are required because some provisions exceed federal requirements or render compliance impracticable as described in their comments on the rules, as discussed elsewhere in this response to comments.

Response

The commission disagrees that Takings Impact and Regulatory Impact Analyses are necessary for the reasons stated in the adopted rules. The commenters provided no evidence that the commission is exceeding its authority. The commission has addressed comments made regarding the technical or practical infeasibility of the rules elsewhere in this response to comments and does not agree that the adopted rules pose technical or practical infeasibility issues; therefore, the rules have no effect on the Takings Impact and Regulatory Impact Analyses. As indicated elsewhere in this preamble, the rules are no greater than what is necessary to comply with the FCAA requirement to adopt SIPs to ensure attainment and maintenance of the SO_2 NAAQS and are designed to significantly advance that health and safety purpose. The adopted rules require only what is necessary to comply with the FCAA, as demonstrated by the air dispersion modeling and technical analysis provided in the SIP revisions associated with these adopted rules; therefore, they do not impose a greater burden than is necessary to achieve the health and safety purpose, nor do they exceed a standard set by federal law or state

law. Thus, these adopted rules are not subject to the requirement to prepare a Regulatory Impact Analysis under the Tex. Gov't Code, §2001.0225 or a Takings Impact Assessment under the Tex. Gov't Code, Chapter 2007. No change was made in response to these comments.

Comment

Tokai supported changes to the rules to address technical corrections, provide additional flexibility, and remove requirements that are unreasonable or otherwise exceed federal standards. Alon provided requested rule changes to enhance rule clarity, ensure consistency and alignment with other-applicable federal regulations as well as create some efficiencies without compromising attainment of the SO2 NAAQS. Phillips 66 and CP Chem commented that the rules should be modified to address infeasible requirements, provide compliance flexibility which does not impact the goal of NAAQS attainment, and improve the overall clarity of the rules. Solvay commented that the rule should be adjusted to ensure that they can continue to make timely adjustments to operations to meet ever-changing market conditions. CP Chem commented that the rule should be modified to address infeasible requirements, provide compliance flexibility that does not impact the goal of NAAQS attainment, and improve the overall clarity of the rules.

Response

The commission appreciates the comments and has addressed specific comments as discussed elsewhere in this response to comments, providing flexibility where appropriate.

Comment

Phillips 66 commented that the citation of the EPA's 2014 guidance document for RACT/RACM requirements is incorrect because the requirements arise from 40 CFR §51.100(o), which makes clear that controls must be reasonably available, including both necessary and reasonable for their social, environmental impacts. Many of the changes suggested by Phillips 66 for the Subchapter F Division 4 rules were based on concerns that the proposed requirements are not necessary or feasible and reasonably available, or do not account for social, environmental, or economic impacts.

Response

The commission notes that, while 40 CFR §51.100(o) defines RACT, the EPA's 2014 guidance document provides greater specificity on implementing RACT and RACM for SO_2 nonattainment areas. In evaluating the provisions in these rules, the commission worked with the affected companies to determine the most reasonable way of achieving attainment in the attainment demonstration modeling. The commission understands the societal and economic impacts on the affected companies are in some cases large but also understands the impacts to public

health of not attaining the NAAQS and the potential impacts to the affected companies if an approvable SIP is not submitted to the EPA. To find emission rates and stack parameters that allowed an attainment demonstration through modeling, the commission worked with the companies in each nonattainment area to identify the appropriate sources to include in the rules and the emission limits and stack parameters that would model attainment. In some cases, similar sites requested different approaches. In other cases, the approaches favored by the company did not model attainment without changes. The commission proposed emission rates and stack parameters that were intended to meet the EPA's guidance for complying with the FCAA for SO_2 nonattainment areas, which discusses the statutory requirement (FCAA, §172), as well as national and regional measures that may fulfill RACT/RACM in addition to discussing source specific emission limitation concerns. The EPA guidance does not conflict with the requirements of 40 CFR §51.100(o). The commission considers the provisions in the rules to be both necessary for modeling attainment and feasible for the companies and has considered social, environmental, and economic impacts in promulgating the proposed rules.

Comment

The EPA commented that the rules (§§112.107, 112.117, 112.207, 112.217, 112.227, 112.237, 112.247, and 112.307) should be revised to clarify that contingency measures are also triggered upon failing to meet RFP and that evaluation or investigation of monitored exceedances would be beneficial to understand the problem and would allow consideration of changes to processes, work practices, emission rates and monitoring that would be beneficial.

Response

In response to this comment, language was added to all the contingency measure provisions to specify that the contingency measures will also be triggered if the EPA finds that a nonattainment area failed to meet RFP. Additionally, changes to the rule provisions are made to specify the factors to be covered in all full system audits and in those required because the EPA determined a failure to attain based on ambient air monitor data or on modeling. The TCEQ notes that all sites address in the rules are subject to the Title V Operating Permits Program which provides additional compliance tools that, in conjunction with other aspects of the compliance and enforcement program, will ensure attainment is reached as expeditiously as practicable. The TCEQ's robust enforcement program, exceedance reports in the associated rules, Title V deviation reports, and Title V compliance certifications will be used to investigate and address exceedances and violations of permit limits.

Comment

The EPA commented that compliance with the SO_2 NAAQS is required as expeditiously as possible and that there should be detailed discussion of the January 1, 2025 compliance date is appropriate for each of the rule divisions and Subchapter G. To satisfy RFP, the earliest compliance date achievable is required. The EPA requested that the TCEQ provide more explanation and rationale for how the selected compliance dates for affected sources in Howard, Hutchinson, and Navarro Counties satisfy this requirement.

Response

In response to this comment, the TCEQ has reevaluated the compliance dates to ensure that compliance is achieved as soon as practicable. The compliance dates depend on site specific constraints, as well as other considerations such as global supply chain delays. The basis for the compliance dates for each site is discussed in the response to comments for each section.

Comment

The EPA commented that in each rule division and Subchapter G, the compliance and monitoring requirements should include the methods and equations used to calculate emissions when they are not directly measured with an instrument and that details on monitoring that are consistent across the rules should be provided that specify the manner, form, accuracy of data, number of samples required, etc.

Response

In response to this comment, the TCEQ added additional details and clarity regarding monitoring requirements in several sections. Where appropriate, equations were added for calculating emission rates, and consistency within the rules was improved.

Comment

The EPA expressed its preference for hourly data collection and calculation because it matches the one-hour NAAQS.

Response

In response to this comment, the mass balance calculations relying on weekly sampling in Subchapter G were replaced with the requirement to install a CEMS, and the frequency of sampling at the carbon black plants was increased from once per day to twice per day. The use of continuous sulfur analyzers at the carbon black plants was evaluated, but the measure was found to be cost prohibitive (costing about $1.3 million to provide continuous sulfur analyzers for each tail gas stream at both Tokai carbon black plants. Additionally, there is concern that the monitors may become clogged or damaged and require frequent repair or replacement. Because the emissions from the Orion site are monitored with a CEMS, with the exception of emissions from the flare, which is infrequently used the additional

cost of a continuous sulfur analyzer is even less justifiable.

Comment

The EPA commented that evaluation of CEMS should be done for all sites (especially for Arcosa) or, when CEMS cannot be easily installed and unless technically or cost prohibitive, post-combustion analyzers should be required for continuous monitoring of total sulfur content and flow rate of exhaust gases.

Response

An evaluation was completed, and it was determined that a CEMS is not appropriate for all sites or for all sources subject to these rules. For example, the only affected emission sources at CP Chem are fugitive emissions and flares, neither of which can be monitored with a CEMS. As previously discussed in this response to comments, continuous sulfur analyzers were evaluated for the carbon black sites which are the only sites not required to collect continuous sulfur concentration data in the proposal. Continuous sulfur analyzers for the carbon black plants were determined to be cost prohibitive and potentially difficult to maintain. Instead of requiring continuous analyzers for these sites, the frequency of sampling carbon black oil is increased from once per day to twice per day and performance testing once every 5 years is now required in order to collect additional compliance information for the carbon black sites without CEMS.

Comment

The EPA commented that throughout the rules, any ASTM method cited should be to the most current version and should be relevant to the feed being tested. The EPA further stated that justification should be provided on why the use of a nonrelevant method is appropriate and how it is equally stringent for measuring SO_2 emissions.

Response

Based on this comment, the dates associated with referenced test methods were removed from the rules to no longer specify a version and to allow use of updated versions in the future. The agency reviewed the ASTM methods, made revisions where appropriate, and confirmed that all methods in the adopted rules are relevant to the feed being tested.

Comment

The EPA recommended updating the first subsection of each rule section for control requirements (§§112.102, 112.112, 112.202, 112.212, 112.222, 112.232, 112.242, and 112.302) to clarify that the phrase "prior approval of the executive director and [the] EPA" meaning that the formal SIP revision and approval process must be followed and provided specific rule language for consideration.

Response

The commission does not agree that a full SIP revision is the only mechanism available under the FCAA for making minor revisions to rule requirements adopted as part of the SIP. The EPA previously approved provisions that allow making changes in other rules that were adopted as part of the SIP, including the AMOC program in 30 TAC Chapter 115 Subchapter J Division 1 and the alternate control provisions in 30 TAC §115.725(m). However, in response to this comment the TCEQ removed this provision and is instead identifying the site by its location and the EPN by the name of the sources in the New Source Review permit.

Comment

The EPA commented that in §§112.102, 112.112, 112.202, 112.212, 112.222, 112.232, 112.242, and 112.302, the requirements for a full system audit should include all SO_2 sources identified in the site's NSR permit. The EPA commented that, in addition to triggering based on monitoring data, the requirements should be triggered by a determination that a nonattainment area failed to achieve attainment based on review to other available information, including modeling and compliance data.

Response

As discussed previously in this preamble, the TCEQ has identified all significant sources in the SO_2 nonattainment areas based on whether their emissions impact

any receptor at or above the SIL; as a result, those sources are the sources that should be the focus of an FSA. In addition, a determination of failure to attain based on other information such as modeling or compliance information should not automatically require an FSA because these instances of failure to attain will be addressed by existing programs including the compliance and enforcement program and Title V.

Comment

The EPA commented that the recordkeeping provisions in §§112.106, 112.116, 112.206, 112.216, 112.226, 112.236, 112.246, and 112.306 should all be consistent and that the requirements should be more prescriptive. This includes specifying the type of units to use for measurements and calculated emissions as well as the format and layout for keeping the records. The EPA also commented that records should be kept of the accuracy of measurements and methods used for its verification. The EPA also provided specific rule language additions for consideration.

Response

In response to this comment, the commission revised the proposed recordkeeping rules to clarify that records can be kept in either electronic or hard copy format. The commission also included emission calculations for determining emission rates in lb/hour where appropriate, including the units to be used in the equations, and

accuracy specifications for monitoring equipment.

Comment

The EPA commented that §§112.100, 112.110, 112.200, 112.210, 112.220, 112.230, 112.240, and 112.300 should be clarified regarding whether the rules apply only to the units listed in subsection (b) of each rule or to all units in the sites' permits. The EPA noted that some units associated with the listed emission sources are mentioned in the rules but are not covered in the respective applicability section and suggested that all sources within each production unit be included as applicable. The EPA further commented that in subsection (a) of each of the applicability sections should clarify whether the prohibition on changing EPNs and RNs applies to all RNs and EPNs in the permit or only to the listed units.

Response

The affected sources are identified by the EPN to which the emission limits apply. However, monitoring, recordkeeping and reporting requirements may apply to raw materials or process streams that generate emissions from the identified EPNs. The prohibitions on changing RNs and EPNs were removed because sites are no longer identified by RNs but instead by addresses or latitude and longitude, and sources are identified by the EPN name on the MAERT issued on the identified date.

Comment

The EPA commented that in the definitions sections in each rule division and Subchapter G, definitions should be added for the following terms: actual emissions (recommended to be "monitored emissions using a CEMS or a monitoring device that directly measures the emissions from an affected source and determined without the use of any mass balance calculations"); calculated emissions (to differentiate from actual emissions); continuous monitoring; continuous emissions monitoring system; raw materials; refinery gas stream; and waste gas. The EPA commented that the definition of any term not used be removed from the respective definition section if it is not used in that rule division or Subchapter G.

Response

The TCEQ removed the term "actual emissions" and instead refers to emission calculations where emissions are not directly measured. The TCEQ also specified that continuous monitoring is monitoring at least every 15 minutes, consistent with the federal definition. The term "raw materials" is no longer used due to the replacement of periodic sampling with continuous monitoring. The term "waste gas" was removed from the rule to identify more clearly to which streams the requirements apply. As specified in each definition section, all terms have the meanings commonly used in the field of air pollution control unless they are specifically defined in the Texas Clean Air Act (Texas Health and Safety Code, Chapter 382), or in 30 TAC §101.1 or §112.1.

Comment

The EPA commented that the rules do not describe how or when MSS activities are authorized and should clearly describe what MSS activities are authorized, the process for authorizing them, and recordkeeping requirements to identify the MSS periods in which the MSS emission limits apply.

Response

The commission made no change in response to this comment. MSS activities are authorized through case-by-case permits, standard permits, or permits by rule under the NSR program. The activities authorized as MSS are identified through the NSR program, and it is neither appropriate nor necessary to define what activities are or are not authorized through the NSR program in these rules. Similarly, upsets are governed by Chapter 101 and are not included or defined under this chapter.

Comment

The EPA requested that the TCEQ provide an assurance that the proposed flare emission limits apply only to MSS periods and not to upsets or periods of malfunctions. The EPA further commented that the TCEQ should clarify that the analysis of historical events supporting development of emission limits and number of operating days for MSS periods does not include any malfunction events.

Response

The emission limits in the rules apply only to authorized emissions. Air permits authorize normal unit operation and planned MSS activities pursuant to 30 TAC Chapter 116. Authorized emission limits and permit conditions are based on application representations of unit operations and planned maintenance activities. Requirements for emissions events and emissions due to unscheduled activities are addressed in 30 TAC Chapter 101, Subchapter F, Divisions 1 and 2.

Comment

The EPA commented that the screening out from inclusion in the rules of some sources at a 3 ppb threshold at the maximum design value in the attainment demonstration modeling is not protective of the NAAQS because those excluded sources would change emission limits or stack parameters resulting in exceedances of the NAAQS. The EPA commented that all sources included in the modeling must have enforceable limits. The EPA stated that the TCEQ did not document how the 3 ppb level is protective but relied on this threshold as an interim SIL in permitting to evaluate impacts from all sources at a site rather than on a unit-by-unit basis. The EPA noted that the use of the SIL in permit modeling evaluates cumulative emission increases for all ambient air receptors rather than for individual sources at only the maximum design value receptor, such that the cumulative from multiple units at a site could represent a significant portion of the 75 ppb NAAQS. The EPA commented that the maximum design value in the attainment demonstration for Howard County is 72 ppb and for Hutchinson County is 74.9 ppb, meaning that only small increases could exceed the NAAQS, and that there are many receptors within a few ppb of the NAAQS.

Response

The commission clarifies that the attainment demonstration modeling included all sources in each nonattainment area and a cumulative impact of emissions from all sources was simulated at all ambient receptors. For inclusion into the rules, the impact of each individual source was evaluated at all ambient receptors in the modeling domain and not only at the maximum design value receptor, as the EPA mistakenly stated in its comment. Because the SIL is used in other SIP-approved programs to identify the sources with the most significant impacts, it is a reasonable threshold for determining which sources are most likely to impact attainment of the NAAQS. No change to the rule was made in response to this comment.

Alternative SO_2 Emission Limit

Comment

The EPA commented that these subsections 112.102(j), 112.112(j), 112.202(d), 112.212(e), 112.222(g), 112.232(l), 112.242(k) and 112.302(g), must be revised to accurately reflect FCAA requirements for SIP revisions (reasonable notice and public hearing) and provided suggested revised regulatory text for the proposed rules. The EPA recommended each subsection be revised to require both Executive Director and

EPA approval of any alternate emission limits as well as any deviations from the attainment demonstration modeling methodology through submission of a SIP revision by the executive director. The EPA also commented that any changes must satisfy FCAA §110(l). In response to the commission's solicitation of comments on whether an additional mechanism to request alternative SO_2 emission limits similar to the 30 TAC Chapter 115, Subchapter J, AMOC rules could be used to establish an intra-plant trading program would be appropriate, the EPA commented that intra-plant trading is not an appropriate method of control for these sources. The EPA stated that the inclusion of provisions that allow for alternate emission limits to be established outside the required FCAA SIP revision process is not approvable.

Response

The commission removed the alternative SO_2 emission limit provisions in proposed §§112.102(j), 112.112(j), 112.202(d), 112.212(e), 112.222(g), 112.232(l), 112.242(k) and 112.302(g). The commission added an AMOC process in new Subchapters E and F, as requested in comments submitted by Phillips 66 and supported by Tokai, Solvay and CP Chem, which are similar to EPA-approved AMOC rules in 30 TAC Chapter 115. A procedure for allowing sources to make changes to emission limits that result in equivalent or lower emissions was already approved by the EPA into the Texas SIP. This procedure is found in the 30 TAC Chapter 115 AMOC rules (30 TAC §§115.910 – 115.916). In approving these rules in 1997, the EPA stated that the AMOC provisions meet the requirements of the FCAA by requiring "greater

emission reductions for alternate control methods…**a public comment period and** … **EPA approval/disapproval." (*see* Clean Air Act Limited Approval of Volatile Organic Compound (VOC) Control Measure for Texas, 62 Fed. Reg. 27964, 27965 (May 22, 1997).**

Comment

Phillips 66 commented in support of making an AMOC mechanism patterned after SIP-approved AMOC provisions in 30 TAC Chapter 115 available for alternate SO_2 emission limits as proposed in 30 TAC §112.232(l). Phillips 66 urged the TCEQ to include an AMOC program that allows sites to make changes to affected sources that are protective of the attainment demonstration modeling without requiring a SIP revision. Phillips 66 further commented that flexibility on unit-specific emission limits without the delay and uncertainty of a full SIP revision is vital to the viability of the Borger Refinery in the fuels market and would incentivize environmentally beneficial projects while a lack thereof disincentivizes them. Phillips 66 provided an example of an environmentally beneficial project that would not be possible without provisions for an AMOC. Phillips 66 provided a suggested AMOC process and rule language, which they state provides for a narrow range of projects that parallels the EPA-approved AMOC provision in 30 TAC Chapter 115 while requiring a demonstration that the modeled impacts of all emission units affected by the trade have no net increase in ground-level concentration along with procedural requirements, public process, and authority for the Executive Director to approve minor changes to monitoring, reporting, recordkeeping and testing. Therefore, Phillips 66 commented that the suggested AMOC process is consistent with the FCAA and federal caselaw, citing to *United States v. General Motors Corporation*, 702 F. Supp. 133, 135 (N.D. Tex. 1988).

Tokai commented that it expects the EPA would disapprove §§112.112(j) and 112.242(k), which would allow Tokai to request alternative SO_2 emission limits because these subsections imply EPA approval without a formal SIP revision. Tokai commented that an AMOC is its preferred approach to setting alternative emission limits. Tokai stated the approach should extend to changes in emission point locations and stack heights and requested that a plan based on the AMOC provisions in 30 TAC Chapter 115, Subchapter J be developed with changes as needed. Tokai stated that AMOC plans are consistent with the FCAA if they meet procedural requirements and EPA's implementing regulations and do not constitute SIP revisions but are rather a discretionary economic incentive program as codified in 40 CFR Part 51 Subpart U. Tokai stated that, similarly to the SIP-approved AMOC provisions in 30 TAC §115.725(m) and elsewhere, the executive director should be allowed to approve minor changes to monitoring, recordkeeping, reporting and testing requirements. Tokai commented that a streamlined dispersion modeling process should be provided that does not require recreating TCEQ's full attainment demonstration modeling and that is based on the net change in ground level SO_2 concentrations such as the highest first-high modeled concentration because this approach would provide greater environmental benefit than the full SIP revision process. Tokai stated that the AMOC provisions should be limited to the executive director alone approving minor modifications of test and monitoring methods, which states are routinely given authority by EPA to grant, because there is not streamlined EPA approval process for modifications.

Solvay commented that the AMOC provisions should be added to the rule as another process to request alternative SO_2 emission limits as provided in 30 TAC §112.232(l) and expanded to allow trading of emission reductions for contiguous sites, which would allow the most efficient use of capital to achieve reductions.

CP Chem urged the TCEQ to include the AMOC program regulatory language suggested by Phillips 66 that will allow stationary sources to make changes to SO_2 emitting EPNs that are protective of the attainment demonstration without requiring a SIP revision.

Response

The commission made changes to the alternative emission limits subsections in Subchapter E and F to reference rule text to add an opportunity for an AMOC process, as discussed in the section-by-section portion of this preamble. The commission agrees that the proposed language in §§112.102(j), 112.112(j), 112.202(d), 112.212(e), 112.222(g), 112.232(l), and 112.242(k), did not provide the necessary steps to ensure that changes to emission limits established in the rule would be protective of the NAAQS. Additionally, the proposed language did not specify public participation procedures. The commission agrees with the commenters that the AMOC process requested by Phillips 66, which is based on the

EPA-approved rules in 30 TAC Chapter 115 will provide sources flexibility to make future changes at their plants while ensuring attainment of the SO_2 NAAQS is not jeopardized.

This AMOC process adopted in this rule provides the necessary public, TCEQ and EPA review as well as requiring a conservative dispersion modeling demonstration ensuring changes in emissions will maintain SIP integrity and NAAQS protectiveness. An increase in the pound per hour emission limit for a source subject to the control requirements is allowed if the AMOC also includes an equivalent decrease in the pound per hour emission limit for one or more sources subject to the rules. An AMOC provision incentivizes environmentally beneficial projects while a lack thereof disincentivizes them because a SIP revision would be needed before any changes can be made to sources covered by these rules. Further, the AMOC process is not a substitute for authorization of new emissions through the NSR program. All required authorizations must still be obtained as required by TCEQ rules.

<u>Subchapter E Division 1 (Alon)</u>

General for Division 1

Comment

Alon commented that the citations throughout the division to federal requirements in

40 CFR Part 60, Subpart Ja should be changed to "the currently applicable federal requirement" because the FCCU and SRUs are currently subject to the federal requirements in 40 CFR Part 60. Subpart J. Alon stated that under their consent decree with the EPA, it could choose to comply with Subpart Ja in the future and that the wording change would still accomplish the intent of the provisions.

Response

The proposed rules were based on compliance with the modeled emission limits in the attainment demonstration emission limits and not the currently applicable federal rules. Additionally, staff identified specific concerns that would result from relying solely on a general reference to 40 CFR Part 60, Subpart J (Subpart J): 1) Subpart J does not contain a method to calculate pound per hour SO_2 emissions; 2) FCCU and SRU concentration limits in Subpart J will not establish compliance with proposed rule pound per hour SO_2 emission limits; 3) Subpart J has monitoring provisions for FCCU alternative coke burn-off (instead of H_2S and SO_2 concentrations) for units without add-on control, which would not generate sufficient data to determine pound per hour SO_2 emissions; 4) Subpart J authorizes SRU total reduced sulfur continuous parametric monitoring for units with reduction controls not followed by incineration, compared to the more accurate CEMS in the proposed rule; 5) the EPA commented that the monitoring provisions should contain more prescriptive language to describe calculations and methods used to derive pound per hour SO_2 emissions, which do not appear in Subpart J; 6) a general

reference to applicable federal requirements would not provide the same data quality, level of accuracy, or compliance determination assurance as the proposed rules; and 7) NSPS J or Ja both contain MSS exemption from emission monitoring standards that are not appropriate for rules intended to enforce MSS SO_2 pound per hour emission limits. Therefore, a general reference to federal rules, which are designed to enforce concentration limits, would not be as accurate or effective in determining pound per hour SO_2 compliance as the proposed rules. No change to the rules was made in response to this comment.

§112.100

Comment

Alon agreed with the applicability sentence and change of ownership provision in §112.100(a) but commented that the last sentence ("Once approved by the United States Environmental Protection Agency (EPA), the requirements in this division continue to apply until the EPA approves their removal.") should be deleted because it is not needed to convey that the EPA authority over provisions in approved SIPs and implies that the TCEQ could continue to enforce the provision even if it is repealed, which exceeds the agency's authority.

Response

The commission disagrees with the commenter's assertion that the agency will

enforce rules that are repealed; however, to avoid confusion this language has been removed at adoption. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

§112.102

Comment

Alon requested TCEQ revise §112.102(c) to simply state the four MSS flares must comply with 40 CFR Part 60, Subpart Ja requirements. The inclusion of the 162 ppmv limit from Subpart Ja in the rules makes that limit applicable at all times, although under Subpart Ja it does not apply during upsets. The inconsistency with the existing federal requirement would inadvertently create new conflicting requirements and/or limit options. The concentration limit was not used for the attainment demonstration modeling.

Response

In response to Alon's concern that it is not technically feasible for MSS flare activities to meet the 162 ppmv standard, the commission is adding the phrase

“during normal operations” to the to the end of §112.102(c).

Comment

Alon commented that the FCCU and SRUs’ applicability references throughout the division to federal requirements in 40 CFR Part 60, Subpart Ja should be changed to “the currently applicable federal requirement” because the FCCU and SRUs are currently subject to the federal requirements in Subpart J. Alon stated that under its decree with the EPA, it could choose to comply with Subpart Ja in the future and that the wording change would still accomplish the intent of the provisions.

Response

In response to Alon’s comment and EPA comments about the need to clearly specify monitoring and other regulatory requirements, the commission is revising §112.102(c). The updated language specifies the requirements applicable to the FCCU and SRU and contain some of the same monitoring methodology but does not duplicate verbatim the federal rule provisions in 40 CFR Part 60, Subpart Ja. The proposed Chapter 112 rules are designed to enforce the emission limits (during both normal and authorized MSS operation) used in the Howard County attainment demonstration modeling. Flare and other combustion equipment parametric monitoring provisions are authorized in the rule for sources that present inherent direct SO_2 exhaust monitoring difficulties and contain allowable methods to

measure the total sulfur content of the precombustion feed stream and use it to calculate the resultant SO_2 combustion emissions. Minimum parametric monitoring requirements to verify compliance include a total sulfur or H_2S analyzer, totalizing flow meter and temperature measurement instrumentation. The federal requirements in Subparts J and Ja limit gaseous hydrocarbon streams combusted in both attainment and nonattainment area refineries to 162 ppmv H_2S during normal operations, rather than providing pound-per-hour values like proposed Chapter 112 rules, and only require an H_2S monitor. It is not sufficient or feasible to determine compliance with the rules by generically referencing Subpart Ja or "currently applicable federal requirement" methodology for the concentration limits for the rules.

§112.103

Comment

Alon requested the TCEQ revise §112.103(2) to state the flares must only comply with Subpart Ja monitoring provisions. The proposed rule requires monitoring during upsets, which is not required by Subpart Ja. The inconsistency with the existing federal requirement would inadvertently create new conflicting requirements and/or limit options.

Response

The change requested by Alon is not appropriate for this rule. Supplemental language is added to the rule to address the EPA's concerns that the monitoring specifications are not prescriptive enough to fully describe the necessary flare monitoring requirements. It would be inappropriate simply require 40 CFR Part 60, Subpart Ja flare monitoring provisions that are intended to verify flare normal operations compliance with a 162 ppmv H_2S concentration limit, rather than monitoring methodology that is intended to verify flare compliance with rule limits that apply during both normal and MSS operations on a pounds-per-hour basis. A total sulfur analyzer and dedicated flow meter are the most accurate methodology to monitor flare compliance during MSS and normal operations, and provisions are added to the proposed rule for this purpose, as well as an alternative method of monitoring H_2S as surrogate parameter to quantify SO_2 emissions.

Comment

Alon commented that the provisions in §112.103(1) - (3) are unclear on how they apply to flow monitoring devices and that the provisions should be amended to allow the use of best engineering judgement when data from flow measurement devices is lost or invalid. Because flow monitoring does not have conventions for calculating downtime, §112.103(a)(4) should not require 95% uptime. The rule also does not state the time period for attaining the 95% uptime; for consistency with federal CEMS requirements, the period should be semiannually. Because of the complexity of flow monitoring and sulfur analyzers for flares, the uptime requirement for those should be 90%.

Response

The TCEQ evaluated Alon's request to reassess and clarify monitoring requirements. Additional monitoring instrument and accuracy language is added to clarify §112.103(1) - (3) provisions. Engineering judgment provisions are kept in §112.103(4) so this method may be employed to satisfy data substitution requirements as requested. The TCEQ determined that the 95% monitoring instrument uptime provisions, which are similar to federal rule and state new source review requirements, represent an appropriate and reasonable standard for proposed §112.103(4) requirements. Therefore, the 95% monitor uptime requirements are maintained in §112.103(4).

Comment

Alon requested the TCEQ delete §112.103(4) provisions requiring a minimum of engineering judgement be employed to replace invalid or missing monitoring data in determining pound per hour SO_2 emission limit compliance.

Response

Requiring a minimum of engineering judgement is a reasonable and appropriate standard that is consistent with other state and federal requirements. No change was made to the proposed rule in response to this comment.

§112.104

Comment

Alon commented that the monitoring devices required by §112.103 have been in place for several years, so the initial testing requirement in §112.104(2) should exclude monitors that have had previous testing.

Response

The provision in §112.104(2) only requires initial testing that was conducted in accordance with the manufacturer's specifications. If prior testing of existing monitors was done according to manufacturer's specifications, the provision does not require any action. However, if prior testing was not in accordance with the manufacturer's specifications, the monitor must be retested to ensure that it is calibrated and functions properly. The rule language was clarified to better depict these requirements.

§112.105

Comment

Alon commented that including the ASTM methods in §112.105(b) is unnecessary and redundant because continuous monitoring of SO_2 emissions and of the sulfur content of flared gases is required.

Response

The test methods are needed for determining the sulfur content of fuel during the testing specified in §112.104. No change to the rule was made in response to this comment, but additional test methods are added for consistency between the requirements for the two refineries.

§112.107

Comment

Alon requested the TCEQ change the 90-day deadline (March 31st) in §112.107(a) for reporting exceedances and noncompliance to 135 days (May 15th) to better align with other state and federal reporting requirements.

Response

Exceedance reports are needed in a timely manner, and 90 days after the year in which the exceedance occurs provides sufficient time to report. If the deadline for submitting the report were extended to May 15, it could be up to 16 months between the time an exceedance occurred and the TCEQ was notified. More timely notification is needed to ensure compliance with the rules. No change to the rule was made in response to this comment.

Comment

Alon stated concerns that the full system audit in §112.107(c) is not appropriate for Howard County because it does not know the emissions from other sites and therefore cannot determine the source of an exceedance. For cases where modeling is required for an audit, the 90-day deadline in §112.107(c) for submitting the audit results should be extended to 180 days.

Response

TCEQ considers 90 days to be adequate time for the completion of a full system audit since Alon will not be responsible for submitting modeling or information from other sites as part of this audit.

§112.108

Comment

Alon commented that the phrase "as soon as practicable" should be deleted from §112.108 to avoid uncertainty on when control measures must be in place.

Response

The commission has evaluated the compliance dates for each site, and determined

that each date, revised as appropriate, is as expeditiously as practicable. As a result, this language was deleted.

Comment

The EPA stated it is unclear when the control requirements of §112.108 would require installation of controls or other reductions and modifications. The language indicates the owner or operator must comply with the requirements "as expeditiously as practicable, but no later than January 1, 2025." There is no discussion of how soon Alon can comply with the new emission limits nor a discussion and rational of why several years are necessary to achieve compliance with the emission limits. It is important to get the reductions in place as expeditiously as practicable in order to achieve attainment because the monitored design value that will be part of the basis of determining attainment or nonattainment is based on three consecutive years of data. The EPA noted that other areas which require longer times for compliance provide dates and RFP achievements as a demonstration that they are satisfying the "as expeditiously as practicable" requirement.

Response

Alon indicated that it can comply with the requirements for the FCCU (EPN 06ESPPCV) and the SRU incinerators (EPN 69TGINC and EPN 71TGINC) by November 1, 2023, but that complying for other sources may take until January 1,

2025. The January 1, 2025 compliance date for requirements associated with the flares is necessary to make physical and operational changes needed to comply with control and monitoring requirements in Subchapter E. Therefore, the rule is revised at adoption to provide an earlier compliance date for the FCCU and SRU incinerators. Because the soonest practicable dates for compliance are identified in the rule, the term "as soon as practicable" was removed at adoption.

Comment

The EPA stated that in background and summary portion of the proposed rulemaking, the TCEQ mischaracterized their comments regarding averaging times longer than one hour in the 2014 SO_2 SIP guidance.

Response

In response to this comment the discussion of longer averaging times has been updated consistent with the EPA's comments.

<u>Subchapter E Division 2 (Tokai)</u>

§112.110

Comment

Tokai requested TCEQ delete §§112.110(a) and 112.240(a) that contain the following provision: "Once approved by the [EPA], the requirements in these rules continue to apply until the EPA approves their removal." This requirement provides that TCEQ may enforce the rules after they are repealed or alternately, that TCEQ may not repeal the rules without EPA permission. Tokai stated that it doubts TCEQ has authority to promulgate such a requirement and should delete §§112.110(a) and 112.240(a) and similar provisions in Chapter 112.

Response

The commission disagrees with the commenter's assertion that the agency will enforce rules that are repealed; however, to avoid confusion this language has been removed at adoption. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

§112.112

Comment

The EPA commented that the emission limits for various furnace operation scenarios should be revised for clarity to state how and when the limits apply and how the table should be interpreted, including how each column correlates to a specific operational scenario, or whether each column is separately enforceable as an operating scenario. For the requirement that the fewest number of furnaces on-line be used to calculate an emission limit, clarify if this means the total number of furnaces in operation at any time or if it applies to an individual set of production units or if one set of production units controls the emission limit used for the scenarios, and if less units do not equal less emissions, the provisions should specify whether the lower emissions rate or the number of production units control the emission limit used for that scenario.

Response

The number of furnaces on-line in each production unit determines the set of emission limits that apply. The number of furnaces in operating units one and two should be combined to identify the appropriate rows that could apply based on the first column. Then the number of furnaces in production unit 3 should be determined to identify which of those rows is the exact row containing the set of emission limits that apply during any one hour. For example, if there are two furnaces on-line in production unit 3, three furnaces on-line in production unit 1 and no furnaces on-line in production unit 2, the emission limits would be 519.42 lb/hr for the overall cap, 436.23 lb/hr for EPN 13A or Flare 4, 156.02 lb/hr for EPNs 7A and 12A combined, and 73.00 lb/hr for EPN 12A. The provision specifying that the fewest number of furnaces on-line should be used to determine the emission rate was clarified to reflect that fewest number of furnaces on-line in each

production unit should be used to determine what the emission limit is during transition periods. Another option for determine the appropriate emission limit during these periods is also provided in response to a comment from Tokai. The TCEQ also removed the redundant monitoring requirement regarding measuring the volumetric flow rate to the dryers. The inadvertent typographical errors are corrected in the rule and figure. In response to this comment additional language was added to this provision for clarity. The number of furnaces on-line in each production unit determines the set of emission limits that apply in any one hour. Each row represents a different operating scenario and each cell in the tables is enforceable based on the number of furnaces on-line in any hour. The number of furnaces in operating units one and two should be combined to identify the appropriate rows that could apply based on the first column. Then the number of furnaces in production unit three should be used to identify which of those rows is the row containing the set of emission limits that apply during any one hour. For example, if there are two furnaces on-line in production unit three, three furnaces on-line in production unit 1 and no furnaces on-line in production unit two, the emission limits would be 519.42 pounds per hour for the overall cap, 436.23 pounds per hour for EPN 13A or Flare 4, 156.02 pounds per hour for EPNs 7A and 12A combined, and 73.00 pounds per hour for EPN 12A. The provision specifying that the fewest number of furnaces online should be used to determine the emission rate was replaced with an equation that determines the appropriate emission limits based on the time weighted average of any set of emission limits that could apply in any minute of an hour.

Comment

Tokai requested TCEQ delete all entries in Figure 30 TAC §112.112(b) specifying an emission limit where only one (1) furnace is on-line. Units 1 and 2 cannot operate with exactly one (1) furnace on-line, nor can Unit 3. Tokai disagreed with the inclusion of impossible operating scenarios in the table of emission limits. Since their modeling would entail the use of hypothetical discharge parameters in the Attainment Demonstration modeling, Tokai applauds the apparent absence of such scenarios from the Modeling TSD (Appendix K of SIP revision).

Response

The entries in proposed Figure 30 TAC §112.112(b), which is re-lettered as Figure 30 TAC §112.112(b) at adoption. specifying an emission limit where only one (1) furnace is on-line are deleted at adoption, and a prohibition on operating either Units 1 and 2 or Unit 3 with only one furnace is added to re-lettered §112.112(a).

Comment

Tokai requested the TCEQ change §112.112(c) to allow a weighted average of the number of furnaces used during each hour of production rather than the minimum number to calculate the allowable emission limit for that hour. The proposed requirement to use the minimum number of furnaces is impossible to comply with under some operating scenarios. Difficulties would arise during unit start-ups and shutdowns, and during other transitional periods as well. The rule requires performing unit start-ups and shutdowns instantaneously, at precisely the top of the hour to remain compliant. Tokai provided an equation for calculating emissions based on the number of furnaces operating in each minute of an hour that would be summed to give the hour's emission limit.

Response

The TCEQ understands that the use of the fewest number of furnaces on-line during the transitional hours may be impossible to comply with during certain circumstances. As a result, the TCEQ adopted the time weighted average as a reasonable way to determine the appropriate emission limits during infrequent (3.5% of the time) transitional periods. The TCEQ modeled 192 scenarios that bookend the possible range of emission limits when various combination of furnaces could be on-line. TCEQ's modeling showed attainment of the NAAQS under all 192 scenarios.

Comment

Tokai requested TCEQ delete §112.112(g) which prohibits operation of the three existing flares following the rule compliance date and which would apply even if the equipment in question did not combust tail gas and had no SO_2 emissions. Tokai stated that although it does not foresee a need to operate the existing flares following the compliance date, the TCEQ exceeds its authority by requiring actual cessation of operation, rather than simply prohibiting the combustion of tail gas in the referenced equipment, as it has already done in proposed §112.112(e).

Response

Tokai represented that there would be no SO_2 emissions from these sources in the modeling; consequently, the rule cannot allow SO_2 emissions from these sources. However, to provide the most flexibility possible, the TCEQ changed the language to prohibit the routing of sulfur or sulfur containing compounds to the EPNs rather than prohibit their operations.

Comment

The EPA commented §112.112(h) indicates EPN Flare 4 must be constructed at the specific location as modeled and have a stack height of at least 60.35 meters. If a flare taller than 60.35 meters is constructed, the modeling will have to be redone prior to construction as dispersion parameters will change and overlap of sources may generate different concentration fields and maximum modeled DVs.

Response

The rule is changed to state that the stack height for EPN Flare 4 must be 60.35

meters as modeled in the attainment demonstration.

Comment

The EPA commented §112.112(i) states EPN 13A must have stack height of no less than 65.00 meters. This provision should be changed to "EPN 13A must have a stack height of 65.00 meters". As written, a stack height greater than 65.00 meters could be installed that would be in violation of Good Engineering Practice (GEP) rules. Any height above 65.00 meters must be approved by TCEQ and EPA in accordance with GEP rules. If a stack taller than 65 meters is approved, the modeling will have to be redone prior to construction as dispersion parameters will change, and the overlap of sources may generate different concentration fields.

Response

The stack height requirement in §112.112(i) is changed to be 65.00 meters.

§112.113

Comment

The EPA commented that §112.113 includes requirements to monitor the volume of tail gas that is routed to the incinerator or flare and to the dryers using continuous monitoring for each gas stream and to continually determine the split of the tail gas that is routed to the dryers and to the incinerator or flare. Emission estimates in the current modeling are based on a split of 70% of the tail gas going to either the incinerator or flare and the other 30% routed to the dryers. Hourly calculations will be generated and should be compared to this 70/30 split. If these hourly calculations differ by more than 5%, that would result in significantly different emissions from the individual sources at Tokai and would require additional modeling to verify that modeling still demonstrates attainment based on a different split of tail gas and emission rates. Alternatively, the 70/30 could be included as a specific a limit in this section.

Response

The model was not based on an assumed 70/30 split but instead on the emission limits in the rule. In response to this comment the emission calculations were corrected to use the actual split of tail gas from each production unit rather than assume that the split is equal across all units.

Comment

The EPA commented that §112.113 should also include continuous measurement of total sulfur in tail gas stream on a continuous basis to the incinerator or flare if accurate measurements can be collected. Using total sulfur monitoring data and the volume tail gas monitoring through both the incinerator or flare and through the dryers, hourly emissions for each stack or flare could be explicitly calculated instead of sampling feedstocks and finished products periodically and determining a mass balance that would not be as protective of the one-hour SO_2 NAAQS. Feedstock sampling and finished product sampling could be completed when the tail gas volume monitors or the total sulfur sampling are not operating. Additional recordkeeping and reporting requirements would need to be included in §112.113, including a formula for SO_2 emissions calculation for hourly emissions from the incinerator & HRSG, dryers, and flare(s).

Response

The TCEQ evaluated the use of continuous sulfur analyzers; however, they were determined to be cost prohibitive and potentially difficult to maintain. Tokai estimates that continuous total sulfur analyzers required to determine hourly emissions from each EPN would cost approximately $1.3 million for both carbon black sites addressed in this rulemaking. However, additional sampling of carbon black oil was included in the rule to improve the accuracy of the mass balance approach. Additional emission calculations for each EPN were also added to §112.113 for clarity. Stack testing once every five years was also added to the provisions to provide additional information regarding compliance.

Comment

The EPA commented that for §112.113(b) EPN 13A is listed twice and that one should be EPN 12A. The EPA commented that in Figure 30 TAC §112.113(b) the citations of §112.112(4)(E) and (F) should likely cite to §112.113(e)(5) and (6).

Response

The inadvertent typographical error for EPN 12A is corrected at adoption. The citations in Figure 30 TAC §112.113(b) are corrected at adoption.

Comment

The EPA commented that §112.113(e)(2) requires measuring the flow of tail gas to each dryer but §112.113(e)(3) requires the measurement for all dryers, that the applicability of the provisions should be clarified, and that the applicable dryers should be listed as affected units.

Response

The TCEQ deleted the redundancy and clarified the requirements for measuring flow from each production, as needed for the mass balance emission calculations.

Comment

The EPA commented that §112.113(g) requires daily measurement of the sulfur content of carbon black oil feedstock, but it is not clear that if more than one feedstock is used with differing sulfur contents, whether each would be monitored. Please clarify if more than one feedstock is used and how multiple feedstocks would be handled and monitored.

Response

Feedstock from different sources is sent to a single mix tank where it is mixed before being fed to production units. Sampling from this mix tank will minimize any differences in feedstock from different sources. In the adopted rule, sampling of the feedstock was increased from once per day as proposed to twice per day to minimize the impact of any differences in sulfur concentration in feedstock over time.

§112.115

Comment

Tokai stated concerns about provisions in §112.115(e) that vaguely refer to approval by EPA, without clearly stating how such an approval process is to take place. Tokai is not aware of any streamlined process for EPA approval of an alternative to test methods specified in a SIP, other than an actual SIP revision. If such a streamlined process exists, TCEQ should explain what it is. Otherwise, TCEQ should revise the provisions such that they only refer to minor modifications to test methods or monitoring methods which States are routinely given authority by EPA to grant.

Response

The TCEQ agrees that minor modifications to monitoring methods or test methods should be allowed without rulemaking and a SIP revision. The TCEQ notes that a provision allowing this was approved by the EPA as a SIP revision under 30 TAC 115.725(m). As a result, TCEQ is adopting language consistent with 30 TAC Chapter 115 to allow minor modifications to test methods or monitoring methods if approved by the executive director. In addition, language was added to clarify that increases in the frequency of monitoring and replacement of parametric monitoring with direct emissions monitoring can be approved under this provision.

§112.117

Comment

Tokai recommended TCEQ delete §112.117(c), which requires conducting a "full system audit" as a contingency measure if the EPA determines the Howard County SO_2 nonattainment area fails to achieve attainment, and instead refer to TCEQ's existing enforcement policies. Tokai stated that TCEQ's FSA provision suggests that TCEQ will limit its enforcement of the NAAQS to the required reporting scheme, which may be contrary to what EPA envisioned in issuing its guidance and that the FSA provisions require Tokai to identify exceptional events under 40 CFR §50.14, but these demonstrations are the responsibility of a State, federal land manager, or other federal agency, not a regulated entity. Tokai also stated that TCEQ's FSA provision implies that the EPA only issues findings of failure to attain when actual air quality does not meet the NAAQS, which is at odds with how the EPA handled recent determinations. Tokai gave as an example, the EPA finding for St. Bernard Parish, LA, which was based on its review of Title V deviation reports, despite the presence of valid monitoring data consistent with a finding of attainment. Tokai further commented that if a similar outcome occurred for Howard County, a systems audit focused on local meteorology and monitoring data would *not* generate any useful data.

Response

The commission proposed the full system audits throughout the rules to receive information from each site within a nonattainment area, after a finding of failure to attain, on the conditions at each site that may have contributed to the finding. The commission notes that the audits are triggered by notices from the TCEQ, not from the finding of failure to attain itself. If it is clear from available information (ambient monitoring, modeling, compliance reports, etc.) that a site was not responsible for a failure to attain, the TCEQ would not require a full system audit of that site. However, because it may not be clear which site(s) contributed to the EPA's finding, under some circumstances the commission may require the audits for all sites in the nonattainment area. At adoption, the wording is changed so that the sites are not required to identify an exceptional event but rather any emissions

event(s) and the conditions that existed at their site during the relevant period. The commission recognizes that an EPA finding of failure to attain could be based on Title V deviation reports as well as other information but also that the information from the audits may be important for determining if other conditions within the nonattainment area with a potential to affect conditions leading to the EPA's finding were occurring at the same time.

§112.118

Comment

The EPA stated it is unclear when the control requirements of §112.118 would require installation of controls or other reductions and modifications. The EPA stated that the language indicates the owner or operator must comply with the requirements "as expeditiously as practicable, but no later than January 1, 2025." The EPA also commented that there is no discussion of how soon Tokai can comply with the new emission limits nor a discussion and rational of why several years are necessary to achieve compliance with the emission limits. The EPA further stated it is important to get the reductions in place as expeditiously as practicable in order to achieve attainment because the monitored DV that will be part of the basis of determining attainment or nonattainment is based on three consecutive years of data. EPA noted that other areas which require longer times for compliance provide dates and RFP achievements as a demonstration that they are satisfying the "as expeditiously as practicable" requirement.

Response

In response to this comment, the TCEQ reevaluated the compliance dates to ensure that compliance is achieved as soon as practicable, depending on site specific constraints. Upon the effective date of the rule there will be shortly over two years before the proposed compliance date. Tokai is designing and constructing a new stack for the incinerator and a new flare and expressed concern that the schedule may be impacted by global supply chain issues. As a result, they have indicated that they cannot comply until January 1, 2025. Because the soonest practicable date for compliance is January 1, 2025, the term "as soon as practicable" was removed from the provisions at adoption.

<u>Subchapter F Division 1</u> (CP Chem)

Comment

The EPA commented that rule sections on testing requirements and approved test methods are missing and needed to clarify what the testing requirements and approved test methods are for Division 1.

Response

The only affected sources at the CP Chem site are two flares and fugitive sources, neither of which have stacks that allow for performance testing in the way that

other sources do. In addition, a mass balance approach to determining emissions is not used for this source which means that test methods for sampling are not needed. The monitors used by CP Chem for their flares detect both H_2S and organic sulfur. There are only very minor amounts of SO_2 in the flared gases to the South Flare (none to North Flare), which CP Chem accounts for by adding 0.015 lb/hr SO_2 to each hourly calculation of SO_2 emissions for the South Flare. The fugitive emission calculations are based on testing already done by CP Chem with no additional testing needed. Therefore, testing requirements and approved test methods are not needed for CP Chem.

§112.202

Comment

The EPA commented that individual flare limits modeled should be included in §112.202 along with the cap for both flares.

Response

The commission tested different scenarios of the cap including scenarios where the maximum cap limit was assigned to each individual flare. All cap scenarios tested demonstrated attainment of the NAAQS. Therefore, it is concluded that the cap emission limit is protective of the NAAQS and individual flare limits are not required. No change was made to the rule in response to this comment.

§112.203

Comment

The EPA commented for §112.203 that monitoring the temperature in the trailers used to store sulfolene does not account for SO_2 emissions from the sulfolene building and that there is no calculation method to determine SO_2 emissions from the trailers based on the measured temperatures. The EPA recommended providing an analysis and data of how the specific temperature threshold is calculated, in addition to documenting how that temperature threshold was used to calculate emissions.

Response

In response to this comment the TCEQ added equations for the calculation of SO_2 fugitive emissions from the trailers and building. Because there is no clearly established method for determining SO_2 fugitive emissions, the TCEQ relied on a site-specific study to determine the decomposition rate of sulfolene to SO_2 and butadiene. Hourly fugitive emissions will be calculated by multiplying the decomposition factor by the weight of the sulfolene stored. The decomposition rate is determined by an empirical equation using the amount of time the sulfolene is stored, the temperature at which it is stored, and the amount stored in the sulfolene handling building and in each trailer.

Comment

CP Chem provided alternate language for §112.203(b): "Monitor the sulfur content of gases routed to EPN FL-1 (North Flare) and to EPN FL-2 (South Flare) by using separate analyzer, which are capable of measuring and recording total sulfur compounds levels on a continuous basis with an accuracy of ±2.5% of full scale for >50 parts per million concentrations".

Response

In response, the rule was changed to incorporate the accuracy language from CP Chem in place of the detection limit that was proposed. CP Chem indicated that there sometimes are low amounts of SO_2 in the gases sent to the flare but that their monitor does not detect SO_2. To account for the SO_2 present prior to flaring, CP Chem committed to adding 0.015 pound per hour of SO_2 to each hourly calculation of SO_2 emissions from the South Flare.

Comment

CP Chem stated that the monitoring and recordkeeping requirements in §112.203 and §112.204 should be based on a "block one-hour average" and requested that the TCEQ make that change.

Response

The temperature in the sulfolene trailers is required to be measured on an hourly basis, and continuous monitoring is required for gases routed to the flares. Continuous monitoring averaging times are already defined, and a one block average is not necessary when emissions are monitored once per hour. As a result, the commission does not consider a block one-hour average to be appropriate for either. No change was made to §112.203 in response to this comment.

§112.206

Comment

CP Chem commented that the proposal preamble discussion for §112.206 is incorrect for the number of storage trailers at each of the sulfolene holding areas is incorrect. There are two trailers at the sulfolene building and six at the parking area.

Response

The preamble discussion was corrected on the numbers of trailers. No change was made to the rule in response to this comment.

§112.207

Comment

CP Chem commented that the requirement for submitting reports in §112.207(a) and (b) conflict, with (a) only requiring exceedance reports in the year after an exceedance occurred while (b) requires the same exceedance report with additional information on exceedances of temperatures in the sulfolene storage trailers every year. CP Chem commented that an exceedance of the highest temperature at which they tested the decomposition of sulfolene does not mean that there was an exceedance of the emission limit for the sulfolene storage areas. CP Chem requested that the rule require an exceedance report of the excess temperature only if there is an exceedance of the emission limit as well.

Response

Proposed §112.207(b) is removed at adoption based on changes for the monitoring of the fugitive emissions from sulfolene decomposition. CP Chem updated the study used to determine decomposition to ensure the temperature range it covers is adequate. In addition, the TCEQ added equations for calculating emission rates and removed the limit on the temperature of the trailers because the temperatures will be taken into account in the emission calculations and reports will be required based on exceedance of emission limits rather than exceedance of temperature. CP Chem will only need to file a report under §112.207(a) if there is an exceedance of an emission limit provided in §112.202.

§112.208

Comment

The EPA commented for §112.208 that it is not clear what schedule is intended for the installation of controls or making reductions and modifications and that a detailed analysis of what is needed to meet each requirement and what constitutes "as expeditiously as practicable" for each requirement.

Response

In response to this comment, the TCEQ reevaluated the compliance dates to ensure that compliance is achieved as soon as practicable, depending on site specific constraints. Upon the effective date of the rule there will be shortly over two years before the proposed compliance date. CP Chem expressed concern over the impact global supply chain issues may have on their ability to procure a monitor and as well as the amount of time it will take them to identify an appropriate monitor for this particular gas stream. CP Chem also pointed out that it will need to install temperature monitors and design new monitoring procedures. As a result, CP Chem has indicated that they cannot comply until January 1, 2025. Because the soonest practicable date for compliance is January 1, 2025, the term "as soon as practicable" was removed from the provisions at adoption.

<u>Subchapter F Division 2 </u>(IACX)

Comment

The EPA commented that rule sections on testing requirements and approved test methods are needed to clarify what testing using which methods are needed for Division 2.

Response

Because changes to the monitoring methods in §112.213 at adoption require on-going testing, testing requirements and approved test methods are added as §112.213(b) and (c), respectively.

§112.213

Comment

The EPA commented that the analyzer in §112.213(1) should be able to measure all sulfur compounds that might be present in sour gas instead of only H_2S.

Response

In response to this comment, the monitoring requirements in §112.213(1) are changed to provide IACX the options of monitoring the total sulfur content of the flared gases consistent with 40 CFR §60.107a(e)(1) or monitoring H_2S and using it as a surrogate for total sulfur consistent with 40 CFR §60.107a(e)(2).

§112.218

Comment

As in §112.208, the EPA commented for §112.218 that it is not clear what schedule is intended for the installation of controls or making reductions and modifications and that a detailed analysis of what is needed to meet each requirement and what constitutes "as expeditiously as practicable" for each requirement. The EPA commented further that since IACX is only lowering allowable emission rates without installing controls or changing stack parameters, it seems the site could comply within 6 months to a year. Achieving reductions as quickly as possible is important because the design value is based on emissions over three years.

Response

In response to this comment, the TCEQ reevaluated the compliance dates to ensure that compliance is achieved as soon as practicable, depending on site specific constraints. IACX Rock Creek Gas Plant committed to a compliance date of October 1, 2023, and the rule was updated accordingly. Because the soonest practicable date for compliance is identified in the rule, the term "as soon as practicable" was removed from the provisions at adoption.

Subchapter F Division 3 (Orion)

§112.222

Comment

The EPA commented that the language in §112.222(c) should be reworded to say that tail gas can only be routed to and combusted in the Waste Heat Boiler or Combined Flare rather than combusted in a source whose emissions are routed to the boiler's stack or the flare.

Response

The comment does not reflect how the production units operate. Tail gas is burned in the carbon black dryers as well as the Waste Heat Boiler or flare. Rather than venting to the atmosphere, emissions from the dryers are routed to the boiler or flare (used only when the boiler is not operating) and are thereby routed to (and exhausted from) EPN E-6BN or the flare (to become EPN CFL) as stated in the proposed rule. Making the change requested would prohibit the dryers from burning tail gas, requiring a switch to natural gas and resulting in a slight increase in the SO_2 emissions from the site. No change to the rules was made in response to this comment.

§112.223

Comment

The EPA commented that the use of periodic sampling and a mass balance calculation in §112.223 is not protective of the NAAQS and that the total sulfur content and flow rate of the tail gas stream to the flare should be continuously monitored, with the sampling and mass balance calculation used only when the continuous monitor or flow monitor is not operating.

Response

Orion doesn't typically use the flare and is restricted by their consent decree with the EPA to using it 168 hours per year on an annual basis and 720 hours during flaring events that are limited to occurring once every five years. Orion's only other EPN is monitored with a CEMS. Considering that the flare is only used as a backup, the only other EPN has a CEMS, the cost analysis provided for the other carbon black sites, as well as the ongoing concerns regarding reliability of analyzers for these types of streams, the TCEQ determined that continuous total sulfur analyzers are not economically reasonable in this case. However additional sampling of the carbon black oil was included in the rule to minimize the impact of any variations in sulfur content on emission calculations when the boiler is down and the flare is used.

Comment

The EPA commented that for the daily measurement of the sulfur content of the feedstock it is not clear that each feedstock would be monitored if there is more than one.

Response

Because the flare is infrequently used, variations in sulfur content of feedstock will not typically impact the determination of emission rates. In addition, all feedstock is mixed in a mix tank before being fed to the reactors, and samples are taken from the mix tank which minimizes the impact of any differences in sulfur content in feedstocks from different sources. In addition, the frequency of monitoring the carbon black oil is increased from once per day to twice per day to minimize the impact of changes in the sulfur content of the carbon black oil over time.

§112.228

Comment

As for §112.208, the EPA commented for §112.228 that it is not clear what schedule is intended for the installation of controls or making reductions and modifications and that a detailed analysis of what is needed to meet each requirement and what constitutes "as expeditiously as practicable" for each requirement.

Response

In response to this comment, the TCEQ reevaluated the compliance dates to ensure

that compliance is achieved as soon as practicable, depending on site specific constraints. Orion Borger Carbon Black Plant committee to a compliance date of June 30, 2023, except for those requirements that relate to the construction of a new flare and the rule was updated accordingly. Because the soonest practicable dates for compliance are identified in the rule, the term "as soon as practicable" was removed from the provisions at adoption.

Subchapter F Division 4 (P66)

General

Comment

Phillips 66 stated that it is a major employer in Hutchinson County but is only marginally competitive in the fuels marketplace. Phillips 66 commented that the proposed rules impair their ability to adapt and improve competitiveness, jeopardizing the future of the refinery, and that other refineries in the area do not have the same restrictions and can therefore make modifications easier at a lower cost. Phillips 66 stated that the refinery and its employees share the goal of improving air quality for the community and that everything it requests still supports that goal.

Response

The TCEQ provided additional flexibility through the AMOC provisions added as adopted §112.232(k).

§112.230

Comment

Phillips 66 requested that TCEQ delete the last sentence of §112.230(a): "Once approved by the United States Environmental Protection Agency (EPA), the requirements in these rules continue to apply until the EPA approves their removal." EPA actions on SIP submittals and TCEQ rulemaking are completely separate processes. The TCEQ can enforce rules before they become part of the SIP but cannot enforce after they are repealed.

Response

The commission disagrees with the commenter's assertion that the agency will enforce rules that are repealed; however, to avoid confusion this language has been removed at adoption. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

§112.232

Comment

Phillips 66 commented that the approach to emission limits for FCCUs at the Borger Refinery is completely different than what is proposed for the Alon USA Refinery, which has a seven-day rolling average proposed with no limits on stack flow. The difference is based on Alon's supplying four years of CEMS data to demonstrate the discount factor is appropriate. However, the TCEQ does not explain why a different approach was taken, and Phillips 66 is concerned that the difference is arbitrary and may put the Borger Refinery at a competitive disadvantage and that the TCEQ did not consider social and economic factors in setting their FCCUs' emission limits. With respect to the restrictions on stack flow, Phillips 66 stated that because stack flow necessarily changes from zero to non-zero values during startups and to zero in shutdowns and because turndown rates are needed for operations, it is not possible to comply with the limits at all times. Phillips 66 commented that a seven-day rolling average should be provided for the Borger Refinery FCCUs. Phillips 66 stated that the data relevant to the discount factor was provided with the comments and that because differing FCC loads were not modeled for Alon, the 100% load-case CEV of 155.49 lb/hr should be used for the Borger Refinery FCCUs, which with the discount factors of 0.749 for FCC P29 and 0.780 for FCC P40 yield emission factors of 116.47 lb/hr and 121.25 lb/hr, respectively. Phillips 66 requested that the rules be changed to include these seven-day rolling average emission factors in place of those on a one-hour basis, remove the emission limits based on varying load, and remove the stack flow restrictions.

Response

The TCEQ has evaluated the historical data provided by Phillips 66 and determined that a longer averaging time is supported based on variability and the likelihood that exceedances of the CEV will be rare. Before adopting the one hour averaging period for these sources the one-hour CEV was lowered significantly from the maximum hourly rate in the proposed rule of 155.49 lb/hr. The longer averaging time is appropriate because there is high degree of variability in the historic emissions data and exceedances of the CEV are expected to be rare. In addition, the variable load limits have been removed as have the restrictions on stack flow. Because P66 agreed to a new lower emission rate of 130 lb/hr emission rate for the two FCCU units under all operating conditions. The TCEQ modeled the new emission rates for various operating scenarios including the 50% and 75% operating load scenarios with lower stack velocity. All scenarios showed attainment with the lower emission rate thereby negating the need for stack flow restrictions.

Comment

Phillips 66 commented that §112.232(e) should be deleted or changed to only apply to normal operating conditions or that the TCEQ should explain its reasoning for the provision. Phillips requested that if the TCEQ intended that the requirement apply at all times, even though EPA determined it should not, the TCEQ should also provide an analysis of the economic and social consequences of the requirement, including its assessment of technical feasibility.

Response

The TCEQ understands that it may not be technically feasible to comply with the sulfur content requirement during MSS and compliance with that limit during MSS is not required to meet the MSS emission limits established in the rule. As a result, the rule is clarified that the limit applies except as provided for in 40 CFR §60.103a(h).

§112.233

Comment

Phillips 66 commented that the proposal preamble discussion for §112.233 implies that the TCEQ believes the FCCUs at the Borger Refinery are all subject to 40 CFR Part 60, Subpart Ja, but these sources are subject to Subpart J instead. In addition, Phillips 66 proposed that §112.233(a) be revised as follows: "Install, operate calibrate and maintain a CEMS to measure and record the SO_2 emissions from EPN 29P1 and EPN 40P1 in accordance with the procedures specified at 40 CFR §60.105a(g) for FCCUs and FCUs subject to an SO_2 limit under NSPS Ja (regardless of whether EPN 29P1 and EPN 40P1 are "affected facilities" for purposes of NSPS Ja.

Response

TCEQ incorporated at adoption Phillips 66 comments into minor §112.233(a) revisions to definitively identify the specific portions of 40 CFR §60.105a(g) procedures (40 CFR §60.105a(g)(1), (2), and (5)) that apply to EPN 29P1 and EPN 40P1 monitoring requirements. These minor revisions were adopted to clarify the proposed rule requirements.

Comment

Phillips 66 requested that the phrase “and the exhaust gas flow rates” be removed from §112.233(a) because 40 CFR Part 60 Subpart Ja does not require stack flow monitoring and that the clause “regardless of whether EPN 29P1 and EPN 40P1 are "affected facilities" for purposes of NSPS Ja)” be added because the FCCUs are not currently subject to Subpart Ja.

Response

Subpart Ja does not require flow monitoring because the emission standards are on a concentration rather than on a pounds-per-hour basis. Exhaust gas flow rates are required for demonstrating compliance with the emission limits in these rules; therefore, the requirement to monitor flow is not removed from the rule. However, the phrase “regardless of whether these provisions otherwise apply or provide exemptions for certain activities” is added in response to this comment.

Comment

Phillips 66 commented that the proposal preamble discussion for §112.233 implies that the TCEQ believes the SRUs at the Borger Refinery are all subject to 40 CFR Part 60, Subpart Ja, but this is incorrect and these units are subject to Subpart J instead. Since Subpart J does require the SRUs to install a CEMS, Phillips 66 proposed that §112.233(b) be revised as follows: Install, operate calibrate and maintain a CEMS to record hourly SO_2 emissions from EPN 34I1 and EPN 43I1 in accordance with the procedures specified at 40 CFR §60.105(a)(5).

Response

TCEQ proposed rules contain the most detailed, current and complete SRU monitoring requirements codified under 40 CFR Part 60, Subpart Ja to accurately verify compliance with the Hutchinson County modeled emission limits in the attainment demonstration. In staff's opinion, it would not be appropriate or consistent with the monitoring requirements for other similar sources in the proposed rule to specify less detailed, current or complete SRU monitoring requirements for EPN 34I1 and EPN 43I1. Therefore, no changes were made in response to this comment.

Comment

For the flares covered in §112.233(c), Phillips 66 stated that EPNs 66FL1, 66FL2, 66FL3, and 66FL12 are subject to 40 CFR Part 60, Subpart Ja while EPN 66FL13 is subject to Subpart J and primarily combusts gases from upsets. Because Subpart J does not require sulfur monitoring for EPN 66FL13 but the flare is equipped with a flow meter, process knowledge and flow data are used to determine hourly emissions. Because process vent gas from upsets in two specific units are infrequently burned in EPN 66FL13, Phillips 66 stated that they can develop representative samples of the flare gas from the units and that a one-time representative measurement using an approved test method would be appropriate. Phillips 66 requested that §112.233(c) be changed to require continuous flow rate and sulfur content monitoring under Subpart Ja for EPNs 66FL1, 66FL2, 66FL3, and 66FL12, continuous flow rate monitoring under Subpart Ja for EPN 66FL13 (with a parenthetical clause that it must comply as if it were subject), and determination using either or both an approved test method or Subpart Ja continuous monitoring for sulfur content for the two flare gas streams.

Response

Because the rule must have monitoring requirements sufficient to demonstrate compliance with the emission limits in the rule, Phillip 66 proposed that they submit a permit alteration to reduce the EPN 66FL13 potential-to-emit (PTE) below the 7.8 ug/m^3 significant impact level. TCEQ staff have reviewed the application and verified that the authorized PTE reduction qualifies EPN 66FL13 as an insignificant emission source. Therefore, EPN 66FL13 is removed from the §112.233(c) and the emission CAPs that included EPN 66FL13 have been lowered by EPN 66FL13's contribution to the caps at adoption. In addition, monitoring

requirements associated EPN 66FL13 have been removed at adoption.

Comment

Phillips 66 commented that for the facilities covered by §112.233(d) the provision therein is not clear that testing can be done at a point separate from the inlet of each facility and that 40 CFR Part 60, Subparts J and Ja only require monitoring the concentration of H_2S, not total sulfur. Phillips 66 requested that §112.233(d) be changed to require continuous monitoring of fuel consumption and H_2S concentration by volume and either monthly testing with an option for quarterly testing if three consecutive samples indicate 90% or greater of the total sulfur is H_2S or continuous monitoring for total sulfur content.

Response

In 40 CFR §60.107a(a)(2)(iv), the federal rules cited are clear that monitoring can be at a point other than at the inlet to a combustion facility for facilities using the same source of fuel gas. For facilities using different fuel gases, the commission is not placing any monitoring location restrictions other than what is in the federal rules cited. Because continuous flow rate and H_2S concentration are monitored under this approach and any additional sulfur in the fuel case is accounted for and verified by monthly or quarterly sampling with an approved test method the TCEQ has made changes at adoption consistent with this comment and included

equations for converting the H_2S concentration to pounds per hour of SO_2.

§112.235

Comment

Phillips 66 requested that ASTM Method D-6667 (Determination of Total Volatile Sulfur in Gaseous Hydrocarbons) be added as an approved test method in §112.235(d).

Response

The TCEQ evaluated Phillips 66's request and added ASTM D-6667 (Determination of Total Volatile Sulfur in Gaseous Hydrocarbons) as an approved test method under proposed §112.235(a).

Comment

Phillips 66 commented that §112.235(e) should be clarified on the process for EPA approval of alternate test methods because the EPA does not have a streamline process for approvals, only the full SIP revision process. Therefore, §112.235(e) should be changed to the language in the first three sentences of §1152.725(m).

Response

The TCEQ agrees that minor modifications to monitoring methods or test methods

should be allowed without rulemaking and a SIP revision. The TCEQ notes that a provision allowing this was approved by the EPA as a SIP revision under 30 TAC 115.725(m). As a result, the TCEQ adopted language consistent with 30 TAC Chapter 115 to allow minor modifications to test methods or monitoring methods if approved by the executive director. In addition, language was added to clarify that increases in the frequency of monitoring and replacement of parametric monitoring with direct emissions monitoring can be approved under this provision.

§112.237

Comment

Phillips 66 requested that the phrase "or fails to meet a required stack parameter" be removed from §112.237(a) and that the phrase "or failure to meet a required stack parameter" be removed from §112.237(a)(1), (2), and (3).

Response

Because dispersion characteristics at allowed emission limits are critical to the attainment demonstration modeling and are directly related to the stack characteristics (exhaust flow rate and temperature and stack height), the requirements for stack parameters in the rules are requirements whose noncompliance needs to be documented in reports to the TCEQ. Even though there are currently no stack parameter requirements in the rule for this site, the language

that accommodates them in the recordkeeping section needs to remain in place because the AMOC could generate the need to establish stack parameters. No change to the rules was made in response to this comment.

Comment

Phillips 66 commented that the requirement for a full system audit should be removed from §112.237(c) because it is arbitrary and unreasonable for the executive director to require the audits without have first made a culpability determination based on excess emissions since it should be easy to identify the source causing a finding of failure to attain because the sites are in close proximity Phillips 66 stated that the audit would be an economic burden for the refinery and would not serve the purpose of the contingency measures. Phillips 66 suggested that instead, the contingency measures should be a description of TCEQ's existing enforcement program, as provided in the EPA's 2014 guidance. Phillips 66 stated that the audits might be seen as self-policing by the sites, and it is the responsibility of the state, a federal land manager, or a federal agency to make an exceptional event demonstration. Further, Phillips 66 commented that the EPA can make a finding of failure to attain on based on modeling or Title V deviation reports, so the FSAs could be of questionable value. Phillips 66 also commented that contingency measures should focus only on the identified source. In their oral comments, Phillips 66 stated that performing a full system audit when a failure to attain is caused by another company's emissions events does not seem practical.

Response

The commission proposed the full system audits throughout the rules to receive full information from each site within a nonattainment area after a finding of failure to attain on the conditions at each site that may have contributed to the finding. The commission notes that the rule language triggers the audits from the TCEQ notifying sites of the EPA's finding of failure to attain, not from that finding itself. If it is clear which site(s) caused an exceedance, deviation report, or other factor leading to the EPA's finding, the commission does not intend to trigger the contingency measure for other sites. However, because it may not be clear which site(s) contributed to a monitor exceedance or other factors leading to the EPA's finding, under some circumstances the commission may trigger the audits for all sites in the nonattainment area. At adoption, the wording is changed so that the audits do not require a site to identify an exceptional event but rather any emissions event(s) and the conditions that existed at their site during the relevant period. The commission recognizes that an EPA finding of failure to attain could be based on Title V deviation reports as well as other information but also that the information from the audits may be important for determining if other conditions within the nonattainment area with a potential to affect conditions leading to the EPA's finding were occurring at the same time.

§112.238

Comment

As in §112.208, the EPA commented for §112.238 that it is not clear what schedule is intended for the installation of controls or making reductions and modifications and that a detailed analysis of what is needed to meet each requirement and what constitutes "as expeditiously as practicable" for each requirement.

Response

The TCEQ has evaluated the compliance dates to ensure that compliance is achieved as soon as practicable and compliance dates depend on site specific constraints. At the time the rule is finalized, there will be just over two years before the proposed January 1, 2025 compliance date. Phillips 66 has indicated that they will need to make physical modifications to the refinery flare gas stream which will be scheduled during a turnaround. Turnarounds are scheduled by companies to align with contractor schedules, potential multiple maintenance projects that require coordination, and other relevant issues such as energy demands, weather, etc. The refinery will also have to develop new procedures for complying with monitoring quality assurance requirements and emission limits not currently specified in a permit. Therefore, the refinery cannot commit to compliance before January 1, 2025. Because the soonest practicable date for compliance is January 1, 2025, the term "as soon as practicable" was removed from the provisions at adoption.

Subchapter F Division 5 (Tokai)

§112.240

Comment

Tokai requested the TCEQ delete §112.240(a) and other provisions elsewhere in the rules that require EPA approval. TCEQ does not have authority to promulgate rules that allow TCEQ to enforce after rules are repealed or that require EPA approval to repeal.

Response

The commission disagrees with the commenter's assertion that the agency will enforce rules that are repealed; however, to avoid confusion this language has been removed at adoption. This change does not affect when the rules may no longer apply because their removal from the SIP must be approved by the EPA. The rules are enforceable by the TCEQ alone until the EPA approves and incorporates the rules into the SIP. If the TCEQ removes provisions from the rule, those provisions stop being enforceable by the TCEQ on the effective date of the rule change but remain enforceable by the EPA until they approve the SIP revision for the removal.

§112.242

Comment

The EPA commented that the language in §112.242(e) should be reworded to say that tail gas can only be routed to and combusted in EPNs 119, 121, 122, Flare-1 or New Flare rather than combusted in a source whose emissions are routed to one or more of those EPNs.

Response

The comment does not reflect how the production units operate. Tail gas is burned in the carbon black dryers as well EPNs 119, 121, 122, Flare-1 or New Flare. Making the change requested would prohibit the dryers from burning tail gas, requiring a switch to natural gas and resulting in a slight increase in the SO_2 emissions from the site. No change to the rules was made in response to this comment.

Comment

Tokai requested the TCEQ delete §112.242(f)–(h) which prohibit operation of existing flares and dryer purge stacks following the compliance date and would apply even if the equipment in question did not combust tail gas and have no SO_2 emissions. Although Tokai does not foresee a need to operate the existing flares (except, perhaps, Flare-1) and dryer purge stacks following the compliance date, they stated that TCEQ exceeds its authority by requiring actual cessation of operation, rather than simply prohibiting the combustion of tail gas in the referenced equipment, as it has already done in proposed §112.242(e).

Response

Tokai represented that there would be no SO_2 emissions from these sources in the modeling; consequently, the rule cannot allow SO_2 emissions from these sources. However, to provide the most flexibility possible the TCEQ changed the language to prohibit the routing of sulfur or sulfur containing compounds to the EPNs rather than prohibit their operations.

Comment

The EPA commented that §112.242(i)(2) and (j) should be reworded by changing "may be" to "may only be".

Response

The proposed language in §112.242(i)(2) states that "tail gas may be routed to EPN New Flare (New Flare) only when Boilers 1 and 2 are not operating." The TCEQ believes adding an additional "only" could create confusion and is not necessary to limit use of flares to only those periods when neither boiler is operating. Instead, the language was clarified to state that tail gas may be routed to the flares only when neither Boiler 1 nor Boiler 2 is operating.

§112.243

Comment

The EPA noted that in §112.243 continuous monitoring of the volume of the tail gas stream to each combustion device and that emission estimates in current modeling are based on a 70/30 split of tail gas going to either the boilers (or flare) or to the dryers. EPA commented that the required hourly calculations should be compared to the presumed split and if they differ by more than 5%, additional modeling would be needed to demonstrate attainment. EPA further commented that §112.243 should require continuous monitoring of the total sulfur content of the tail gas if accurate measurements are possible and that use of this data and continuous monitoring of the volume of tail gas to the flare would provide monitoring that is more protective of the NAAQS than the current mass balance approach, which should be used only when the continuous monitor or flow monitor is not operating.

Response

The modeling was not based on an assumed 30/70 split but instead on the emission limits in the rule. In response to this comment the emission calculations were corrected to use the actual split of tail gas from each production unit rather than assume that the split is equal across all units.

Comment

The EPA commented that there is a typographic error that must be corrected in §112.243(h) in that it refers to a paragraph 10 that does not exist in the subsection. The EPA further commented that §112.242(h) is not clear on the method for calculating emissions from the New Flare and should be rewritten to include an equation for the calculation, including the ratios in the subsection.

Response

The commission is unable to find any reference to "paragraph 10" in proposed §112.243(h). The only citation therein is to "subsection (j) of this section," which contains the equation for the calculation. As required by §112.243(d), Tokai must have a totalizing tail gas flow meter for each combustion device burning tail gas that continuously measures the tail gas volumetric flow. The ratios in §112.243(h) are the ratios of the volumetric flow from a production unit to an EPN divided by the total volumetric flow rate from the production unit. Equations for calculating emissions from each EPN were provided to improve clarity.

Comment

The EPA commented for §112.243(j) requires that emissions must be calculated or determined on a one-hour block basis but that because of variability in the sampling and measuring frequency, it is not clear that the test methods and measurements can translate into a block one-hour period standard. The EPA stated that sampling and measurements of greater than one-hour periods would not result in an accurate one-hour calculated emission measurement.

Response

The TCEQ evaluated the use of continuous sulfur analyzers; however, they were determined to be cost prohibitive and potentially difficult to maintain. Tokai estimates that continuous total sulfur analyzers required to determine hourly emissions from each EPN would cost approximately $1.3 million for both of their carbon black sites addressed in this rulemaking. However, additional sampling of carbon black oil was included in the rule to improve the accuracy of the mass balance approach. Stack testing once every five years was also added to the provisions to provide additional information regarding compliance.

§112.245

Comment

Tokai requested the TCEQ explain in §112.245(f) what streamlined process exists for the EPA to approve alternatives to test methods specified in the SIP. Otherwise, TCEQ should revise the provisions such that they only refer to minor modifications to test methods or monitoring methods, which the EPA routinely authorizes States to grant.

Response

In response to this comment, the TCEQ included language consistent with 30 TAC §115.725(m) to allow minor modification to monitoring and test methods approved by the TCEQ in each division. In addition, language was added to clarify that increases in the frequency of monitoring and replacement of parametric monitoring with direct emissions monitoring can be approved under this provision.

§112.247

Comment

Tokai requested TCEQ delete §112.247(c), which requires conducting a "full system audit" as a contingency measure if the EPA determines the Hutchinson County SO_2 nonattainment area fails to achieve attainment, and instead refer to TCEQ's existing enforcement policies. Tokai stated that TCEQ's FSA provision suggests that TCEQ will limit its enforcement of the NAAQS to the required reporting scheme, which may be contrary to what EPA envisioned in issuing its guidance, and that the FSA provisions require Tokai to identify exceptional events under 40 CFR §50.14, but these demonstrations are the responsibility of a State, federal land manager, or other federal agency, not a regulated entity. Tokai also stated that TCEQ's FSA provision implies that the EPA only issues findings of failure to attain when actual air quality does not meet the NAAQS, which is at odds with how the EPA handled recent determinations. Tokai gave as an example, the EPA finding for St. Bernard Parish, LA, which was based on its review of Title V deviation reports, despite the presence of valid monitoring data consistent with a finding of attainment. Tokai further commented that if a similar outcome occurred for Hutchinson County, a systems audit focused on local meteorology and monitoring data would *not* generate any useful data.

Response

The commission proposed the full system audits throughout the rules to receive information from sites within a nonattainment area after a finding of failure to attain on the conditions at each site that may have contributed to the finding. The commission notes that the audits are triggered by notices from the TCEQ, not from the finding itself. If it is clear from available information, (ambient monitoring, modeling, compliance reports, etc.) that a site was not responsible for a failure to attain, the TCEQ would not require a full system audit of that site. However, because it may not be clear which site(s) contributed to the EPA's finding, under some circumstances the commission may require the audits for all sites in the nonattainment area. At adoption, the wording is changed so that sites are not required to identify an exceptional event but rather any emissions event(s) and the conditions that existed at their site during the relevant period. The commission recognizes that an EPA finding of failure to attain could be based on Title V deviation reports as well as other information but also that the information from the audits may be important for determining if other conditions within the nonattainment area with a potential to affect conditions leading to the EPA's finding were occurring at the same time.

§112.248

Comment

As in §112.208, the EPA commented for §112.248 that it is not clear what schedule is intended for the installation of controls or making reductions and modifications and that a detailed analysis of what is needed to meet each requirement and what constitutes "as expeditiously as practicable" for each requirement.

Response

In response to this comment, the TCEQ reevaluated the compliance dates to ensure that compliance is achieved as soon as practicable, depending on site specific constraints. Upon the effective date of the rule there will be just over two years before the compliance date of January 1, 2025. Tokai indicated that they will need to design, construct, and install natural gas duct burners and a new flare and are concerned that supply chain issues my impact the schedule. As a result, they have indicated that they cannot comply before January 1, 2025. Because the soonest practicable date for compliance is January 1, 2025, the term "as soon as practicable" was removed from the provisions at adoption.

<u>Subchapter G (Arcosa)</u>

§112.301

Comment

Arcosa requested TCEQ change definition of Lightweight aggregate to one based on ASTM methods.

Response

The commission agrees with this request, and the change is made at adoption.

Comment

Arcosa requested TCEQ delete definition of pipeline quality natural gas in case BACT or other requirements change in the future.

Response

Because Arcosa committed to installing a CEMS on the stack for the control of the lightweight aggregate kiln, the monitoring of the sulfur content of fuels and other materials is not needed. Therefore, the definition of "pipeline quality natural gas" is not needed and is removed at adoption.

§112.302

Comment

Arcosa stated they will install a wet or dry scrubber or other controls as needed to comply and requested TCEQ change the requirements to the following: minimum stack height of 120 feet; minimum exhaust gas velocity of 42.5 feet per second; emissions from EPN E3-1 not to exceed 222 lb/hr of SO_2; minimum exhaust gas temperature of 117 degrees Fahrenheit; and the stack to be located within the area forming a 20 m (65.6 ft) x 30 m (94.4 ft) rectangle just north of the existing stack (EPN E3-1) location (map provided). Arcosa requested that emission limit of 222 lb/hr of SO_2 replaced the two different emission limits contingent on stack parameters. Arcosa also committed to installing a CEMS to continuously monitor SO_2 emissions from the stack.

Response

The requested stack parameters provided by Arcosa were modeled by the TCEQ. The modeling demonstrates that an emission rate of 222 lb/hr is protective of the NAAQS given the stack parameters provided by Arcosa regardless of where the future stack is built within the rectangular area under consideration for construction. Because the changes from Arcosa are based on the control(s) they committed to install and continue to model attainment, the commission agrees that these changes are appropriate. The requested changes to the rule are made at adoption. The TCEQ welcomes Arcosa's commitment to installing a CEMS.

Comment

The EPA commented that the term “lightweight kiln” in §112.302(b) should be changed to “lightweight aggregate kiln” or defined.

Response

The inadvertent omission of “aggregate” in the rule language is corrected at adoption in this subsection, which was re-lettered at adoption.

Comment

The EPA commented that the 200 lb/hr sulfur in fuel limit in §112.302(f) corresponds to emitting 400 lb/hr by itself and does not account for the sulfur content of the materials processed. The EPA commented further that the provisions of §112.306(7) mean that the sulfur content limits in §112.302 should be half of the emission limits provided.

Response

Because Arcosa committed to installing a CEMS to continuously monitor SO_2 emissions and the rules are changed at adoption to require the CEMS. The rule requirement for monitoring the sulfur content of fuels is no longer necessary because emissions will be directly measured, and the provision is removed at adoption. No change was made to the rule in response to this comment.

Comment

The EPA commented that the specific cutoffs for the transition from startup to normal operations are defined but may be difficult to identify during operations in the physical sense; it may take anywhere from 30 minutes to 24 hours to end the startup mode and begin firing solid fuel. The EPA stated that during these first 24 hours the feed rate might be less than 60% of the maximum feed rate, but as it is described, the kiln is still being heated and fed raw materials. The EPA was concerned that there are unquantified amounts of SO_2 emissions from the raw materials and small amounts of SO_2 from the natural gas firing. The EPA stated these emissions need to be quantified correctly, taking into account all sulfur that is being combusted during this startup mode. The EPA also stated that there may be significantly more SO_2 coming off the raw aggregate during startup than the permitted 0.1 lb/hr. The EPA expects this to be one of the conditions tested and stated that this must be added to the requirements of Chapter 112. The EPA commented that the same can be said for the shutdown period, which begins with the cessation of the kiln firing and the addition of raw materials, but the kiln continues to turn until all the final load of hot aggregate traverses the length of the kiln. Without evidence to the contrary, the EPA must assume that there is more than 0.1 lb/hr of SO_2 being emitted by the hot aggregate in 24 hours, even as it cools, during this shutdown period. The EPA expects this to be another condition tested and added to the requirements of Chapter 112.

Response

The CEMS unit to be added to the stack will measure emissions during startup and shutdown. No other testing or rule changes are needed for these periods. No change to the rules was made in response to this comment.

Comment

The EPA encouraged clarification and examples of what is needed to comply with the dual emission limits provided and the ramifications of noncompliance with any of the stack parameter requirements associated with each emission limit.

Response

Because the changes requested in Arcosa's comments result in the removal of the dual emission limits from the rule, clarification and examples are not needed. The commission notes that noncompliance with any of the adopted rule requirements after the compliance date is subject to enforcement.

§112.303

Comment

Arcosa requested TCEQ delete proposed requirements for monitoring fuels and shale in §112.303(1) - (5).

Response

Because a CEMS is the best option for monitoring SO_2 emissions, the requirements for monitoring the sulfur content of fuels and raw materials are not needed and are removed at adoption.

Comment

The EPA commented that an initial stack test is insufficient as monitoring with a CEMS being more appropriate and the need for a CEMS should be evaluated for this site in particular. The EPA commented further that testing or monitoring of the efficiency of any add on controls is needed.

Response

The rule was revised at adoption to require the use of a CEMS to directly monitor sulfur emissions, which minimizes the need for extensive performance testing; however, an initial performance test as well as relative accuracy audits are required by the rule.

Comment

The EPA commented that the use of the term “monitor” is ambiguous in §112.303(1) and (2) and should be changed to “measure” and that the word “any” in §112.303(1) and (5) should be changed to “every.”

Response

Because the specific paragraphs in which the EPA requested these changes are removed at adoption, no change was made in response to this comment.

Comment

The EPA commented that the reference to “natural gas” in §112.303(3) should use the defined term “pipeline quality natural gas.” The EPA commented further that the provision allowing use of an analysis supplied by the supplier should require use of such analysis if the rules do not prescribe how Arcosa must conduct such analysis, including any standard analysis or minimum standards.

Response

Because Arcosa committed to installing a CEMS to continuously monitor SO_2 emissions, §112.303(3) is not needed and is removed at adoption. No change was made in response to this comment.

Comment

The EPA commented that allowing periods longer than an hour for monitoring the sulfur content of fuels or raw materials must be justified and supported by Arcosa's historical records, preferably on an hourly basis, that support longer periods. For the provision in §112.303(5) providing for use of vendor data on fuel or raw material sulfur content, the EPA commented that the materials must have the sulfur content measured directly. The EPA stated that §112.303(6) must specify the frequency of continuous monitoring of exhaust temperature and velocity. The EPA commented further that allowing longer periods and the sampling of combined raw materials makes a root cause analysis of any exceedance difficult but that installing a CEMS would remove the need to sample input materials and would satisfy the requirement for continuous. monitoring of exhaust temperature and velocity.

Response

Because Arcosa committed to installing a CEMS to continuously monitor SO_2 emissions, the provisions in §112.303 for periods greater than an hour are not needed and are removed at adoption. No change was made in response to this comment.

Comment

The EPA noted that §112.303 does not provide a limit on the allowed sulfur content but requires measurement thereof and that the records of calculations of sulfur content of materials processed on an hourly basis are required in §112.306(6) and stated that this only works if the sulfur content of fuels and raw materials are tested hourly.

Response

Because Arcosa committed to installing a CEMS to continuously monitor SO_2 emissions, the daily testing provisions in §112.303 are not needed and are removed at adoption. Changes to §112.306 are also made at adoption, as discussed for that rule section, to account for the recordkeeping appropriate for the use of a CEMS. No change was made in response to this comment.

§112.304 and §112.305

Comment

Arcosa requested TCEQ change requirements to be consistent with the standard federal monitoring and testing requirements for CEMS including 40 CFR §60.8 and §60.13 and 40 CFR Part 60, Appendix B.

Response

The commission agrees that testing requirements and methods appropriate for a

CEMS for SO_2 emissions are appropriate in these sections. Changes are made at adoption to provide the testing provisions appropriate for a CEMS. In addition to 40 CFR §60.8 and §60.13, and 40 CFR Part 60, Appendix B, the rule is updated at adoption to include compliance with 40 CFR Part 60, Appendix F, Quality Assurance Procedures

Comment

The EPA commented that because Arcosa is not required to install an SO_2 control device, an initial stack test under in §112.304 is needed prior to the compliance date so there is time to fix any problems that might be found in the testing. The EPA commented further that the testing should be required within 90 days after the effective date of the rules with submission of the report to TCEQ 60 days thereafter because those dates are closer to "as expeditiously as practicable." The EPA requested confirmation that the provisions in §112.304(c) is intended to require a new stack test if there is a change in the blend of raw materials processed during the initial stack test and for clarification of what changes in raw materials or testing would require retesting. The EPA stated that installation of a CEMS would remove the need for such testing. The EPA requested that the manner of enforcing the testing requirements in §112.304 be specified.

Response

Because Arcosa has committed to installing a CEMS consistent with 40 CFR Part 60, Subpart A and Appendix B, the requirements for a performance test need to conform to 40 CFR §60.8. Changes to §112.304 are made at adoption to reflect the testing required for a CEMS. Additional testing, including any triggered by changes in raw materials, are no longer needed because the emissions will be directly monitored with a CEMS.

Comment

For §112.304(d), the EPA commented that the phrase “maximum anticipated sulfur content” must be defined or clarified for EPA to review and determine the meaning and that a methodology for the stack test should be provided.

Response

Because Arcosa committed to installing a CEMS to continuously monitor SO_2 emissions, §112.304(d) is not needed and is removed at adoption. No change was made in response to this comment.

Comment

The EPA commented that §112.304(f) should be clarified on the parameters that should be analyzed for raw materials.

Response

Because Arcosa committed to installing a CEMS to continuously monitor SO_2 emissions, §112.304(f) is not needed and is removed at adoption. No change was made in response to this comment.

Comment

The EPA recommended that §112.305(b) require that a testing protocol must be approved by the EPA and TCEQ 90 days prior to stack testing. The EPA stated that otherwise they would consider the stack test void.

Response

Because Arcosa committed to installing a CEMS for monitoring SO_2 emissions consistent with the EPA's requirements at 40 CFR Part 60, Subpart A and Appendix B, the rules are changed at adoption to be consistent with the use of a CEMS and the EPA's requirements. Because a CEMS will be used to directly monitor emissions additional specifications regarding testing are less significant and approval of a performance testing protocol, is not needed. No change was made in response to this comment.

Comment

The EPA commented that the provision in §112.305(d) stating that testing of raw materials must be done using a method approved by the executive director constitutes and unacceptable and unenforceable executive director's discretion because EPA approval is not also required, which conflicts with long-standing EPA policy.

Response

Because Arcosa committed to installing a CEMS for monitoring SO_2 emissions, the test method for determining the sulfur content of shale is not needed in the rules and are being replaced with the test methods needed for testing a CEMS.

§112.306

Comment

Arcosa requested TCEQ delete §112.306(1) - (4) and (6) - (8) because they are not needed for use of a CEMS.

Response

The recordkeeping associated with monitoring the sulfur content of materials is not needed because Arcosa committed to installing a CEMS for monitoring SO_2 emissions. The provisions related to records of testing needed for providing sulfur

content for use in a mass balance calculation of SO_2 emissions are removed at adoption and replaced with the recordkeeping needed for test requirements appropriate for the use of a CEMS.

Comment

The EPA commented that the first use of "sulfur" in §112.306(7) should be "sulfur dioxide."

Response

The lack of the word "dioxide" was an inadvertent omission in §112.306(7). However, because this paragraph is removed at adoption, as discussed for the prior comment, no change is made to the rule in response to this comment.

§112.308

Comment

The EPA commented that a more expeditious schedule for complying with the rule provisions should be provided.

Response

The TCEQ has evaluated the possibility of requiring compliance sooner than

January 1, 2025, and determined that an earlier compliance date is not practicable. At the time the rule is finalized, there will be just over two years for Arcosa to complete the control device design and purchase, install, and test the new control device and the monitoring system. Given current uncertainties related to the global supply chain, unexpected setbacks are possible during any one of these phases; therefore, compliance before January 1, 2025, may not be reasonably achievable. Because the soonest practicable date for compliance is January 1, 2025, the term "as soon as practicable" was removed from the provisions at adoption.

SUBCHAPTER E: REQUIREMENTS IN THE HOWARD COUNTY NONATTAINMENT AREA

DIVISION 1: REQUIREMENTS FOR THE ALON USA BIG SPRING REFINERY

§§112.100 - 112.108

Statutory Authority

The new sections are adopted under Texas Water Code (TWC), §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new sections are also adopted under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.014, concerning Emission Inventory, which authorizes the commission to require companies whose activities cause emissions of air contaminants to submit information to enable the commission to develop an inventory of emissions; THSC, §382.015,

concerning Power to Enter Property, which authorizes a member, employee, or agent of the commission to enter public or private property to inspect and investigate conditions relating to emissions of air contaminants; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants, as well as require recordkeeping; and THSC, §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe sampling methods and procedures to be used in determining violations of and procedures to be used in determining compliance.

The adopted new sections implement TWC, §5.103 and §5.105 and THSC, §§382.002, 382.011, 382.012, 382.015, 382.016, 382.017, and 382.021.

§112.100. Applicability.

(a) The requirements in this division apply to affected sources at the Alon USA Big Spring Refinery, which is located at 200 Refinery Road in Big Spring, Texas ~~(Regulated Entity Number (RN) 100250869)~~ in the Howard County sulfur dioxide ~~(SO_2)~~ nonattainment area. Affected sources will remain subject to this division regardless of ownership, operational control, or other documentation changes. ~~Once approved by the United States Environmental Protection Agency (EPA), the requirements in this division continue to apply until the EPA approves their removal.~~

(b) Affected sources are designated by the source name and emission point number (EPN) ~~and source name~~ used in the site's New Source Review (NSR) permit as issued on the specified date. The specific affected sources are as follows:

(1) ~~EPN 06ESPPCV,~~ FCCU ESP Stack (EPN 06ESPPCV)~~,~~ in NSR Permit 49154 dated March 12, 2012;

(2) ~~EPN 69TGINC,~~ No. 1 SRU Incinerator Vent (EPN 69TGINC)~~,~~ in NSR Permit 80833 dated October 28, 2020;

(3) ~~EPN 71TGINC,~~ No. 2 SRU Incinerator Vent (EPN 71TGINC)~~,~~ in NSR Permit 80833 dated October 28, 2020;

(4) ~~EPN 14NEASTFLR,~~ North East Flare (EPN 14NEASTFLR)~~,~~ in NSR Permit 80833 dated October 28, 2020;

(5) ~~EPN 02CRUDEFLR,~~ Crude Flare (EPN 02CRUDEFLR)~~,~~ in NSR Permit 80833 dated October 28, 2020;

(6) ~~EPN 05REFMFLR,~~ Reformer Flare (EPN 05REFMFLR)~~,~~ in NSR Permit 80833 dated October 28, 2020, and;

(7) ~~EPN 16SOUTHFLR,~~ South Flare (EPN 16SOUTHFLR)~~,~~ in NSR Permit

80833 dated October 28, 2020.

§112.101. Definitions.

Unless specifically defined in the Texas Clean Air Act (Texas Health and Safety Code, Chapter 382), or in §101.1 or §112.1 of this title (relating to Definitions, respectively), the terms in this division have the meanings commonly used in the field of air pollution control. The following meanings apply in this division unless the context clearly indicates otherwise.

(1) Block one-hour average--An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the next clock hour of the day (e.g., from 12:00:00 to 12:59:59).

(2) Continuous Monitoring--Monitoring for which readings are recorded at least once every 15 minutes.

(3) ~~(2)~~ Howard County sulfur dioxide (SO_2) nonattainment area--The portion of Howard County designated by the United States Environmental Protection Agency (EPA) as nonattainment for the 2010 SO_2 National Ambient Air Quality Standard, 40 Code of Federal Regulations §81.344~~, as published on March 26, 2021 (86 *Federal Register* 16055), effective April 30, 2021~~.

(4) ~~(3)~~ Pipeline quality natural gas--Natural gas containing no more than 0.25 grain of hydrogen sulfide and 5 grains of total sulfur per 100 dry standard cubic feet.

§112.102. Control Requirements.

~~(a) The owner or operator may not change the Regulated Entity Number (RN) or the emission point number (EPN) designation of any source subject to §112.100 of this title (relating to Applicability) or otherwise contravene any of the control requirements in this section without the prior approval of the executive director and the United States Environmental Protection Agency (EPA).~~

(a) ~~(b) EPN 06ESPPCV (~~The FCCU ESP Stack (EPN 06ESPPCV) emissions may not exceed 250.00 pounds per hour (lb/hr) sulfur dioxide (SO_2) on a seven-day rolling average.

(b) ~~(c)~~ The North East Flare (EPN 14NEASTFLR), Crude Flare (EPN 02CRUDEFLR), Reformer Flare (EPN 05REFMFLR), and South Flare (EPN 16SOUTHFLR) may only combust pipeline quality natural gas or combust a refinery gas stream with a maximum sulfur content of 162 parts per million by volume ~~(ppmv)~~ as hydrogen sulfide determined hourly on a three-hour rolling average except as provided for in 40 Code of Federal Regulations §60.103a(h).

(c) ~~(d) EPN 14NEASTFLR (~~North East Flare (EPN 14NEASTFLR) emissions may not exceed 25.00 lb/hr SO_2 during normal operations, and the following limits apply during authorized maintenance, startup, and shutdown (MSS) activities:

(1) emissions may be equal to or greater than 25.01 lb/hr SO_2 but less than 250.01 lb/hr SO_2 in any hour within a calendar day for no more than four calendar days each year;

(2) emissions may be equal to or greater than 250.01 lb/hr SO_2 but less than 500.01 lb/hr SO_2 in any hour within a calendar day for no more than six calendar days each year;

(3) emissions may be greater than or equal to 500.01 lb/hr SO_2 but less than 1,500.01 lb /hr SO_2 in any hour within a calendar day for no more than two calendar days each year;

(4) emissions above 1,500.00 lb/hr SO_2 are prohibited; and

(5) if SO_2 emissions that correspond to more than one range specified in paragraphs (1) – (3) of this subsection occur during a calendar day, only the emissions in the highest range will be used in determining which emissions rate range specified in paragraphs (1) – (3) of this subsection applies to that calendar day.

(d) ~~(e) EPN 02CRUDEFLR (~~Crude Flare (EPN 02CRUDEFLR) emissions may not exceed 51.80 lb/hr SO_2 during normal operations, and the following limits apply during authorized MSS activities:

(1) emissions may be equal to or greater than 51.81 lb/hr SO_2 but less than 250.01 lb/hr SO_2 in any hour within a calendar day for no more than 14 calendar days each year;

(2) emissions may be equal to or greater than 250.01 lb/hr SO_2 but less than 750.01 lb/hr SO_2 in any hour within a calendar day for no more than three calendar days each year;

(3) emissions above 750.00 lb/hr SO_2 are prohibited; and

(4) if SO_2 emissions that correspond to the ranges in both paragraphs (1) and (2) of this subsection occur during a calendar day, only the range in paragraph (2) of this subsection applies to that calendar day;

(e) ~~(f) EPN 05REFMFLR (~~Reformer Flare (EPN 05REFMFLR) emissions may not exceed 103.70 lb/hr SO_2 during normal operations, and the following limits apply during authorized MSS activities:

(1) emissions may be equal to or greater than 103.71 lb/hr SO_2 but less than 250.01 lb/hr SO_2 in any hour within a calendar day for no more than four calendar days each year;

(2) emissions may be equal to or greater than 250.01 lb/hr but less than 750.01 lb/hr SO_2 in any hour within a calendar day for no more than five calendar days each year;

(3) emissions above 750.00 lb/hr SO_2 are prohibited; and

(4) if SO_2 emissions that correspond to the ranges in both paragraphs (1) and (2) of this subsection occur during a calendar day, only the range in paragraph (2) of this subsection applies to that calendar day.

(f) ~~(g) EPN 16SOUTHFLR (~~South Flare (EPN 16SOUTHFLR) emissions may not exceed 118.70 lb/hr SO_2 during normal operations, and the following limits apply during authorized MSS activities;

(1) emissions may be equal to or greater than 118.71 lb/hr SO_2 but less than 250.01 lb/hr SO_2 in any hour within a calendar day for no more than four calendar days each year;

(2) emissions may be equal to or greater than 250.01 lb/hr SO_2 but less

than 500.01 lb/hr SO_2 in any hour within a calendar day for no more than 12 calendar days each year;

(3) emissions may be equal to or greater than 500.01 lb/hr SO_2 but less than 1,696.01 lb/hr SO_2 in any hour within a calendar day for no more than two calendar days each year;

(4) emissions above 1,696.00 lb/hr SO_2 are prohibited; and

(5) if SO_2 emissions that correspond to more than one range specified in paragraphs (1) – (3) of this subsection occur during a calendar day, only the emissions in the highest range will be used in determining which emissions rate range specified in paragraphs (1) – (3) of this subsection applies to that calendar day.

(g) ~~(h) EPN 69TGINC (~~No. 1 SRU Incinerator Vent (EPN 69TGINC) emissions may not exceed 17.03 lb/hr SO_2.

(h) ~~(i) EPN 71TGINC (~~No. 2 SRU Incinerator Vent (EPN 71TGINC) emissions may not exceed 12.78 lb/hr SO_2.

(i) ~~(j)~~ The owner or operator may request an alternate means of control (AMOC) as follows: ~~alternative SO_2 emission limit if dispersion modeling and analysis consistent with the most recent attainment demonstration confirms the alternative~~

~~limit will not increase the modeled regulatory design value in the nonattainment area. The alternative limit and any deviations from the modeling methodology from the most recent attainment demonstration must be approved by the executive director and the EPA.~~

(1) Permitting Requirements. Compliance with this subsection does not relieve any owner or operator of the responsibility to comply with the requirements of §116.110 or §116.151 of this title (relating to Applicability and New Major Source or Major Modification in Nonattainment Area Other Than Ozone, respectively) with respect to the new construction or modification of sources that may emit SO_2 into the air of this state.

(2) Availability of AMOC.

(A) The owner or operator of any site subject to a control requirement in this subchapter may request approval of an AMOC plan using the procedures established in this subsection. The executive director shall review a submitted AMOC and may approve the AMOC plan if it is demonstrated that the plan meets all applicable criteria and procedures of this subsection. The owner or operator who submits an AMOC plan not satisfying the requirements of this section may apply for a site-specific state implementation plan revision approved by the executive director and the United States Environmental Protection Agency (EPA).

(B) An AMOC applicant may apply to the executive director for a waiver of portions of paragraphs (5) and (6) of this subsection.

(C) Application for an AMOC plan does not stay enforcement of regulations in this subchapter.

(D) Any violation of an AMOC plan will be subject to enforcement action as a violation of this subchapter.

(3) Criteria for Approval of AMOC Plans. An AMOC plan may be approved if it meets each of the following criteria, as applicable.

(A) Except as provided for in paragraph (8) of this subsection, all sources covered by the AMOC plan must be and remain at the same site.

(B) If the AMOC plan includes an increase in the lb/hr emission limit for a source subject to the control requirements in this subchapter, the AMOC plan must also include an equivalent decrease in the lb/hr emission limit for one or more sources subject to the control requirements of this subchapter.

(C) The AMOC application must include a demonstration that satisfies the following requirements.

(i) The modeled impacts of all sources affected by the AMOC plan demonstrate no net increase in ground-level concentration, which for purposes of this subparagraph means no net increase in modeled off-property concentration of SO_2, on a highest, first-high basis, at any receptor, *i,* in excess of the lesser of:

(I) $GLC_{crit,i}$, as defined in the following equation; or

Figure 30 TAC §112.102(i)(3)(C)(i)(I)

$$GLC_{\mathrm{crit,i}} = 0.5 \times (196.4\ {}^{\mu g}/_{m^3} - DV_{AD,i}) - (DV - DV_{AD,i})$$

Where:

$GLC_{crit,i}$ = The value for each receptor *i* that the modeled concentration in an AMOC demonstration cannot exceed.

$DV_{AD,i}$ = The maximum design value in any modeled scenario approved by the Environmental Protection Agency under 40 Code of Federal Regulations §51.112(a) for receptor *i*; and

DV = The design value specified by the Executive Director under this section, which, on the effective date of this section, equals DVA_o; and may subsequently be no less than DVA_o.

DVA_o = The design value based on the attainment demonstration modeling for the Howard County SO_2 nonattainment area.

(II) an applicable significant impact level for the one-hour National Ambient Air Quality Standard for SO_2.

(ii) Except where otherwise provided in this subsection, the demonstration required under this paragraph must be by means of applicable air quality models, databases, and other requirements specified in Appendix W to 40 CFR §51.1 and what was used in the modeling for the corresponding SIP revision.

(D) The AMOC must be implemented and reductions created after the effective date of this rule.

(E) The AMOC plan must establish control requirements and monitoring, testing, recordkeeping and reporting requirements consistent with and no less stringent than the applicable requirements of this subchapter for all sources in the plan that render the proposed control requirements enforceable.

(4) Procedures for AMOC Plan Submittal.

(A) The owner or operator requesting an AMOC plan shall submit a proposed AMOC plan and demonstration to the executive director; copies of such plan and demonstration must also be submitted to the appropriate regional office, any local air pollution control program with jurisdiction over the site affected by the AMOC plan, and the EPA regional office.

(B) The proposed AMOC plan must include the following information:

(i) the AMOC applicant name with mailing address, site name with physical address, regulated entity number, and contact person including address and telephone number;

(ii) an identification and a description of the sources involved in the AMOC plan including any applicable air permit numbers, plot plans, detailed flow diagrams, emission point numbers (EPNs), and facility identification numbers (FINs); an identification of the provisions of this subchapter that are applicable to such sources; an identification of promulgated provisions of this subchapter that will be applicable to such sources; and a description of normal operating conditions for each source causing emissions;

(iii) control requirements, which must be established for each source to make emission limits enforceable, to be applicable to each source affected by the proposed AMOC plan;

(iv) a demonstration that the AMOC plan satisfies each applicable requirement of paragraph (3) of this subsection;

(v) a list containing the name, address, and telephone number of any air pollution control program with jurisdiction over the site affected by the AMOC plan; and

(vi) any other relevant information necessary to evaluate the merits and enforceability of the AMOC plan, as may be requested by the executive director.

(C) All representations with regard to the AMOC plan, as well as any provisions attached to the AMOC plan, become conditions upon which the subsequent AMOC plan is issued. If the AMOC plan is approved by the executive director and the EPA, the owner or operator may not vary from such representation or provision if the change will cause a change in the method of control of emissions, the character of the emissions, or will result in an increase in the discharge of the various emissions. If the AMOC plan is approved by the executive director and the EPA, the owner or operator may not vary from the emission limits, control requirements, monitoring, testing, reporting, or recordkeeping requirements of an approved AMOC plan.

(D) Applications to amend or revise an AMOC plan must be submitted subject to the requirements of this subsection.

(5) Procedures for an AMOC Plan Approval. Upon a preliminary determination to approve or deny the proposed AMOC plan, the executive director shall, in writing, so notify the submitter of the plan, any local air pollution control program with jurisdiction over the site affected by the AMOC plan, and the EPA regional office.

(A) If the executive director makes a preliminary determination to approve the AMOC plan, the notice must include a copy of the AMOC plan as preliminarily approved.

(B) If the executive director makes a determination to deny the AMOC plan, the notice must include a description of the reasons for such determination of denial. This determination constitutes a final action of the executive director appealable to the commission as provided in paragraph (7) of this subsection.

(C) Upon receipt of notice from the executive director that the AMOC plan has received preliminary approval, the AMOC applicant, at the applicant's own expense, shall cause notice of the applicant's intent to obtain an AMOC plan and of the opportunity to submit written comments to be published. The notice must be consistent with paragraph (6) of this subsection.

(D) The executive director shall consider and prepare a written response to all significant and timely written comments filed in connection with an AMOC plan.

(E) In response to the written comments, the executive director may modify the provisions of the AMOC plan, deny the AMOC plan, or approve the AMOC plan without changes.

(F) The executive director shall send written notice of the final determination concerning each AMOC plan to the submitter of the plan, the EPA regional office, any local pollution control program with jurisdiction, and to each person who submitted timely written comments. Such notice must include the final AMOC plan provisions, a copy of the response to comments, and an announcement of the opportunity to appeal the executive director's determination to the Commission. The notice required by this subparagraph must be sent by a means evidencing receipt.

(G) Any person entitled to notice under paragraph (6) of this subsection may, within 15 days of the receipt of such notice, file with the executive director an appeal of the final determination on the AMOC plan. Such appeal may be considered at the next regularly scheduled meeting of the Commission for which adequate notice may be made. Based on arguments submitted to the commission during such appeal, the Commission may remand the AMOC determination to the executive director, deny the AMOC plan, or issue the AMOC plan unchanged.

(H) Within 45 days of final approval of the AMOC plan by the executive director or the Commission for an appeal, the EPA may notify the commission of the EPA's disapproval of the executive director's final decision. Such notification must be in writing and must include a statement of the reason(s) for the disapproval and a specific listing of changes to the AMOC plan needed to overcome the disapproval. Any time prior to the expiration of the 45-day period, the EPA may notify the executive director that no disapproval is forthcoming. Upon receipt of a timely EPA disapproval, the executive director shall void or revise the AMOC plan and reissue the notice as required by paragraph (6) of this subsection.

(I) If no appeal of the executive director's decision to approve the AMOC plan is filed pursuant to subparagraph (G) of this paragraph, the AMOC plan becomes effective upon the acceptance of the plan by the EPA as described in subparagraph (K) of this paragraph.

(J) If an appeal of the executive director's decision is filed, the AMOC plan becomes effective upon the latter of the acceptance of the AMOC plan by the Commission or the acceptance of the AMOC plan by the EPA.

(K) EPA acceptance is defined as explicit approval of the AMOC plan by the EPA, notification by the EPA to the executive director that no EPA disapproval is forthcoming, or failure of the EPA to file notice of disapproval within 45 days after the executive director's final decision to approve the AMOC plan.

(6) Public Notice Format.

(A) Public notice must be published in the public notice section of two successive issues of a newspaper of general circulation in or closest to the municipality in which the site affected by the AMOC plan is located.

(B) Public notice must contain the following information:

(i) the AMOC plan application number assigned by the executive director;

(ii) the AMOC applicant's name;

(iii) the type of source and site;

(iv) a description of the location of the site;

(v) a brief description of the AMOC plan;

(vi) the executive director's preliminary determination to approve the plan;

(vii) the locations and availability of copies of the proposed AMOC plan, related documentation, and the executive director's preliminary analysis of the plan (including the Austin and appropriate regional offices, any local pollution control program with jurisdiction over the site affected by the AMOC plan, and the EPA regional office);

(viii) an announcement of the opportunity to submit written comments on the AMOC plan;

(ix) the length of the public comment period, which extends to at least 30 days after the final publication of the notice;

(x) the procedure for submission of written public comments concerning the proposed AMOC plan; and

(xi) the name, address, and phone number of the agency's regional office to be contacted for further information.

(C) The executive director may not take final action on the AMOC plan until the owner or operator who submitted the AMOC plan has provided proof of adequate notice to the executive director, the EPA, and any local pollution control program with jurisdiction.

(7) Review of Approved AMOC Plans and Termination of AMOC Plans.

(A) For the purposes of this subsection, compliance date means the date by which a source must comply with new or modified sections of this subchapter.

(B) Unless revised to reflect new regulatory requirements, an AMOC plan becomes void on the compliance date specified for a new or modified section of this subchapter affecting a source subject to an AMOC plan.

(C) The holder of an AMOC plan shall comply with the requirements of this subchapter if the AMOC plan becomes void.

(D) Upon final approval of an AMOC plan, the owner or operator of the sources affected by the plan shall keep a copy of the plan on the site affected by the plan and shall make the plan available upon request to representatives of the executive director, the EPA, or any local air pollution control agency having jurisdiction in the area.

(E) Upon request, each holder of an AMOC plan shall submit to the executive director a demonstration that the plan continues to meet all applicable criteria of this subsection.

(F) An AMOC holder is responsible for obtaining a new AMOC plan prior to the compliance date of any new or modified regulation of this subchapter that affects a source subject to an AMOC plan.

(8) Inclusion of Contiguous Properties. Notwithstanding paragraph (3)(A) of this subsection, an AMOC plan may cover multiple sources operated on contiguous

properties, provided that separate requests for plan approval are submitted by each owner or operator subject to a control requirement under this subchapter.

§112.103. Monitoring Requirements.

The owner or operator shall continuously monitor equipment subject to sulfur dioxide (SO_2) emission limits or standards in §112.102 of this title (relating to Control Requirements) as follows:

(1) install, operate, calibrate, and maintain a continuous emissions monitoring system (CEMS) as specified in 40 Code of Federal Regulations (CFR) §60.105a(g)(1), (2) and (5) regardless of whether these provisions otherwise apply; use an analyzer with a minimum analyzer accuracy of plus or minus (±) 2.5%, a dedicated totalizing gas flow measurement system with a minimum measurement accuracy of ±5%, and a temperature monitor with a minimum accuracy of ±1%; convert data from all monitoring devices to a common concentration, flow, pressure, and temperature basis and calculate and record 15-minute and subsequent block one-hour average SO_2 emissions from FCCU ESP Stack (EPN 06ESPPCV);

(2) for the North East Flare (EPN 14NEASTFLR), Crude Flare (EPN 02CRUDEFLR), Reformer Flare (EPN 05REFMFLR), and South Flare (EPN 16SOUTHFLR), install, operate, calibrate, and maintain designated instrumentation according to the

manufacturers' specifications to continuously monitor the gas stream flare inlet temperature, the total inlet gas flow rate, and the total sulfur concentration as specified in 40 CFR §60.107a(e) and (f)(1), regardless of whether these provisions otherwise apply or exempt flare activities, as follows: ~~for each inlet gas stream in compliance with the 40 CFR §60.107a(e);~~

(A) monitor the total volumetric flow rate of gases routed to each flare using a separate dedicated totalizing gas flow meter with an accuracy of ±5%;

(B) monitor the temperature of gases routed to each flare using a separate temperature measurement device with an accuracy of ±1%; and

(C) monitor the sulfur content of the combined inlet flare gas stream as follows:

(i) using a separate dedicated analyzer capable of accurately measuring and recording total sulfur (including sulfur dioxide (SO_2), hydrogen sulfide (H_2S), and organic sulfur compounds levels) with an accuracy of ±5% on a continuous basis, the sulfur concentration must be determined in accordance 40 CFR §60.107a(e)(1) regardless of whether these requirements are otherwise applicable or exempt the flare, and hourly SO_2 emissions must be determined using the following equation; or

Figure: 30 TAC §112.103(2)(C)(i)

$$SO_2 = Scc \times FFa \times \frac{Tsc}{Ta} \times \frac{Pa}{Psc} \times \frac{lb\ mole}{385.27\ scf} \times \frac{64.06\ lb\ SO_2}{lb\ mole}$$

Where:

SO_2 = flare sulfur dioxide emissions in pounds per hour;

Scc = inlet sulfur compound concentration in in units of cubic feet of flare gas inlet stream sulfur compounds per 1,000,000 cubic feet of flare gas;

FFa = inlet flare gas stream flow in actual cubic feet per hour;

Psc = regulatory standard condition pressure of 14.7 pounds per square inch (psia);

Pa = FFa measurement pressure in units of psia;

Tsc = regulatory standard condition temperature of 528 degrees Rankin; and

Ta = flare inlet actual stream temperature in degrees Rankin.

(ii) using a separate dedicated analyzer capable of accurately measuring and recording H_2S to an accuracy of ±5% on a continuous basis, determine the H_2S concentration in the flared gas stream, derive an inlet flare gas total sulfur concentration for each monitored hourly H_2S concentration in accordance with 40 CFR §60.107a(e)(2) methodology regardless of whether these requirements are otherwise applicable or exempt the flare, and calculate the SO_2 emissions for each operating hour using the following equation:

Figure: 30 TAC §112.103(2)(C)(ii)

$$SO_2 = H_2Smc \times \frac{Scc}{H_2Ssc} \times FFa \times \frac{Tsc}{Ta} \times \frac{Pa}{Psc} \times \frac{lb\ mole}{385.27\ scf} \times \frac{64.06\ lb\ SO_2}{lb\ mole}$$

Where:

SO_2 = flare sulfur dioxide emissions in pounds per hour;

H_2Smc = monitored combined inlet flare stream hydrogen sulfide (H_2S) concentration in units of cubic feet of H_2S per 1,000,000 cubic feet of flow;

Scc = sampled composite inlet flare stream total sulfur compound concentration in units of cubic feet of total sulfur per 1,000,000 cubic feet of sample;

H_2Ssc = sampled composite H_2S concentration in units of cubic feet of H_2S per 1,000,000 cubic feet of sample;

FFa = inlet gas stream flare flow in units of actual cubic feet per hour;

Psc = regulatory standard condition pressure of 14.7 pounds per square inch (psia);

Pa = FFa measurement pressure in units of psia;

Tsc = regulatory standard condition temperature of 528 degrees Rankin; and

Ta = FFa measurement temperature in degrees Rankin.

(3) separately for SRU1 Incinerator Stack (EPN 69TGINC) and SRU2 Incinerator Stack (EPN 71TGINC), install, operate, calibrate, and maintain a CEMS as specified in 40 CFR §60.106a(a), regardless of whether these provisions otherwise apply; use an analyzer with a minimum accuracy of ±2.5%, a dedicated totalizing gas flow measurement system with an accuracy of ±5%, and temperature indicator with an accuracy of ±1% convert data from all monitoring devices to a common concentration, flow, pressure, and temperature basis and calculate ~~to~~ and record ~~EPN 69TGINC and EPN 71TGINC~~15-minute and subsequent block one-hour average SO_2 emissions; ~~and~~

(4) continuous monitoring data collected in accordance with requirements in this subsection must undergo an appropriate quality assurance and quality control process and be validated for at least 95% of the time that the monitored emission point has emissions; an owner or operator must utilize the most accurate data substitution methodology available that is at least equivalent to engineering judgement and replace all missing or invalidated monitoring data for the entire period the monitored emission point has emissions; and~~.~~

(5) minor modifications to monitoring methods may be approved by the executive director. Monitoring methods other than those specified in this section may be used if approved by the executive director and validated by 40 CFR Part 63, Appendix A, Test Method 301. For the purposes of this subsection, substitute "executive director" in each place that Test Method 301 references "administrator." These validation procedures may be waived by the executive director or a different protocol may be granted for site-specific applications. Minor modifications that may be approved under this subsection include increases in the frequency of monitoring and the replacement of parametric monitoring with direct emissions monitoring with a CEMS provided appropriate quality assurance control, accuracy specifications, and data validation requirements are specified and no less stringent than monitoring requirements for a comparable EPN in this division.

§112.104. Testing Requirements.

By the compliance date in §112.108 of this title (relating to Compliance Schedule), the owner or operator shall comply with the following:

(1) perform continuous emissions monitoring system relative accuracy tests for equipment installed to meet the requirements of §112.103 of this title (relating to Monitoring Requirements) in accordance with 40 Code of Federal Regulations (CFR) §60.105a(g)(2) for the FCCU EPS Stack (EPN 06RSPPCV) and 40 CFR §60.106a(1)(iii) for the No. 1 SRU Incinerator Vent (EPN 69TGINC)~~,~~ and No. 2 SRU Incinerator Vent (EPN 71TGINC);

(2) perform initial and subsequent testing of ~~for the flare~~ monitoring devices required by §112.103 of this title in accordance with the manufacturer's specifications to ensure that the required monitoring instrumentation is properly ~~monitors are~~ calibrated and functional ~~function properly~~. Initial testing must be completed by the applicable compliance date in §112.108 of this title. If a monitoring device was previously tested in accordance with the manufacturer's specifications and a record is available to document proper procedures were followed, then an owner or operator is not required to repeat the initial testing again under these provisions; and

(3) conduct additional performance testing, if requested by the executive director, in compliance with 40 CFR §60.104a to demonstrate compliance with applicable emission limits or standards. The notification requirements of 40 CFR §60.8(d) apply to each initial performance test and to each subsequent performance

test required by the executive director, except for performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments. All performance tests must be conducted using test methods allowed in §112.105 of this title (relating to Approved Test Methods).

§112.105. Approved Test Methods.

(a) Tests required under §112.104 of this title (relating to Testing Requirements) must be conducted using the test methods in 40 Code of Federal Regulations (CFR) Part 60, Appendices A-1 through A-8 and Appendix B or other methods as specified in this section, except as provided in 40 CFR §60.8(b).

(b) Fuel and waste gas sulfur ~~Sulfur~~ content ~~of fuels~~ must be determined using ~~(~~American Society for Testing and Materials (ASTM) Method D6667 (Determination of Total Volatile Sulfur in Gaseous Hydrocarbons), ASTM Method D1945 (Standard Test Method for Analysis of Natural Gas by Gas Chromatography), United States Environmental Protection Agency (EPA) Method 15A or 16A of Appendix A to 40 CFR Part 60, ASTM Method D4468, or ASTM Method D5504 if it is conducted in a manner that analyzes all sulfur-containing compounds present. ~~D1945-91 ASTM Method D3588-93 for fuel composition.~~

(c) Sulfur dioxide (SO_2) in exhaust gases must be determined using ~~United States~~

~~Environmental Protection Agency (~~EPA~~)~~ Test Method 6 or 6C (40 CFR, Part 60, Appendix A).

(d) For flares subject to emissions limitations or standards in §112.102 of this title (relating to Control Requirements), the owner or operator shall use flare test methods and procedures in 40 CFR §60.104a.

(e) ~~(d)~~ Alternate methods as approved by the executive director and the EPA may be used.

§112.106. Recordkeeping Requirements.

The owner or operator shall maintain records in written or electronic format sufficient to demonstrate compliance with this division for a minimum of five years, including but not limited to the following:

(1) all monitoring data and sampling analyses, including but not limited to continuous emission monitoring system data and sulfur composition data, used to quantify emissions;

(2) the methodology and any associated calculations used to determine compliance;

(3) documentation of any period that emission limits or standards were exceeded and copies of required exceedance reports submitted to the appropriate Texas Commission on Environmental Quality Regional Office; and

(4) copies of required emission test data and records.

§112.107. Reporting Requirements.

(a) If a source subject to an emissions limit in §112.102 of this title (relating to Control Requirements) exceeds an applicable emission limit or fails to meet a required stack parameter, the owner or operator shall submit to the Texas Commission on Environmental Quality (TCEQ) Regional Office for the area where the plant is located a report by March 31 of the year after an exceedance occurs documenting the excess emissions during the preceding calendar year, including but not limited to the following:

(1) the date that each exceedance or failure to meet a required stack parameter occurred;

(2) an explanation of the exceedance or failure to meet a required stack parameter, including the specific rule citation from §112.102 of this title;

(3) a statement of whether the exceedance or failure to meet a required

stack parameter was concurrent with either an authorized maintenance, startup, or shutdown ~~MSS~~ activity for, or a malfunction of, an affected source ~~facility~~ or control system;

(4) a description of the corrective action taken, if any; and

(5) a written statement, signed by the owner or operator, certifying the accuracy and completeness of the information contained in the report.

(b) The owner or operator shall submit a copy of each test report for any testing conducted under §112.104 of this title (relating to Testing Requirements) to the TCEQ Regional Office and any local air pollution control agency having jurisdiction for the area where the plant is located within 60 days after completion of the test.

(c) After the effective date of a determination by the Environmental Protection Agency (EPA) that the Howard County sulfur dioxide (SO_2) nonattainment area has failed to attain the 2010 one-hour SO_2 National Ambient Air Quality Standard or failed to meet reasonable further progress (RFP) pursuant to federal ~~Federal~~ Clean Air Act §179(c), 42 United States Code §7509(c), the TCEQ will notify the owner or operator of the failure to attain and that the contingency measures in this subsection are triggered. Once notification is received from the TCEQ, the owner or operator shall perform a full system audit (FSA) of all SO_2 sources subject to §112.100 of this title (related to Applicability).

(1) Within 90 calendar days after the date of the notification, the owner or operator shall submit the FSA, including recommended provisional SO_2 emission control strategies as necessary, to the executive director of the TCEQ.

(2) As part of the FSA, the owner or operator shall conduct a root cause analysis of the circumstances surrounding the cause of the determination of failure to attain or failure to meet RFP, including a review and consideration of the following:

(A) for all causes of the determination of failure to attain or failure to meet RFP, at a minimum, hourly mass emissions of SO_2 from each SO_2 source subject to this division; and

(B) for a determination of failure to attain based on ambient air monitor data or modeling data, at a minimum, the meteorological conditions recorded at the monitor or other relevant meteorological data, including the frequency distribution of wind direction temporally correlated with SO_2 readings greater than 75 parts per billion at the monitor for which the EPA's determination of failure to attain was made; and any emissions ~~exceptional~~ event that may have occurred. The root cause analysis and associated records used to conduct the audit must consider information on the days that monitored exceedances occurred during the time period that the EPA evaluated in making the failure to attain determination.

§112.108. Compliance Schedules.

The owner or operator shall comply with the requirements applicable to FCCU ESP Stack (EPN 06ESPPCV), No. 2 SRU Incinerator Vent (EPN 69TGINC), and No. 2 SRU Incinerator Vent (EPN 71TGINC), no later than November 1, 2023. The owner or operator ~~of an affected source subject to §112.100 of this title (relating to Applicability)~~ shall comply with the requirements of this division applicable to all other sources ~~as soon as practicable, but~~ no later than January 1, 2025.

SUBCHAPTER E: REQUIREMENTS IN THE HOWARD COUNTY NONATTAINMENT AREA

DIVISION 2: REQUIREMENTS FOR THE TOKAI BIG SPRING CARBON BLACK PLANT

§§112.110 - 112.118

Statutory Authority

The new sections are adopted under Texas Water Code (TWC), §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new sections are also adopted under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.014, concerning Emission Inventory, which authorizes the commission to require companies whose activities cause emissions of air contaminants to submit information to enable the commission to develop an inventory of emissions; THSC, §382.015,

concerning Power to Enter Property, which authorizes a member, employee, or agent of the commission to enter public or private property to inspect and investigate conditions relating to emissions of air contaminants; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants, as well as require recordkeeping; and THSC, §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe sampling methods and procedures to be used in determining violations of and procedures to be used in determining compliance.

The adopted new sections implement TWC, §5.103 and §5.105 and THSC, §§382.002, 382.011, 382.012, 382.015, 382.016, 382.017, and 382.021.

§112.110. Applicability.

(a) The requirements in this division apply to affected sources at the Tokai Big Spring Carbon Black Plant, which is located at 1211 North Midway Road in Big Spring, Texas, ~~(Regulated Entity Number (RN) 100226026)~~ in the Howard County sulfur dioxide ~~(SO_2)~~ nonattainment area. Affected sources will remain subject to this division regardless of ownership, operational control, or other documentation changes.

(b) Affected existing sources are designated by the source name and emission point number (EPN) ~~and source name~~ used in the site's New Source Review (NSR) permit as issued on the specified date. Applicable control devices to be authorized and constructed are similarly designated by the EPN that the company used to designate the future unit in the attainment demonstration modeling, with an appropriate name also used in the rules. The specific affected sources are as follows:

(1) ~~EPN 13A,~~ Incinerator + HRSG (EPN 13A)~~,~~ in NSR Permit 6580 dated November 23, 2021;

(2) ~~EPN 7A,~~ Dryer Stack Units Nos. 1 & 2 (EPN 7A)~~,~~ in NSR Permit 6580 dated November 23, 2021;

(3) ~~EPN 12A,~~ Dryer Stack Units No. 3 (EPN 12A)~~,~~ in NSR Permit 6580 dated November 23, 2021;

(4) ~~EPN Flare-1,~~ Flare 1 (EPN Flare-1)~~,~~ in NSR Permit 6580 dated November 23, 2021;

(5) ~~EPN Flare-2,~~ Flare 2 (EPN Flare-2)~~,~~ in NSR Permit 6580 dated November 23, 2021;

(6) ~~EPN Flare-3,~~ Flare 3 (EPN Flare-3)~~,~~ in NSR Permit 6580 dated November 23, 2021; and

(7) ~~EPN FLARE 4,~~ Flare 4 (EPN FLARE 4)~~,~~ if authorized and constructed to replace the existing three flares for the carbon black reactors (EPN Flare-1, EPN Flare-2, and EPN Flare-3).

§112.111. Definitions.

Unless specifically defined in the Texas Clean Air Act (Texas Health and Safety Code, Chapter 382), or in §101.1 or §112.1 of this title (relating to Definitions, respectively), the terms in this division have the meanings commonly used in the field of air pollution control. The following meanings apply in this division unless the context clearly indicates otherwise.

(1) Block one-hour average--An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the next clock hour of the day (e.g., from 12:00:00 to 12:59:59).

(2) Continuous Monitoring--Monitoring for which readings are recorded at least once every 15 minutes.

(3) ~~(2)~~ Howard County sulfur dioxide (SO_2) nonattainment area--The portion of Howard County designated by the United States Environmental Protection Agency as nonattainment for the 2010 SO_2 National Ambient Air Quality Standard, 40 Code of Federal Regulations §81.344~~, as published on March 26, 2021 (86 *Federal*~~

~~*Register* 16055), effective April 30, 2021~~.

(4) ~~(3)~~ Off-line--With respect to a carbon black oil furnace, a period when either:

(A) only natural gas and combustion air are supplied to the furnace burners (no oil is supplied to the furnace burners), and the furnace is not manufacturing carbon black or generating tail gas; or

(B) the oil furnace is not operating.

(5) ~~(4)~~ On-line--Not “off-line,” as defined in paragraph (4) ~~(3)~~ of this subsection.

~~(5) Pipeline quality natural gas--Natural gas containing no more than 0.25 grain of hydrogen sulfide and 5 grains of total sulfur per 100 dry standard cubic feet.~~

(6) Production unit--The combined equipment used in the manufacture of carbon black, including but not limited to, carbon black oil furnaces or reactors, bag unit filters, cyclones, fans, and carbon black dryers as specified in this rule. Production Units 1 and 2 consist of nine carbon black oil furnaces that produce tail gas and five carbon black dryers that combust tail gas and exhaust emissions through Dryer Stack Units Nos. 1 & 2 (Emission Point Number (EPN) 7A). Production Unit 3 consists of four

carbon black oil furnaces that produce tail gas and two carbon black dryers that combust tail gas and exhaust emissions through Dryer Stack Unit No. 3 (EPN 12A). A portion of the tail gas from all of the furnaces is also combusted in the Incinerator + HRSG (EPN 13A) or by Flare 4 (EPN Flare 4).

(7) Tail gas--The exit gaseous stream of a carbon black oil furnace consisting of water vapor, carbon monoxide, hydrogen, pyrolysis by-products, and reduced and organic sulfur compounds as a result of the manufacture of carbon black.

§112.112. Control Requirements.

~~(a) The owner or operator may not change the Regulated Entity Number (RN) or the emission point number (EPN) designation of any source subject to §112.110 of this title (relating to Applicability) or otherwise contravene any of the control requirements in this section without the prior approval of the executive director and the United States Environmental Protection Agency (EPA).~~

(a) ~~(b)~~ Production Units 1 and 2 together are prohibited from operating with only one furnace on-line and Production Unit 3 is prohibited from operating with only one furnace on-line. Affected sources in §112.110 of this title (relating to Applicably) may not exceed the following pounds per hour (lb/hr) sulfur dioxide (SO_2) limits based on the number of furnaces on-line in Production Units 1 and 2 and in Production Unit 3:

Figure: 30 TAC §112.112(a)

~~**Figure: 30 TAC §112.112(b)**~~

Production Units 1 and 2 Furnaces On-line	Production Unit 3 Furnaces On-line	SO_2 Emission Limit Cap (lb/hr) for EPN 13A, Flare 4, EPN 7A, and EPN 12A ~~12A~~	SO_2 Emission Limit (lb/hr) for EPN 13A or Flare 4	SO_2 Emission Limit Subcap (lb/hr) for EPN 7A and EPN 12A	SO_2 Emission Limit (lb/hr) for EPN 12A
9	4	1,355.00	1,138.00	407.00	146.00
9	3	1,253.38	1,052.65	376.48	109.50
9	2	1,151.75	967.30	345.95	73.00
~~9~~	~~1~~	~~1,050.13~~	~~881.95~~	~~315.43~~	~~36.50~~
9	0	948.50	796.60	284.90	0.00
8	4	1,249.61	1,049.49	375.34	146.00
8	3	1,147.99	964.14	344.82	109.50
8	2	1,046.36	878.79	314.29	73.00
~~8~~	~~1~~	~~944.74~~	~~793.44~~	~~283.77~~	~~36.50~~
8	0	843.11	708.09	253.24	0.00
7	4	1,144.22	960.98	343.69	146.00
7	3	1,042.60	875.63	313.16	109.50
7	2	940.97	790.28	282.64	73.00
~~7~~	~~1~~	~~839.35~~	~~704.93~~	~~252.11~~	~~36.50~~
7	0	737.72	619.58	221.59	0.00
6	4	1,038.83	872.47	312.03	146.00
6	3	937.21	787.12	281.51	109.50
6	2	835.58	701.77	250.98	73.00
~~6~~	~~1~~	~~733.96~~	~~616.42~~	~~220.46~~	~~36.50~~
6	0	632.33	531.07	189.93	0.00
5	4	933.44	783.96	280.38	146.00
5	3	831.82	698.61	249.85	109.50
5	2	730.19	613.26	219.33	73.00
~~5~~	~~1~~	~~628.57~~	~~527.91~~	~~188.80~~	~~36.50~~
5	0	526.94	442.56	158.28	0.00
4	4	828.06	695.44	248.72	146.00
4	3	726.43	610.09	218.20	109.50
4	2	624.81	524.74	187.67	73.00
~~4~~	~~1~~	~~523.18~~	~~439.39~~	~~157.15~~	~~36.50~~
4	0	421.56	354.04	126.62	0.00
3	4	722.67	606.93	217.07	146.00

3	3	621.04	521.58	186.54	109.50
3	2	519.42	436.23	156.02	73.00
~~3~~	~~1~~	~~417.79~~	~~350.88~~	~~125.49~~	~~36.50~~
3	0	316.17	265.53	94.97	0.00
2	4	617.28	518.42	185.41	146.00
2	3	515.65	433.07	154.89	109.50
2	2	414.03	347.72	124.36	73.00
~~2~~	~~1~~	~~312.40~~	~~262.37~~	~~93.84~~	~~36.50~~
2	0	210.78	177.02	63.31	0.00
~~1~~	~~4~~	~~511.89~~	~~429.91~~	~~153.76~~	~~146.00~~
~~1~~	~~3~~	~~410.26~~	~~344.56~~	~~123.23~~	~~109.50~~
~~1~~	~~2~~	~~308.64~~	~~259.21~~	~~92.71~~	~~73.00~~
~~1~~	~~1~~	~~207.01~~	~~173.86~~	~~62.18~~	~~36.50~~
~~1~~	~~0~~	~~105.39~~	~~88.51~~	~~31.66~~	~~0.00~~
0	4	406.50	341.40	122.10	146.00
0	3	304.88	256.05	91.58	109.50
0	2	203.25	170.70	61.05	73.00
~~0~~	~~1~~	~~101.63~~	~~85.35~~	~~30.53~~	~~36.50~~

(b) ~~(c)~~ If ~~if~~ during any block one-hour period the number of furnaces on-line changes, ~~the fewest number of furnaces on-line at any time during that block one-hour period must be used to calculate~~ the emission limit~~.~~ must be determined by one of the following methods:

(1) the fewest number of furnaces on-line in each production unit during any fraction of the hour; or

(2) the time-weighted average of all limits applying during any fraction of the hour, calculated using the following equation:

Figure: 30 TAC §112.112(b)(2)

$$L_{EPN,1-hr} = \frac{1}{60}\sum_{t=1}^{60} L_{EPN,t}$$

Where

$L_{EPN,\ 1hr}$ = the time-weighted average of all limits applying during any fraction of the particular one-hour block period, i.e., one sixtieth of the sum of the limits applying during each one-minute fraction of the particular one-hour block period; and

$L_{EPN,t}$ limits applying during each one-minute fraction of an hour.

(c) ~~(d)~~ The maximum emission rate of SO_2 allowed under ~~subsections (b) – (f) of~~ this section ~~for each EPN specified under subsections (b) – (e) of this section for each operational scenario occurring~~ during any block one-hour period must be determined on a block one-hour average.

(d) The emission cap identified in §112.112(a) of this section is the maximum emission limit that applies to the sum of the emissions from the Incinerator + HRSG (EPN 13A), Flare 4 (EPN Flare 4), Dryer Stack Units Nos. 1 & 2 (EPN 7A), and Dryer Stack Unit No. 1 (EPN 12A), and the subcap identified in §112.112(a) of this section is the maximum emission limit that applies to the sum of the emissions from Dryer Stack Units Nos. 1 & 2 (EPN 7A) and Dryer Stack Units No. 3 (EPN 12A).

(e) Tail gas may only be combusted in sources whose emissions are routed to the Incinerator + HRSG (EPN 13A), Flare 4 (EPN Flare 4), Dryer Stack Units Nos. 1 & 2 (EPN 7A), and ~~or~~ Dryer Stack Unit No. 1 (EPN 12A ~~12 A~~).

(f) Simultaneous operation of the Incinerator + HRSG (EPN 13A) and Flare 4 (EPN FLARE 4) during any block one-hour period is prohibited.

(g) Sulfur or sulfur containing compounds may not be routed to Flare 1 (EPN Flare-1), Flare 2 (EPN Flare-2), and Flare 3 (EPN Flare-3) ~~may not be operated~~ on or after the compliance date in §112.118 of this title (relating to Compliance Schedule).

(h) After construction and commencement of operation, if authorized, Flare 4 (EPN FLARE 4) must have a stack height of ~~no less than~~ 60.35 meters and must be located at Universal Transverse Mercator (UTM) coordinates UTM East Meters 273185 and UTM North Meters 3573987 in UTM Zone 14.~~;~~

(i) ~~EPN 13A (~~Incinerator + HRSG (EPN 13A) must have a stack height of ~~no less than~~ 65.00 meters no later than ~~upon~~ the compliance date in §112.118 of this title (relating to Compliance Schedules).

(j) The owner or operator may request an alternate means of control under the provisions of §112.102(i) of this title (relating to Control Requirements).~~alternative SO_2 emission limit if dispersion modeling and analysis consistent with the most recent attainment demonstration confirms the alternative limit will not increase the modeled regulatory design value in the nonattainment area. The alternative limit and any deviations from the modeling methodology from the most recent attainment demonstration must be approved by the executive director and the EPA.~~

§112.113. Monitoring Requirements.

(a) For each block one-hour period of operation, the owner or operator shall calculate total SO_2 emissions generated by ~~from~~ each production unit using the following equation.

Figure: 30 TAC §112.113(a)

$$\sigma_i = [(S_{oil} \times D_{oil} \times F_{oil}) - (S_p \times P_p)] \times 2$$

Where:

σ_i = emissions of sulfur dioxide (SO_2) generated by each production unit in units of pounds per hour;

i = the carbon black production unit;

S_{oil} = weight of sulfur in carbon black oil in units of pound of sulfur per pound of carbon black oil;

D_{oil} = density of carbon black oil in pounds per gallon, determined at a temperature consistent with the carbon black oil feed;

F_{oil} = feed rate of oil to carbon black production unit in gallons per hour;

S_p = sulfur content of carbon black product as determined in units of pound of sulfur per pound of product;

P_p = production rate of carbon black product in units of pounds per hour; and

2 = the molecular weight ratio of SO_2 to sulfur.

$$\cancel{\sigma_i = (SI_i - SRB_i) \times 2\,; \quad i = 1, 2, 3}$$

~~Where:~~

~~σ_i = emissions of SO_2 expressed in units of lb/hr;~~

~~i = the carbon black production unit;~~

~~SI_i = the mass rate of sulfur input to production unit i, expressed in units of lb/hr;~~

~~SRB_i = the mass rate of sulfur retained in the carbon black produced by production unit i, expressed in units of lb/hr; and~~

~~2 = the molecular weight ratio of SO_2 to sulfur~~

(b) The owner or operator shall calculate the ~~Calculate~~ SO_2 emissions from ~~EPN 13A (~~Incinerator + HRSG (EPN 13A), ~~EPN 7A (~~Dryer Stack Units Numbers 1 and 2 (EPN 7A), ~~EPN 13A (~~Dryer Stack Units Number 3 (EPN 12A), and ~~EPN FLARE 4 (~~Flare 4 (EPN FLARE 4) for each block one-hour period of operation during which emissions of SO_2 are emitted from the emission points listed in this subsection, using the following equations ~~equation.~~

~~**Figure: 30 TAC §112.113(b)**~~

$$\cancel{SO_{2,EPN} = \pi \times \sum_{i \in \tau} \sigma_i}$$

~~**Parameter**~~	~~**Emission Point Number**~~			
	~~**13A**~~	~~**7A**~~	~~**12A**~~	~~**FLARE 4**~~
~~Π~~	~~π_{incin}~~	~~π_{dryer}~~	~~π_{dryer}~~	~~π_{incin}~~
~~Τ~~	~~1,2,3~~	~~1,2~~	~~3~~	~~1,2,3~~

~~Where:~~

~~$SO_{2,EPN}$ = emissions of SO_2 expressed in units of lb/hr for each EPN;~~

~~π_{incin} and π_{dryer} are the split coefficients from §112.113(4)(E) and (F), respectively, indicating the fraction of tail gas combusted in the Incinerator + HRSG or flare and in dryers, determined through continuous monitoring as required in this subsection.~~

~~i = the carbon black production unit;~~

~~τ = the set of carbon black production units contributing carbon black oil furnace tail gas to the applicable EPN; and~~

~~σ_i = emissions of SO_2 expressed in units of lb/hr;~~

(1) for the Incinerator + HRSG (EPN 13A), calculate the emission rate using the following equation);

Figure: 30 TAC §112.113(b)(1)

$$SO_{2,EPN13A} = \sum_{i=1}^{3} \pi_{incin,i} \times \sigma_i$$

Where:

$SO_{2,EPN13A}$ = emissions of sulfur dioxide (SO_2) expressed in units of pounds per hour (lb/hr) for EPN 13A;

$\pi_{incin,i}$ = the split coefficients from §112.113(e)(4) of this section indicating the fraction of tail gas combusted in the Incinerator + HRSG from each production unit to the total tail gas generated by each production unit i, determined through continuous monitoring as required in this subsection;

i = the carbon black production unit; and

σ_i = emissions of SO_2 expressed in units of lb/hr calculated using the equation in §112.113(a) of this section.

(2) for Dryer Stack Units No. 1 & 2 (EPN 7A), calculate the emission rate

using the following equation;

Figure: 30 TAC §112.113(b)(2)

$$SO_{2,EPN7A} = \sum_{i=1}^{2} \pi_{dryer,i} \times \sigma_i$$

Where:

$SO_{2,EPN7A}$ = emissions of sulfur dioxide (SO_2) expressed in units of pounds per hour (lb/hr) for EPN 7A;

$\pi_{dryer,i}$ = the split coefficients from §112.113(e)(4) and (5) of this section respectively, indicating the fraction of tail gas combusted in the dryers from each production unit to the total tail gas generated by each production unit *i*, determined through continuous monitoring as required in this subsection;

i = the carbon black production unit; and

σ_i = emissions of SO_2 expressed in units of lb/hr calculated using the equation in §112.113(a) of this section.

(3) for Flare 4 (EPN Flare 4), calculate the emission rate using the following equation; and

Figure: 30 TAC §112.113(b)(3)

$$SO_{2,EPNFlare4} = \sum_{i=1}^{3} \pi_{incin,i} \times \sigma_i$$

Where:

$SO_{2,EPNFLARE4}$ = emissions of sulfur dioxide (SO_2) expressed in units of pounds per hour (lb/hr) for EPN Flare 4;

$\pi_{incin,i}$ = the split coefficients from §112.113(e)(4) of this section indicating the fraction of tail gas combusted in the flare from each production unit to the total tail gas generated by each production unit *i*, determined through continuous monitoring as required in this subsection.

i = the carbon black production unit;

σ_i = emissions of SO_2 expressed in units of lb/hr calculated using the equation in §112.113(a) of this section.

(4) for Dryer Stack Unit No. 3 (EPN 12A), calculate the emission limit using the following equation.

Figure: 30 TAC §112.113(b)(4)

$$SO_{2,EPN12A} = \pi_{dryer,3} \times \sigma_3$$

Where:

$SO_{2,EPN12A}$ = emissions of sulfur dioxide (SO_2) expressed in units of pounds per hour for EPN 12A;

$\pi_{dryer,3}$ = the split coefficient from §112.113(e)(5) of this section indicating the fraction of tail gas combusted in the in the dryers from Production Unit 3, determined through continuous monitoring as required in this subsection;

i = the carbon black production unit; and

σ_3 = emissions of SO_2 expressed in units of pounds per hour calculated using the equation in §112.113(a) of this section.

(c) The owner or operator shall install ~~Install~~, calibrate, maintain, and operate one or more totalizing fuel flow meters, consistent with manufacturer's specifications, with an accuracy of ± 5%, to continuously measure the feed rate of carbon black oil feedstock supplied to each carbon black production unit.

(d) The owner or operator shall install ~~Install~~, calibrate, maintain, and operate totalizing tail gas flow meters, consistent with manufacturer's specifications, with an accuracy of ± 5%, to continuously measure the volumetric flow rate of tail gas to each tail gas combustion device covered under §112.112 of this title (relating to Control Requirements). Tail gas combustion devices include the dryers, Incinerator + HRSG, and Flare 4.

(e) The owner or operator shall use ~~Use~~ a continuous data acquisition system that continuously measures, calculates, and records the following quantities:

(1) the volumetric flow rate of tail gas to the Incinerator + HRSG (EPN 13A) ~~(Incinerator + HRSG)~~ and Flare 4 (EPN Flare 4) ~~(Flare 4)~~ from each production unit;

(2) the volumetric flow rate of tail gas to the ~~each~~ carbon black dryers in each production unit; ~~dryer comprising Production Units 1 and 2, which exhaust through EPN 7A, and Production Unit 3, which exhausts through EPN 12A;~~

(3) the total volumetric flow rate of tail gas from each production unit; ~~to all of the carbon black dryers;~~

~~(4) the volumetric flow rate of tail gas to all tail gas combustion devices;~~

(4) ~~(5)~~ for each production unit, the ratio of quantities in paragraphs (1)

and (3) ~~(4)~~ of this subsection, identified as "π_{incin}", which is the split coefficient for the Incinerator + HRSG and for Flare 4 used in the calculations in subsection (b) of this section; and

(5) ~~(6)~~ for each production unit, the ratio of quantities in paragraphs (2) ~~(3)~~ and (3) ~~(4)~~ of this subsection, identified as "π_{dryer}", which is the split coefficient for the dryers used in the calculations in subsection (b) of this section.

(f) The owner or operator shall install, ~~Install,~~ calibrate, maintain, and operate the continuous data acquisition system specified in subsection (e) ~~(d)~~ of this section in accordance with the manufacturer's recommended procedures.

(g) The owner or operator shall measure twice daily (at least four hours apart) ~~Measure daily~~ the sulfur content by weight of the carbon black oil in the feed to each production unit according to the requirements of §112.115(b) of this title (relating to Approved Test Methods).

(h) For each grade of carbon black produced, the owner or operator shall measure daily the sulfur content by weight of the carbon black produced by each carbon black production unit in accordance with ~~according to the requirements of~~ §112.115(c) of this title.

(i) The owner or operator shall determine ~~Determine~~ the amount of each grade of carbon black produced by each carbon black production unit ~~for~~ each hour.

(j) In lieu of the monitoring requirements of §112.113(a) - (i) of this section, the owner or operator may install, calibrate, and maintain a continuous emissions monitoring system to monitor exhaust sulfur dioxide (SO_2) from Incinerator + HRSG (EPN 13A), Dryer Stack Units Nos. 1 & 2 (EPN 7A), or Dryer Stack Units No. 3 (EPN 12A) in accordance with the requirements of 40 Code of Federal Regulations (CFR) §60.13, 40 CFR Part 60, Appendix B, Performance Specification 2 and 6, for SO_2, and 40 CFR Part 60, Appendix F, quality assurance procedures. If a CEMS is not used to monitor the emissions from all three EPNs, monitoring requirements in §112.11(a) - (i) continue to apply for EPNs without a CEMS.

(k) ~~(j)~~ Continuous monitoring data collected in accordance with requirements in this section must undergo an appropriate quality assurance and quality control process and be validated for at least 95% of the time that the monitored emission point has emissions; an owner or operator must utilize an appropriate data substitution process based on the most accurate methodology available, which is at least equivalent to engineering judgement, to obtain all missing or invalidated monitoring data for the remaining period the monitored emission point has emissions.

(l) Minor modifications to monitoring methods may be approved by the executive director. Monitoring methods other than those specified in this section may be used if approved by the executive director and validated by 40 CFR Part 63,

Appendix A, Test Method 301. For the purposes of this subsection, substitute "executive director" in each place that Test Method 301 references "administrator." These validation procedures may be waived by the executive director or a different protocol may be granted for site-specific applications. Minor modifications that may be approved under this subsection include increases in the frequency of monitoring provided appropriate quality assurance control, accuracy specifications, and data validation requirements are specified and no less stringent than monitoring requirements for a comparable EPN in this subchapter.

§112.114. Testing Requirements.

(a) The owner or operator shall perform ~~Perform~~ an initial demonstration of compliance test on the emission points specified in §112.112 of this title (relating to Control Requirements) for sulfur dioxide ~~(SO_2)~~, except for flares, while the associated sources ~~facilities~~ are firing tail gas, by the compliance date in §112.118 of this of this title (relating to Compliance Schedules). The owner or operator shall perform additional performance tests at least every five years.

(b) The owner or operator shall use ~~Use~~ the methods provided in §112.115 of this title (relating to Approved Test Methods) for the initial demonstration of compliance test required under subsection (a) of this section.

(c) During performance ~~stack~~ testing the owner or operation shall operate the source ~~facility~~ at the maximum rated capacity, or as near thereto as practicable.

(d) The owner or operator shall conduct ~~Conduct~~ additional performance testing, if requested by the executive director. All performance tests must be conducted using test methods allowed in §112.115 of this title.

(e) If a CEMS is installed, operated, calibrated, and maintained, in accordance with the requirements in this division, to monitor emissions from any EPN subject to this division, the requirement to conduct performance testing once every 5 years no longer applies to that EPN.

§112.115. Approved Test Methods.

(a) Tests required under §112.114 of this title (relating to Testing Requirements) must be conducted using the test methods in 40 Code of Federal Regulations (CFR) Part 60, Appendices A-1 through A-8 and Appendix B or other methods as specified in this section, except as provided in 40 CFR §60.8(b).

(b) Sulfur content of fuels and carbon black oil must be determined using American Society for Testing and Materials (ASTM) Method D4294 ~~D1945-91 or ASTM Method D3588-93 for fuel composition~~.

(c) Sulfur content of carbon black must be determined using ASTM Method

D1619.

(d) Sulfur dioxide ~~(SO_2)~~ in exhaust gases must be determined using United States Environmental Protection Agency (EPA) Test Method 6 or 6C (40 CFR, Part 60, Appendix A).

(e) For flares subject to emissions limitations or standards in §112.112 of this title (relating to Control Requirements), the owner or operator shall use flare test methods and procedures in 40 CFR §60.104a as if the federal rules apply to carbon black plants.

(f) ~~(e)~~ Alternate methods as approved by the executive director and the EPA may be used.

§112.116. Recordkeeping Requirements.

The owner or operator shall maintain records in written or electronic format sufficient to demonstrate compliance with each applicable requirement for a minimum of five years, including but not limited to the following:

(1) records, in units of pounds per hour, of production of carbon black for each grade of carbon black from each carbon black production unit;

(2) twice-daily ~~daily~~ records of sulfur content by weight of the carbon black oil feedstock;

(3) daily records of sulfur content by weight of the carbon black produced for each grade of carbon black produced by each carbon black production unit;

(4) records of continuous carbon black oil feedstock flow rates for each carbon black production unit;

(5) records of continuous tail gas volumetric flow rates to each tail gas combustion device covered by §112.112 of this title (relating to Control Requirements); and

(6) for each block one-hour period of operation of a carbon black production unit:

(A) records of the identification of each furnace on-line each minute of each ~~during the~~ block one-hour period;

(B) records of the applicable emission limit of sulfur dioxide (SO_2) as determined by §112.112 of this title during the block one-hour period, including any calculations conducted under §112.112(b) of this title;

(C) records of all information identified ~~factors used in the calculations~~ in §112.113 of this title (relating to Monitoring Requirements) ~~of the actual emissions~~ and the required mass balance calculations of emissions of SO_2 for each emission point number with SO_2 emissions during the block one-hour period;

(7) documentation of any period that emission limits or standards were exceeded, and copies of exceedance reports submitted to the appropriate Texas Commission on Environmental Quality regional office; and

(8) copies of test reports for tests conducted in accordance with §112.114 of this title and associated ~~required emission test data and~~ records.

§112.117. Reporting Requirements.

(a) If a source that is subject to an emissions limit in §112.112 of this title (relating to Control Requirements) exceeds the applicable emission limit or fails to meet a required stack parameter, the owner or operator shall submit to the Texas Commission on Environmental Quality (TCEQ) Regional Office for the area where the plant is located a report by March 31 of the year after an exceedance occurs documenting the excess emissions during the preceding calendar year, including but not limited to the following:

(1) the date that each exceedance or failure to meet a required stack parameter occurred;

(2) an explanation of the exceedance or failure to meet a required stack parameter~~, including the specific rule citation from §112.112 of this title~~;

(3) a statement of whether the exceedance or failure to meet a required stack parameter was concurrent with either an authorized maintenance, startup, or shutdown activity for, or a malfunction of, an affected source ~~facility~~ or control system;

(4) a description of the corrective action taken, if any; and

(5) a written statement, signed by the owner or operator, certifying the accuracy and completeness of the information contained in the report.

(b) The owner or operator shall submit a copy of each test report for any testing conducted under §112.114 of this title (relating to Testing Requirements) to the TCEQ Regional Office and any local air pollution control agency having jurisdiction for the area where the plant is located within 60 days after completion of the test.

(c) After the effective date of a determination by the United States Environmental Protection Agency (EPA) that the Howard County sulfur dioxide (SO_2)

nonattainment area has failed to attain the 2010 one-hour SO_2 National Ambient Air Quality Standard or failed to meet reasonable further progress (RFP) pursuant to federal ~~Federal~~ Clean Air Act §179(c), 42 United States Code §7509(c), the TCEQ will notify the owner or operator of the failure to attain and that the contingency measures in this subsection are triggered. Once notification is received from the TCEQ, the owner or operator shall perform a full system audit (FSA) of all SO_2 sources subject to §112.110 of this title (relating to Applicability).

(1) Within 90 calendar days after the date of the notification, the owner or operator shall submit the FSA, including recommended provisional SO_2 emission control strategies as necessary, to the executive director of the TCEQ.

(2) As part of the FSA, the owner or operator shall conduct a root cause analysis of the circumstances surrounding the cause of the determination of failure to attain or failure to meet RFP, including a review and consideration of the following:

(A) for all causes of the determination of failure to attain or failure to meet RFP, at a minimum, hourly mass emissions of SO_2 from each SO_2 source subject to this division; and

(B) for a determination of failure to attain based on ambient air monitor data or modeling data, at a minimum, the meteorological conditions recorded at the monitor or other relevant meteorological data, including the frequency distribution of wind direction temporally correlated with SO_2 readings greater than 75 parts per billion at the monitor for which the EPA's determination of failure to attain was made; and any emissions ~~exceptional~~ event that may have occurred. The root cause analysis and associated records used to conduct the audit must consider information on the days that monitored exceedances occurred during the time period that the EPA evaluated in making the failure to attain determination.

§112.118. Compliance Schedules.

The owner or operator of an affected source subject to §112.110 of this title (relating to Applicability) shall comply with the requirements of this division ~~as soon as practicable, but~~ no later than January 1, 2025.

SUBCHAPTER F – REQUIREMENTS IN THE HUTCHINSON COUNTY NONATTAINMENT AREA

DIVISION 1 – REQUIREMENTS FOR THE CHEVRON PHILLIPS CHEMICAL BORGER PLANT

§§112.200 - 112.203, 112.206 - 112.208

Statutory Authority

The new sections are adopted under Texas Water Code (TWC), §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new sections are also adopted under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.014, concerning Emission Inventory, which authorizes the commission to require companies whose activities cause emissions of air contaminants to submit information to enable the commission to develop an inventory of emissions; THSC, §382.015,

concerning Power to Enter Property, which authorizes a member, employee, or agent of the commission to enter public or private property to inspect and investigate conditions relating to emissions of air contaminants; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants, as well as require recordkeeping; and THSC, §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe sampling methods and procedures to be used in determining violations of and procedures to be used in determining compliance.

The adopted new sections implement TWC, §5.103 and §5.105 and THSC, §§382.002, 382.011, 382.012, 382.015, 382.016, 382.017 and 382.021.

§112.200. Applicability.

(a) The requirements in this division apply to affected sources at the Chevron Phillips Chemical Borger Plant, which is located in Borger, Texas at latitude 35.696666 and longitude -101.359722 ~~(Regulated Entity Number (RN) 102320850)~~ in the Hutchinson County sulfur dioxide ~~(SO_2)~~ nonattainment area. Affected sources will remain subject to this division regardless of ownership, operational control, or other documentation changes. ~~Once approved by the United States Environmental Protection Agency (EPA), the requirements in this division continue to apply until the EPA approves their removal.~~

(b) Affected sources are designated by the source name and emission point number (EPN) used in the site's New Source Review (NSR) permit as issued on the specified date. The affected sources are as follows:

(1) ~~EPN F-M2A,~~ Sulfolene Handling Area (EPN F-M2A)~~,~~ in NSR Permit 21918 dated February 5, 2019;

(2) ~~EPN FL-1,~~ North Flare (EPN FL-1)~~,~~ in NSR Permit 21918 dated February 5, 2019; and

(3) ~~EPN FL-2,~~ South Flare, (EPN FL-2)~~,~~ in NSR Permit 21918 dated February 5, 2019.

§112.201. Definitions.

Unless specifically defined in the Texas Clean Air Act (Texas Health and Safety Code, Chapter 382) or §101.1 or §112.1 of this title (relating to Definitions, respectively), the terms in this division have the meanings commonly used in the field of air pollution control. The following meanings apply in this division unless the context clearly indicates otherwise.

(1) Block one-hour average--An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the

next clock hour (e.g., from 12:00:00 to 12:59:59).

(2) Continuous Monitoring--Monitoring for which readings are recorded at least once every 15 minutes.

(3) ~~(2)~~ Hutchinson County sulfur dioxide (SO_2) nonattainment area--The portion of Hutchinson County designated by the United States Environmental Protection Agency as nonattainment for the 2010 SO_2 National Ambient Air Quality Standard, 40 Code of Federal Regulations §81.344~~, as published on March 26, 2021 (86 *Federal Register* 16055), effective April 30, 2021~~.

~~(3) Pipeline quality natural gas--Natural gas containing no more than 0.25 grain of hydrogen sulfide and 5 grains of total sulfur per 100 dry standard cubic feet.~~

§112.202. Control Requirements.

~~(a) The owner or operator may not change the Regulated Entity Number (RN) or emission point number (EPN) designation of any source subject to §112.200 of this title (relating to Applicability) or otherwise contravene any of the control requirements in this section without the prior approval of the executive director and the United States Environmental Protection Agency (EPA).~~

(a) ~~(b) EPN F-M2A (~~Sulfolene Handling Area (EPN F-M2A) emissions may not exceed the following:

(1) the emissions from the sulfolene building and trailer(s) at that location (EPN F-M2A_1 in the attainment demonstration modeling) may not exceed 0.98 ~~1.00~~ pound per hour (lb/hr) sulfur dioxide (SO_2); and

(2) the emissions from the parking/storage area for trailer(s) with sulfolene (EPN F-M2A_2 in the attainment demonstration modeling) may not exceed 1.00 ~~0.98~~ lb/hr SO_2.

(b) ~~(c)~~ The combined emissions from the ~~EPN FL-1 (~~North Flare (EPN FL-1) and ~~EPN FL-2 (~~South Flare (EPN FL-2) may not exceed 430.00 lb/hr SO_2.

(c) ~~(d)~~ The owner or operator may request an alternate means of control under the provisions of §112.232(k) of this title (relating to Control Requirements). ~~alternative SO_2 emission limit if dispersion modeling and analysis consistent with the most recent attainment demonstration confirms the alternative limit will not increase the modeled regulatory design value in the nonattainment area. The alternative limit and any deviations from the modeling methodology from the most recent attainment demonstration must be approved by the executive director and the EPA.~~

§112.203. Monitoring Requirements.

(a) For the ~~EPN F-M2A (~~Sulfolene Handling Area (EPN F-M2A), the owner or operator shall track hourly the weight of sulfolene stored and shall monitor the temperature on an hourly basis inside the sulfolene handling building and each trailer containing sulfolene. The emissions from EPN F-M2A must be calculated as follows:

(1) for the sulfolene handling building and each trailer storing sulfolene, enter the hourly measured weight of sulfolene stored into the following equation;

Figure: 30 TAC §112.203(a)(1)

$$SO_2 = Wt \times Dec\%_{sulfolene}$$

Where:

SO_2 = sulfur dioxide emissions in units of pounds per hour;

Wt = weight of sulfolene in storage during the hour in units of pounds; and

$Dec\%_{sulfolene}$ = decomposition factor for sulfolene calculated using the equation in §112.203(a)(2) of this subsection.

(2) enter into the equation in §112.203(a)(1) the decomposition factor corresponding to the measured temperature for that hour in the sulfolene handling building or trailer, as appropriate, calculated using the following equation;

Figure: 30 TAC §112.203(a)(2)

$$Dec\,\%_{sulfolene} = \frac{8.821921}{[(1 + e^{12.429479+(0.007527\times time)}) \times (1 + e^{8.743395-(0.071099\times temp)})]}$$

Where

Dec%$_{sulfolene}$ = the percentage of the weight of sulfolene that decomposes;

e = Euler's number, which is a mathematical constant approximately equal to 2.71828;

time = the number of hours that the sulfolene has been at the monitored temperature; and

temp = the monitored temperature in degrees Fahrenheit.

(3) calculate the emissions for the specific trailer or the sulfolene handling building;

(4) sum the emissions for the sulfolene handling building and all trailers at location F-M2A_1; and

(5) sum the emissions for all trailers at location F-M2A_2.

(b) The owner or operator shall monitor ~~Monitor~~ the sulfur content of gases routed to ~~EPN FL-1 (~~North Flare (EPN FL-1) and to ~~EPN FL-2 (~~South Flare (EPN FL-2) by using separate analyzers that are installed, calibrated, maintained, and operated according to the manufacturer's specifications, which are capable of accurately measuring and recording hydrogen sulfide~~, sulfur dioxide (SO_2)~~, and organic sulfur compounds levels ~~to the range of 1 part per million by volume (ppmv)~~ on a continuous basis with an accuracy of ±2.5% of full scale for concentrations greater than 50 parts per million. To account for the *de minimis* levels of sulfur dioxide in the gases sent to the South Flare, the owner or operator shall add 0.015 pound per hour of SO_2 to each hourly calculation of SO_2 emissions from the South Flare.

(c) The owner or operator shall monitor ~~Monitor~~ the volumetric flow rate of gases routed to the ~~EPN FL-1 (~~North Flare (EPN FL-1) and to the ~~EPN FL-2 (~~South Flare (EPN FL-2) using separate totalizing gas flow meters with an accuracy of ±5% that are installed, calibrated, maintained, and operated according to ~~per~~ the manufacturer's specifications ~~directions~~.

(d) The owner or operator shall calculate the SO_2 emissions from North Flare (EPN FL-1) South Flare (EPN FL-2) using the following equation with the addition of 0.015 pound per hour of SO_2 to each hourly calculation of SO_2 emissions from the South Flare:

Figure: 30 TAC §112.203(d)

$$SO_2 = Scc \times FFa \times \frac{Tsc}{Ta} \times \frac{Pa}{Psc} \times \frac{lb\ mole}{385.27\ scf} \times \frac{64.06\ lb\ SO_2}{lb\ mole}$$

Where:

SO_2 = Sulfur dioxide emissions in units of pounds per hour;

Scc = inlet sulfur compound concentration in cubic feet per 1,000,000 cubic feet of waste gas;

FFa = inlet waste gas stream flow in actual cubic feet per hour;

Psc = regulatory standard condition pressure of 14.7 pounds per square inch (psia);

Pa = FFa measurement pressure in units of psia;

Tsc = regulatory standard condition temperature of 528 degrees Rankin; and

Ta = inlet actual stream temperature in degrees Rankin.

(e) ~~(d)~~ Continuous monitoring data collected in accordance with requirements in this subsection must undergo an appropriate quality assurance and quality control process and be validated for at least 95% of the time that the monitored emission point has emissions; an owner or operator must utilize an appropriate data substitution process based on the most accurate methodology available, which is at least equivalent to engineering judgement, to obtain all missing or invalidated monitoring data for the remaining period the monitored emission point has emissions.

(f) Minor modifications to monitoring methods may be approved by the executive director. Monitoring methods other than those specified in this section may be used if approved by the executive director and validated by 40 CFR Part 63, Appendix A, Test Method 301. For the purposes of this subsection, substitute "executive director" in each place that Test Method 301 references "administrator." These validation procedures may be waived by the executive director or a different protocol may be granted for site-specific applications. Minor modifications that may be approved under this subsection include increases in the frequency of monitoring and the replacement of parametric monitoring with direct emissions monitoring with a continuous emissions monitoring system provided appropriate quality assurance control, accuracy specifications, and data validation requirements are specified and no less stringent than monitoring requirements for a comparable EPN in this division.

§112.206. Recordkeeping Requirements.

The owner or operator shall maintain records in written or electronic format of the following continuous monitoring parameters for a minimum of five years:

(1) for ~~EPN F-M2A (~~sulfolene handling areas (EPN F-M2A), hourly records of the following:

(A) ~~both~~ the temperature inside the sulfolene handling building (part of EPN F-M2A_1 in the attainment demonstration modeling) and each storage trailer holding sulfolene; ~~and~~

(B) the amount of sulfolene stored in the sulfolene handling building and each trailer during each hour, the time and weight of each amount of sulfolene bagged and kept in the sulfolene handling building for more than an hour, and the time and weight of each amount of sulfolene placed in each trailer; ~~,~~

(C) whether each storage ~~the~~ trailer is located near the sulfolene handling building (EPN F-M2A_1 in the attainment demonstration modeling) or in the trailer parking area (EPN F-M2A_2 in the attainment demonstration modeling); ~~and~~

(D) the calculated SO_2 emissions from the sulfolene handling building and each storage trailer;

(E) the sum of SO_2 emissions from the sulfolene handling building and the adjacent trailers; and

(F) the sum of SO_2 emissions from the trailer parking area;

(2) the sulfur content and flow rate of gases routed to the ~~EPN FL-1~~ ~~(~~North Flare (EPN FL-1) and to the ~~EPN FL-1 (~~South Flare (EPN FL-2) and the emission rate calculations from this monitoring, as well as the specific time periods that each flare was in use; and~~.~~

(3) documentation of any period that emission limits or standards were exceeded and copies of required exceedance reports submitted to the appropriate Texas Commission on Environmental Quality Regional Office.

§112.207. Reporting Requirements.

(a) For a source that is subject to an emissions limit in §112.202 of this title (relating to Control Requirements) and that exceeds an applicable emission limit or fails to meet a required stack parameter, the owner or operator shall submit to the

Texas Commission on Environmental Quality (TCEQ) Regional Office for the area where the plant is located a report by March 31 of the year after an exceedance occurs documenting the excess emissions during the preceding calendar year, including at least the following:

(1) the date that each exceedance or failure to meet a required stack parameter occurred;

(2) an explanation of the exceedance or failure to meet a required stack parameter;

(3) a statement of whether the exceedance or failure to meet a required stack parameter was concurrent with a maintenance, startup, or ~~and~~ shutdown period for, or malfunction of, an affected source ~~facility~~ or control system;

(4) a description of the action taken, if any; and

(5) a written statement, signed by the owner or operator, certifying the accuracy and completeness of the information contained in the report.

~~(b) The owner or operator shall submit the exceedance report in subsection (a) of this section to the TCEQ Regional Office for the area where the plant is located annually with documentation of the results of the hourly monitoring of temperature in~~

~~the trailers containing sulfolene. Any period when the monitored temperature within any trailer exceeded 125 degrees Fahrenheit must be noted in the report as having been above the maximum temperature used in testing to determine the emission rate for the sulfolene handling area used in attainment demonstration modeling.~~

(b) ~~(c)~~ After the effective date of a determination by the United States Environmental Protection Agency (EPA) that the Hutchinson County sulfur dioxide (SO_2) nonattainment area has failed to attain the 2010 one-hour SO_2 National Ambient Air Quality Standard or failed to meet reasonable further progress (RFP) pursuant to federal ~~Federal~~ Clean Air Act §179(c), 42 United States Code §7509(c), the TCEQ will notify the owner or operator of the failure to attain and that the contingency measures in this subsection are triggered. Once notification is received from the TCEQ, the owner or operator shall perform a full system audit (FSA) of all SO_2 sources subject to §112.200 of this title (relating to Applicability).

(1) Within 90 calendar days after the date of the notification, the owner or operator shall submit the FSA, including recommended provisional SO_2 emission control strategies as necessary, to the executive director of the TCEQ.

(2) As part of the FSA, the owner or operator shall conduct a root cause analysis of the circumstances surrounding the cause of the determination of failure to attain or failure to meet RFP, including a review and consideration of the following:

(A) for all causes of the determination of failure to attain or failure to meet RFP, at a minimum, hourly mass emissions of SO_2 from each SO_2 source subject to this division; and

(B) for a determination of failure to attain based on ambient air monitor data or modeling data, at a minimum, the meteorological conditions recorded at the monitor or other relevant meteorological data, including the frequency distribution of wind direction temporally correlated with SO_2 readings greater than 75 parts per billion at the monitor for which the EPA's determination of failure to attain was made; and any emissions ~~exceptional~~ event that may have occurred. The root cause analysis and associated records used to conduct the audit must consider information on the days that monitored exceedances occurred during the time period that the EPA evaluated in making the failure to attain determination.

§112.208. Compliance Schedules.

The owner or operator of a source subject to §112.200 of this title (relating to Applicability) shall comply with the requirements of this division ~~as soon as practicable, but~~ no later than January 1, 2025.

SUBCHAPTER F – REQUIREMENTS IN THE HUTCHINSON COUNTY NONATTAINMENT AREA

DIVISION 2: REQUIREMENTS FOR THE IACX ROCK CREEK GAS PLANT

§§112.210 - 112.213, 112.216 - 112.218

Statutory Authority

The new sections are adopted under Texas Water Code (TWC), §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new sections are also adopted under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.014, concerning Emission Inventory, which authorizes the commission to require companies whose activities cause emissions of air contaminants to submit information to enable the commission to develop an inventory of emissions; THSC, §382.015,

concerning Power to Enter Property, which authorizes a member, employee, or agent of the commission to enter public or private property to inspect and investigate conditions relating to emissions of air contaminants; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants, as well as require recordkeeping; and THSC, §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe sampling methods and procedures to be used in determining violations of and procedures to be used in determining compliance.

The adopted new sections implement TWC, §5.103 and §5.105 and THSC, §§382.002, 382.011, 382.012, 382.015, 382.016, 382.017 and 382.021.

§112.210. Applicability.

(a) The requirements in this division apply to affected sources at the IACX Rock Creek Gas Plant, which is located at 1000 West Tenth Street in Borger, Texas ~~(Regulated Entity Number (RN) 100216613)~~ in the Hutchinson County sulfur dioxide ~~(SO_2)~~ nonattainment area. Affected sources will remain subject to this division regardless of ownership, operational control, or other documentation changes. ~~Once approved by the United States Environmental Protection Agency (EPA), the requirements in these rules continue to apply until the EPA approves their removal.~~

(b) Affected sources are designated by the source name and emission point number (EPN) used in the site's New Source Review (NSR) permit as issued on the specified date. The specific affected sources are as follows:

(1) ~~EPN FLR1,~~ Acid Gas Flare (EPN FLR1)~~,~~ in NSR Permit 3131A dated July 12, 2011; and

(2) ~~EPN INCIN1,~~ Acid Gas Incinerator (EPN INCIN1)~~,~~ in NSR Permit 3131A dated July 12, 2011.

§112.211. Definitions.

Unless specifically defined in the Texas Clean Air Act (Texas Health and Safety Code, Chapter 382), or in §101.1 or §112.1 of this title (relating to Definitions, respectively), the terms in this division have the meanings commonly used in the field of air pollution control. The following meanings apply in this division unless the context clearly indicates otherwise.

(1) Block one-hour average--An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the next clock hour (e.g., from 12:00:00 to 12:59:59).

(2) Continuous Monitoring— Monitoring for which readings are recorded

at least once every 15 minutes.

(3) ~~(2)~~ Hutchinson County sulfur dioxide (SO_2) nonattainment area--The portion of Hutchinson County designated by the United States Environmental Protection Agency (EPA) as nonattainment for the 2010 SO_2 National Ambient Air Quality Standard, 40 Code of Federal Regulations §81.344~~, as published on March 26, 2021 (86 *Federal Register* 16055), effective April 30, 2021~~.

~~(3) Pipeline quality natural gas--Natural gas containing no more than 0.25 grain of hydrogen sulfide and 5 grains of total sulfur per 100 dry standard cubic feet.~~

§112.212. Control Requirements.

~~(a) An owner or operator may not change the Regulated Entity Number (RN) or emission point number (EPN) designation of any source subject to §112.210 of this title (relating to Applicability) or otherwise contravene any of the control requirements in this section without the prior approval of the executive director and the United States Environmental Protection Agency (EPA).~~

(a) ~~(b) EPN FLR1 (~~Acid Gas Flare (EPN FLR1) and ~~EPN INCIN1 (~~Acid Gas Incinerator (EPN INCIN1) may not operate simultaneously.

(b) ~~(c) EPN FLR1 (~~Acid Gas Flare (EPN FLR1) emissions may not exceed 140.00

lb/hr sulfur dioxide (SO_2)~~SO_2~~.

(c) ~~(d) EPN INCIN1 (~~Acid Gas Incinerator (EPN INCIN1) emissions may not exceed 140.00 lb/hr SO_2.

(d) ~~(e)~~ The owner or operator may request an alternate means of control under the provisions of §112.232(k) of this title (relating to Control Requirements). ~~alternative SO_2 emission limit if dispersion modeling and analysis consistent with the most recent attainment demonstration confirms the alternative limit will not increase the modeled regulatory design value in the nonattainment area. The alternative limit and any deviations from the modeling methodology from the most recent attainment demonstration must be approved by the executive director and the EPA.~~

§112.213. Monitoring and Testing Requirements

(a) Monitoring requirements. The owner or operator shall continuously monitor, at a point prior to the manifold that directs gases to the Acid Gas Flare (EPN FLR1) or Acid Gas incinerator (EPN INCIN1), the gases routed to ~~EPN FLR1 (~~Acid Gas Flare (EPN FLR1) or ~~EPN INCIN1 (~~Acid Gas Incinerator (EPN INCIN1) by using the following:

(1) monitor at a point the sulfur content of the gas stream as follows: ~~an analyzer that is capable of accurately measuring and recording hydrogen sulfide levels to the range of 1 ppmv and that is installed prior to the manifold that directs gases to~~

~~EPN FLR1 or EPN INCIN1;~~

(A) using a separate dedicated analyzer capable of accurately measuring and recording total sulfur (including sulfur dioxide (SO_2), hydrogen sulfide (H_2S), and organic sulfur compounds levels) with an accuracy of ±5% on a continuous basis, the sulfur concentration must be determined in accordance 40 Code of Federal Regulations (CFR) §60.107a(e)(1) regardless of whether these requirements are otherwise applicable or exempt the flare or incinerator, and hourly SO_2 emissions must be determined using the following equation; or

Figure: 30 TAC §112.213(a)(1)(A)

$$SO_2 = Scc \times FFa \times \frac{Tsc}{Ta} \times \frac{Pa}{Psc} \times \frac{lb\ mole}{385.27\ scf} \times \frac{64.06\ lb\ SO_2}{lb\ mole}$$

Where:

SO_2 = Sulfur dioxide emissions in units of pounds per hour;

Scc = inlet sulfur compound concentration in cubic feet per 1,000,000 cubic feet of waste gas;

FFa = inlet waste gas stream flow in actual cubic feet per hour;

Psc = regulatory standard condition pressure of 14.7 pounds per square inch (psia);

Pa = FFa measurement pressure in units of psia;

Tsc = regulatory standard condition temperature of 528 degrees Rankin; and

Ta = inlet actual stream temperature in degrees Rankin

(B) using a separate dedicated analyzer capable of accurately measuring and recording H_2S to an accuracy of ±5% on a continuous basis, determine the H_2S concentration in the flared gas stream, derive an inlet flare or incinerator gas total sulfur concentration for each monitored hourly H_2S concentration in accordance 40 CFR §60.107a(e)(2) methodology regardless of whether these requirements are otherwise applicable or exempt the flare or incinerator, and calculate the SO_2 emissions from the flare and the incinerator for each operating hour that either is operated using the following equation:

Figure: 30 TAC §112.213(a)(1)(B)

$$SO_2 = H_2Smc \times \frac{Scc}{H_2Ssc} \times FFa \times \frac{Tsc}{Ta} \times \frac{Pa}{Psc} \times \frac{lb\ mole}{385.27\ scf} \times \frac{64.06\ lb\ SO_2}{lb\ mole}$$

Where:

SO_2 = Sulfur dioxide emissions in units of pounds per hour;

H_2Smc = monitored inlet hydrogen sulfide (H_2S) concentration in units of cubic feet of flare gas inlet stream sulfur compounds per 1,000,000 cubic feet of waste gas;

Scc = inlet sulfur compound concentration in units of cubic feet of waste gas inlet stream sulfur compounds per 1,000,000 cubic feet of flare gas derived in accordance with 40 CFR §60.107a(e)(2) methodology regardless of whether these requirements are otherwise applicable;

H_2Ssc = sampled H_2S concentration in units of cubic feet of waste gas inlet stream sulfur compounds per 1,000,000 cubic feet of flare gas;

FFa = inlet gas stream flow in units of actual cubic feet per hour;

Psc = regulatory standard condition pressure of 14.7 pounds per square inch (psia);

Pa = FFa measurement pressure in units of psia;

Tsc = regulatory standard condition temperature of 528 degrees Rankin; and

Ta = inlet stream actual temperature in degrees Rankin (the Tsc/Ta factor is used to convert FFa actual cubic feet to FFa standard cubic feet).

~~-~~(C) a totalizing gas flow meter with an accuracy of ±5% that is installed, calibrated, maintained, and operated according to per the manufacturer's specifications directions to continuously measure and record the volume of gas directed to the Acid Gas Flare (EPN FLR1) or Acid Gas Incinerator (EPN INCIN1); and

(D) monitor the temperature of gases routed to the flare or incinerator using a temperature measurement device with an accuracy of ±1%; the inlet flare gas temperature measurement device must be installed, calibrated, maintained, and operated according to the manufacturer's recommendations and specifications.

(2) In lieu of the monitoring requirements of §112.213(a)(1) of this subsection, the owner or operator may install, calibrate, and maintain a continuous emissions monitoring system to monitor exhaust SO_2 from the Acid Gas Incinerator (EPN INCIN1) in accordance with the requirements of 40 CFR §60.13, 40 CFR Part 60, Appendix B, Performance Specification 2 and 6, for SO_2, and 40 CFR Part 60, Appendix F, quality assurance procedures;

(3) ~~(3)~~ Continuous monitoring data collected in accordance with requirements in this subsection must undergo an appropriate quality assurance and

quality control process and be validated for at least 95% of the time that the monitored emission point has emissions; an owner or operator must utilize an appropriate data substitution process based on the most accurate methodology available, which is at least equivalent to engineering judgment, to obtain all missing or invalidated monitoring data for the remaining period the monitored emission point has emissions.

(4) Minor modifications to monitoring methods may be approved by the executive director. Monitoring methods other than those specified in this section may be used if approved by the executive director and validated by 40 CFR Part 63, Appendix A, Test Method 301. For the purposes of this subsection, substitute "executive director" in each place that Test Method 301 references "administrator." These validation procedures may be waived by the executive director or a different protocol may be granted for site-specific applications. Minor modifications that may be approved under this subsection include increases in the frequency of monitoring provided appropriate quality assurance control, accuracy specifications, and data validation requirements are specified and no less stringent than monitoring requirements for a comparable EPN in this subchapter.

(b) Testing requirements.

(1) The owner of operator shall perform initial testing for monitoring devices required by subsection (a) of this section if documentation is not available to demonstrate initial tests have been conducted, as well as all subsequent testing, in

accordance with the manufacturer's specifications to ensure that the required monitors are calibrated and function properly by the compliance date in §112.218 of this title (relating to Compliance Schedules).

(2) The owner or operator shall conduct initial performance testing by the compliance date in §112.218 of this title. During performance testing, the owner or operator shall operate the source at the maximum rated capacity, or as near thereto as practicable. The owner or operator shall conduct additional performance tests on the incinerator at least every five years after the compliance date to ensure the accuracy of the monitors for the gas stream sent to the incinerator or flare.

(3) The owner or operator shall conduct additional performance testing, if requested by the executive director, in compliance with 40 CFR §60.104a to demonstrate compliance with applicable emission limits or standards. The notification requirements of 40 CFR §60.8(d) apply to each initial performance test and to each subsequent performance test required by the executive director.

(4) All performance tests must be conducted using test methods allowed in §112.213(c).

(c) Approved test methods.

(1) Tests required under paragraph (b) of this section must be conducted

using the test methods in 40 CFR Part 60, Appendices A-1 through A-8 and Appendix B or other methods as specified in this section, except as provided in §60.8(b).

(2) Sulfur dioxide in exhaust gases from the incinerator during testing must be determined using United States Environmental Protection Agency (EPA) Test Method 6 or 6C (40 CFR, Part 60, Appendix A).

(3) Alternate test methods as approved by the executive director and the EPA may be used.

§112.216. Recordkeeping Requirements.

The owner or operator shall maintain records in written or electronic format for a minimum of five years of the continuous monitoring of the sulfur content and flow rate of gases routed to either the flare or the incinerator as well as which control device was in use and of all monitoring data and emission calculations required under §112.213 of this title (relating to Monitoring Requirements). The owner or operator shall maintain records for a minimum of five years of all testing done for monitors and copies of each performance test conducted. The owner or operator shall maintain documentation for a minimum of five years of any period that emission limits or standards were exceeded and copies of required exceedance reports submitted to the appropriate Texas Commission on Environmental Quality Regional Office.

§112.217. Reporting Requirements.

(a) For a source that is subject to an emissions limit in §112.212 of this title (relating to Control Requirements) and that exceeds an applicable emission limit or fails to meet a required stack parameter, the owner or shall submit to the Texas Commission on Environmental Quality (TCEQ) Regional Office for the area where the plant is located a report by March 31 of the year after an exceedance occurs documenting the excess emissions during the preceding calendar year, including at least the following:

(1) the date that each exceedance or failure to meet a required stack parameter occurred;

(2) an explanation of the exceedance or failure to meet a required stack parameter;

(3) a statement of whether the exceedance or failure to meet a required stack parameter was concurrent with a maintenance, startup, or ~~and~~ shutdown period for, or malfunction of, an affected source ~~facility~~ or control system;

(4) a description of the action taken, if any; and

(5) a written statement, signed by the owner or operator, certifying the

accuracy and completeness of the information contained in the report.

(b) The owner or operator shall submit a copy of each performance test report to the appropriate TCEQ regional office and any local air pollution control agency having jurisdiction for the area where the plant is located within 60 days after completion of the test.

(c) ~~(b)~~ After the effective date of a determination by the Environmental Protection Agency (EPA) that the Hutchinson County sulfur dioxide (SO_2) nonattainment area has failed to attain the 2010 one-hour SO_2 National Ambient Air Quality Standard or failed to meet reasonable further progress (RFP) pursuant to federal ~~Federal~~ Clean Air Act §179(c), 42 United States Code §7509(c), the TCEQ will notify the owner or operator of the failure to attain and that the contingency measures in this subsection are triggered. Once notification is received from the TCEQ, the owner or operator shall perform a full system audit (FSA) of all SO_2 sources subject to §112.210 of this title (relating to Applicability).

(1) Within 90 calendar days after the date of the notification, the owner or operator shall submit the FSA, including recommended provisional SO_2 emission control strategies as necessary, to the executive director of the TCEQ.

(2) As part of the FSA, the owner or operator shall conduct a root cause analysis of the circumstances surrounding the cause of the determination of failure to

attain or failure to meet RFP, including a review and consideration of the following:

(A) for all causes of the determination of failure to attain or failure to meet RFP, at a minimum, hourly mass emissions of SO_2 from each SO_2 source subject to this division; and

(B) for a determination of failure to attain based on ambient air monitor data or modeling data, at a minimum, the meteorological conditions recorded at the monitor or other relevant meteorological data, including the frequency distribution of wind direction temporally correlated with SO_2 readings greater than 75 parts per billion at the monitor for which the EPA's determination of failure to attain was made; and any emissions ~~exceptional~~ event that may have occurred. The root cause analysis and associated records used to conduct the audit must consider information on the days that monitored exceedances occurred during the time period that the EPA evaluated in making the failure to attain determination.

§112.218. Compliance Schedules.

The owner or operator of a source subject to §112.210 of this title (relating to Applicability) shall comply with the requirements of this division ~~as soon as practicable, but~~ no later than October ~~January~~ 1, 2023 ~~2025~~.

SUBCHAPTER F – REQUIREMENTS IN THE HUTCHINSON COUNTY NONATTAINMENT AREA

DIVISION 3 – REQUIREMENTS FOR THE ORION BORGER CARBON BLACK PLANT

§§112.220 - 112.228

Statutory Authority

The new sections are adopted under Texas Water Code (TWC), §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new sections are also adopted under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.014, concerning Emission Inventory, which authorizes the commission to require companies whose activities cause emissions of air contaminants to submit information to enable the commission to develop an inventory of emissions; THSC, §382.015, concerning Power to Enter Property, which authorizes a member, employee, or agent of

the commission to enter public or private property to inspect and investigate conditions relating to emissions of air contaminants; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants, as well as require recordkeeping; and THSC, §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe sampling methods and procedures to be used in determining violations of and procedures to be used in determining compliance.

The adopted new sections implement TWC, §5.103 and §5.105 and THSC, §§382.002, 382.011, 382.012, 382.015, 382.016, 382.017 and 382.021.

§112.220. Applicability.

(a) The requirements in this division apply to affected sources at the Orion Borger Carbon Black Plant, which is located at latitude 35.668055 and longitude -101.432777 ~~(Regulated Entity Number (RN) 100209659)~~ in the Hutchinson County sulfur dioxide ~~(SO_2)~~ nonattainment area. Affected sources will remain subject to this division regardless of ownership, operational control, or other documentation changes. ~~Once approved by the United States Environmental Protection Agency (EPA), the requirements in this division continue to apply until the EPA approves their removal.~~

(b) Affected existing sources are designated by source name and emission point number (EPN) used in the site's New Source Review (NSR) permit as issued on the specified date, except for one waste heat boiler that is designated by its source name and EPN in the applicable Pollution Control Project Standard Permit. Applicable control devices to be authorized and constructed are similarly designated by the EPN that the company used to designate the future unit in the attainment demonstration modeling, with an appropriate name also used in the rules. The specific affected sources are as follows:

(1) ~~EPN E-6BN,~~ Waste Heat Boiler – CDS Stack (EPN E-6BN)~~,~~ in the Final Action letter for Pollution Control Project Standard Permit 164021 dated March 3, 2021;

(2) ~~EPN E-10FL,~~ Unit 1 Reactor/Flare (EPN E-10FL)~~,~~ in NSR Permit 8780 dated March 24, 2015;

(3) ~~EPN E-20FL,~~ Unit 2 Reactor/Flare (EPN E-20FL)~~,~~ in NSR Permit 8780 dated March 24, 2015;

(4) ~~EPN E-40FL,~~ Unit 4 Reactor/Flare (EPN E-40FL)~~,~~ in NSR Permit 8780 dated March 24, 2015; and

(5) ~~EPN CFL,~~ Combined Flare (EPN CFL)~~,~~ if authorized and constructed.

§112.221. Definitions.

Unless specifically defined in the Texas Clean Air Act (Texas Health and Safety Code, Chapter 382), or in §101.1 or §112.1 of this title (relating to Definitions, respectively), the terms in this division have the meanings commonly used in the field of air pollution control. The following meanings apply in this division unless the context clearly indicates otherwise.

(1) Block one-hour average--An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the next clock hour (e.g., from 12:00:00 to 12:59:59).

(2) Continuous Monitoring--Monitoring for which readings are recorded at least once every 15 minutes.

(3) ~~(2)~~ Hutchinson County sulfur dioxide (SO_2) nonattainment area--The portion of Hutchinson County designated by the United States Environmental Protection Agency (EPA) as nonattainment for the 2010 SO_2 National Ambient Air Quality Standard, 40 Code of Federal Regulations §81.344~~, as published on March 26, 2021 (86 *Federal Register* 16055), effective April 30, 2021~~.

~~(3) Pipeline quality natural gas--Natural gas containing no more than 0.25 grain of hydrogen sulfide and 5 grains of total sulfur per 100 dry standard cubic feet.~~

(4) Production unit--the carbon black oil furnace or group of carbon black oil furnaces, dryers or groups of dryers, and any ancillary units used in the manufacture of carbon black and producing tail gas.

(5) Tail gas--The exit gaseous stream of a carbon black oil furnace consisting of water vapor, carbon monoxide, hydrogen, pyrolysis by-products, and reduced and organic sulfur compounds as a result of the manufacture of carbon black.

§112.222. Control Requirements.

~~(a) The owner or operator may not change the Regulated Entity Number (RN) or emission point number (EPN) designation of any source subject to §112.220 of this title (relating to Applicability) or otherwise contravene any of the control requirements in this section without the prior approval of the executive director and the United States Environmental Protection Agency (EPA).~~

(a) ~~(b)~~ Hourly mass emissions of sulfur dioxide (SO_2), on a block one-hour average, may not exceed the following:

(1) 144.11 lb/hr SO_2, for the ~~EPN E-6BN (~~Waste Heat Boiler – CDS Stack (EPN E-6BN); and

(2) 750.05 lb/hr SO_2, for the ~~EPN CFL (~~Combined Flare (EPN CFL).

(b) ~~(c)~~ Tail gas may only be combusted in a source whose emissions are routed to Waste Heat Boiler – CDS Stack (EPN E-6BN) ~~(Waste Heat Boiler – CDS Stack)~~ or Combined Flare (EPN CFL) ~~(Combined Flare)~~.

(c) ~~(d)~~ The Unit 1 Reactor/Flare Unit 1 Reactor/Flare (EPN E-10FL)~~-~~, Unit 2 Reactor/Flare (EPN E-20FL) ~~(Unit 2 Reactor/Flare)~~, and Unit 4 Reactor/Flare (EPN E-40FL) ~~(Unit 4 Reactor/Flare)~~ may not operate on or after the compliance date in §112.228 of this title (relating to Compliance Schedules).

(d) ~~(e)~~ If the Combined Flare (EPN CFL) ~~(Combined Flare)~~ is not authorized and constructed by the compliance date in §112.228 of this title, no flaring is allowed until EPN CFL is authorized, constructed, and operating.

(e) ~~(f)~~ After construction and commencement of operation, the ~~EPN CFL (~~Combined Flare (EPN CFL) must meet the following parameters:

~~(1) receive all waste gases instead of the existing EPN E-10FL, EPN E-20FL, and EPN E-40FL;~~

(1) ~~(2)~~ only receive tail gas when Waste Heat Boiler – CDS Stack (EPN E-6BN) ~~(Waste Heat Boiler – CDS Stack)~~ is not operating; and

(2) ~~(3)~~ be constructed with a stack height of ~~no less than~~ 65.00 meters and must be located at Universal Transverse Mercator (UTM) coordinates UTM East Meters 279745.85 and UTM North Meters 3949549.50 in UTM Zone 14.

(f) ~~(g)~~ The owner or operator may request an alternate means of control under the provisions of §112.232(k) of this title (relating to Control Requirements). ~~alternative SO_2 emission limit if dispersion modeling and analysis consistent with the most recent attainment demonstration confirms the alternative limit will not increase the modeled regulatory design value in the nonattainment area. The alternative limit and any deviations from the modeling methodology from the most recent attainment demonstration must be approved by the executive director and the EPA.~~

§112.223. Monitoring Requirements.

(a) The owner or operator shall install ~~Install~~, calibrate, and maintain a continuous emissions monitoring system (CEMS) to continuously monitor the exhaust sulfur dioxide (SO_2) emissions ~~SO_2~~ from ~~EPN E-6BN (~~Waste Heat Boiler – CDS Stack (EPN E-6BN) in accordance with the requirements of 40 Code of Federal Regulations (CFR) §60.13, 40 CFR Part 60, Appendix B, Performance Specification 2 and 6, for SO_2, and 40 CFR Part 60, Appendix F, quality assurance procedures. ~~Part 60 as follows~~

~~(1) §60.13;~~

~~(2) Appendix B, Performance Specification 2, for SO_2; and~~

~~(3) Appendix F, quality assurance procedures.~~

(b) For days when EPN CFL (Combined Flare) is used to combust tail gas, the owner or operator shall monitor the sulfur content of the carbon black oil feedstock and produced carbon black, as well as the production rate of the carbon black, as follows:

(1) measure twice per day at least four hours apart ~~daily~~ the sulfur content by weight of the carbon black oil in the feed to each production unit according to the requirements of §112.225 of this title (relating to Approved Test Methods);

(2) unless the sulfur content of the carbon black produced is assumed to be zero in the calculation of SO_2 emissions from the flare, for each grade of carbon black produced, measure daily the sulfur content by weight of the carbon black produced by each carbon black production unit according to the requirements of §112.225 of this title; and

(3) determine hourly the amount of each grade of carbon black produced by each carbon black production unit.

(c) The owner or operator shall install, calibrate, maintain, and operate one or more totalizing fuel flow meters, with an accuracy of ± 5%, to continuously measure the feed rate of carbon black oil feedstock supplied to each carbon black production unit.

(d) The owner or operator shall install ~~Install~~, calibrate, maintain, and operate totalizing tail gas flow meters, with an accuracy of ± 5%, to continuously measure the volumetric flow rate of tail gas to EPN CFL (Combined Flare).

(e) Continuous monitoring data collected in accordance with requirements in this subsection must undergo an appropriate quality assurance and quality control process and be validated for at least 95% of the time that the monitored emission point has emissions; an owner or operator must utilize an appropriate data substitution process based on the most accurate methodology available, which is at least equivalent to engineering judgement, to obtain all missing or invalidated monitoring data for the remaining period the monitored emission point has emissions.

(f) The owner or operator shall calculate ~~Calculate total~~ SO_2 emissions from EPN CFL (Combined Flare) from all production units using the equation below ~~in subsection (h) of this section, which assumes that all the sulfur in the carbon black oil feedstock that is not accounted for by sulfur in the carbon black product, is converted to~~ ~~SO_2~~ to demonstrate compliance with the emission requirements of §112.222 of this title (relating to Control Requirements).

Figure: 30 TAC §112.223(f)

$$SO_{2,CFL} = \sum_{i=1}^{\tau} \sigma_i$$

Where:

$SO_{2,CFL}$= Emissions of sulfur dioxide (SO_2) expressed in units of pounds per hour (lb/hr) from EPN CFL;

i= the carbon black production unit;

τ = the number of carbon black production units contributing carbon black oil furnace tail gas to EPN CFL; and

σ_i = emissions of SO_2 expressed in units of lb/hr calculated by §112.223(h) of this section generated by each production unit.

(g) Emissions ~~Actual emissions~~ of SO_2 from each EPN specified under §112.222 of this title ~~for each operational scenario occurring~~ during any block one-hour period must be calculated on a block one-hour average.

(h) The owner or operator shall calculate ~~Calculate total~~ SO_2 emissions generated by ~~from~~ each production unit using the following equation.

Figure: 30 TAC §112.223(h)

$$\sigma_i = [(S_{oil} \times D_{oil} \times F_{oil}) - (S_p \times P_p)] \times 2$$

Where:

σ_i = emissions of sulfur dioxide generated by each production unit in units of pounds per hour;

i = the carbon black production unit;

S_{oil} = weight of sulfur in carbon black oil in units of pounds of sulfur per pound of carbon black oil;

D_{oil} = density of carbon black oil in pounds per gallon determined at a temperature consistent with the carbon black oil feed;

F_{oil} = feed rate of oil to carbon black production unit in gallons per hour;

S_p = sulfur content of carbon black product as determined in units of pound of sulfur per pound of product;

P_p = production rate of carbon black product in units of pounds per hour; and

2 = the molecular weight ratio of SO_2 to sulfur.

$$\cancel{SO_2 = (SI - SRB) \times 2}$$

~~Where:~~

~~SO_2 = mass emissions of SO_2, expressed in units of lb/hr;~~

~~SI = the sulfur input from the carbon black oil feedstock determined by sampling as required by §112.223(2)(A);~~

~~SRB = the sulfur retained in the produced carbon black determined by sampling as required by §112.223(c)(B);~~

~~2 = the molecular weight ratio of SO_2 to sulfur.~~

(i) Minor modifications to monitoring methods may be approved by the executive director. Monitoring methods other than those specified in this section may be used if approved by the executive director and validated by 40 CFR Part 63, Appendix A, Test Method 301. For the purposes of this subsection, substitute "executive director" in each place that Test Method 301 references "administrator." These validation procedures may be waived by the executive director or a different protocol may be granted for site-specific applications. Minor modifications that may be approved under this subsection include increases in the frequency of monitoring and the replacement of parametric monitoring with direct emissions monitoring with a CEMS provided appropriate quality assurance control, accuracy specifications, and data validation requirements are specified and no less stringent than monitoring requirements for a comparable EPN in this division.

§112.224. Testing Requirements.

(a) During performance ~~stack~~ testing, the owner or operator shall operate the source ~~facility~~ at the maximum rated capacity, or as near thereto as practicable.

(b) The owner or operator shall conduct additional performance testing requested by the executive director using test methods allowed in §112.225 of this title (relating to Approved Test Methods).

(c) When analysis of produced carbon black, carbon black oil, and fuels, including but not limited to tail gas, is required for monitoring under §112.223 of this title (relating to Monitoring Requirements), the owner or operator shall use a test method in §112.225 of this title for the analysis.

§112.225. Approved Test Methods.

(a) Tests required under §112.224 of this title (relating to Testing Requirements) must be conducted using the test methods in 40 Code of Federal Regulations (CFR) Part 60, Appendices A-1 through A-8 and Appendix B or other methods as specified in this section, except as provided in 40 CFR §60.8(b) ~~(*36 Federal Register* (FR) 24877, published Dec. 23, 1971, as amended through 81 FR 59809, published Aug. 30, 2016)~~.

(b) Sulfur dioxide ~~(SO_2)~~ in exhaust gases must be determined using United States Environmental Protection Agency (EPA) Test Method 6 or 6C (40 CFR, Part 60, Appendix A).

(c) For flares subject to emissions limitations or standards in §112.222 of this title (relating to Control Requirements), the owner or operator shall use flare test methods and procedures in 40 CFR §60.104a ~~(73 FR 35867, published June 24, 2008 as amended 77 FR 56470, published September 12, 2012 and 80 FR 75231, published December 1, 2015)~~ as if the federal rules apply to carbon black plants.

(d) Sulfur content of fuels and carbon black oil must be determined using American Society for Testing and Materials (ASTM) Method D4294 ~~D1945-91 or ASTM Method D3588-93~~ for fuel composition.

(e) Sulfur content of carbon black must be determined using ASTM Test Method D1619.

(f) Alternate test methods as approved by the executive director and the EPA may be used.

§112.226. Recordkeeping Requirements.

The owner or operator shall maintain records in written or electronic format sufficient to demonstrate compliance with each applicable requirement for a minimum of five years, including but not limited to the following:

(1) records in units of pounds per hour (lb/hr) of production of carbon black for each grade of carbon black from each carbon black production unit;

(2) daily records of sulfur content by weight of the carbon black oil feedstock;

(3) daily records of sulfur content by weight of the carbon black produced for each grade of carbon black produced by each carbon black production unit;

(4) records of continuous carbon black oil feedstock flow rates for each carbon black production unit;

(5) records of continuous tail gas volumetric flow rates to each tail gas combustion device covered by §112.222 of this title (relating to Control Requirements);

(6) for each block one-hour period of operation of a carbon black production unit, the required mass balance calculations of emissions of sulfur dioxide (SO_2) ~~SO_2~~ from each emission point number (EPN) for those sources in operation without a continuous emissions monitoring system for ~~sulfur dioxide (~~SO_2~~)~~;

(7) the continuous SO_2 emissions monitoring data ~~of emissions of SO_2~~ for each EPN ~~for those sources~~ in operation with a CEMS for SO_2; ~~and~~

(8) documentation of any period that emission limits or standards were exceeded, and copies of exceedance reports submitted to the appropriate Texas Commission on Environmental Quality regional office; and ~~copies of required emission test data and records.~~

(9) copies of test reports for tests conducted in accordance with §112.225 and associated records.

§112.227. Reporting Requirements.

(a) For a source that is subject to an emissions limit in §112.222 of this title (relating to Control Requirements) and that exceeds an applicable emission limit or fails to meet a required stack parameter, the owner or operator shall submit to the Texas Commission on Environmental Quality (TCEQ) Regional Office for the area where the plant is located a report by March 31 of the year after an exceedance occurs documenting the excess emissions during the preceding calendar year, including at least the following:

(1) the date that each exceedance or failure to meet a required stack parameter occurred;

(2) an explanation of the exceedance or failure to meet a required stack parameter;

(3) a statement of whether the exceedance or failure to meet a required stack parameter was concurrent with a maintenance, startup, or ~~and~~ shutdown period for, or malfunction of, an affected source ~~facility~~ or control system;

(4) a description of the action taken, if any; and

(5) a written statement, signed by the owner or operator, certifying the accuracy and completeness of the information contained in the report.

(b) The owner or operator shall submit a copy of each performance ~~stack~~ test report to the TCEQ Regional Office and any local air pollution control agency having jurisdiction for the area where the plant is located within 60 days after completion of the test.

(c) After the effective date of a determination by the Environmental Protection Agency (EPA) that the Hutchinson County sulfur dioxide (SO_2) nonattainment area has failed to attain the 2010 one-hour SO_2 National Ambient Air Quality Standard or failed to meet reasonable further progress (RFP) pursuant to Federal Clean Air Act §179(c), 42 United States Code §7509(c), the TCEQ will notify the owner or operator of the failure to attain and that the contingency measures in this subsection are triggered. Once notification is received from the TCEQ, the owner or operator shall perform a full system audit (FSA) of all SO_2 sources subject to §112.220 of this title (related to Applicability).

(1) Within 90 calendar days after the date of the notification, the owner or operator shall submit the FSA, including recommended provisional SO_2 emission control strategies as necessary, to the executive director of the TCEQ.

(2) As part of the FSA, the owner or operator ~~of each company~~ shall conduct a root cause analysis of the circumstances surrounding the cause of the determination of failure to attain or failure to meet RFP, including a review and consideration of the following:

(A) for all causes of the determination of failure to attain or failure to meet RFP, at a minimum, hourly mass emissions of SO_2 from each SO_2 source subject to this division; and

(B) for a determination of failure to attain based on ambient air monitor data or modeling data, at a minimum, the meteorological conditions recorded at the monitor or other relevant meteorological data, including the frequency distribution of wind direction temporally correlated with SO_2 readings greater than 75 parts per billion at the monitor for which the EPA's determination of failure to attain was made; and any emissions ~~exceptional~~ event that may have occurred. The root cause analysis and associated records used to conduct the audit must consider information on the days that monitored exceedances occurred during the time period that the EPA evaluated in making the failure to attain determination.

§112.228. Compliance Schedules.

(a) The owner or operator of a source subject to §112.220 of this title (relating to Applicability) shall comply with the requirements of this division no later than June 30, 2023, except for §112.222(a)(2), (b) - (e), §112.223(b), (d), (f), (h), and §112.226(1) - (6).

(b) The owner or operator of a source subject to §112.220 of this title~~(Applicability)~~ shall comply with §112.222(a)(2), (b) - (e), §112.223(b), (d), (f), (h), and §112.226(1) - (6) ~~the requirements of this division as soon as practicable, but~~ no later than January 1, 2025.

SUBCHAPTER F – REQUIREMENTS IN THE HUTCHINSON COUNTY NONATTAINMENT AREA

DIVISION 4 – REQUIREMENTS FOR THE PHILLIPS 66 BORGER REFINERY

§§112.230 - 112.238

Statutory Authority

The new sections are adopted under Texas Water Code (TWC), §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new sections are also adopted under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.014, concerning Emission Inventory, which authorizes the commission to require companies whose activities cause emissions of air contaminants to submit information to enable the commission to develop an inventory of emissions; THSC, §382.015, concerning Power to Enter Property, which authorizes a member, employee, or agent of

the commission to enter public or private property to inspect and investigate conditions relating to emissions of air contaminants; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants, as well as require recordkeeping; and THSC, §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe sampling methods and procedures to be used in determining violations of and procedures to be used in determining compliance.

The adopted new sections implement TWC, §5.103 and §5.105 and THSC, §§382.002, 382.011, 382.012, 382.015, 382.016, 382.017 and 382.021.

§112.230. Applicability.

(a) The requirements in this division apply to affected sources at the Phillips 66 Refinery, which is located in Borger, Texas at coordinates latitude 35.700000 and longitude -101.366666 ~~(Regulated Entity Number (RN) 102495884)~~ in the Hutchinson County sulfur dioxide ~~(SO_2)~~ nonattainment area. Affected sources will remain subject to this division regardless of ownership, operational control, or other documentation changes. ~~Once approved by the United States Environmental Protection Agency (EPA), the requirements in this division continue to apply until the EPA approves their removal.~~

(b) Affected existing sources are designated by the source name (when possible) and emission point number (EPN) ~~and source name (when possible)~~ used in the site's New Source Review (NSR) permit as issued on the specified date. The specific affected sources are as follows:

(1) ~~EPN 29P1,~~ Unit 29 FCCU Stack (EPN 29P1)~~,~~ in NSR Permit 9868A dated September 17, 2021;

(2) ~~EPN 40P1,~~ Unit 40 FCCU Stack (EPN 40P1)~~,~~ in NSR Permit 9868A dated September 17, 2021;

(3) ~~EPN 34I1,~~ SRU Incinerator (EPN 34I1)~~,~~ in NSR Permit 9868A dated September 17, 2021;

(4) ~~EPN 43I1,~~ SCOT Unit Incinerator (EPN 43I1)~~,~~ in NSR Permit 9868A dated September 17, 2021 (emissions from this source during authorized maintenance, startup, and shutdown activities are included as EPN SRU_MS_CAP in the attainment demonstration modeling);

(5) EPN 66FL1, EPN 66FL2, EPN 66FL3, and EPN 66FL12 in NSR Permit 80799 dated October 1, 2020 (emissions from these sources are included as EPN FLARE_R_CAP and EPN FLARE_MS_CAP in the attainment demonstration modeling);

(6) EPN 12E1, EPN 12E2, EPN 12E3, EPN 12E4, EPN 12E5, EPN 12E6, EPN 12E7, EPN 7E1, EPN 7E2, EPN 7E3, EPN 7E4, EPN 7E5, EPN 7E6, EPN 10H1, EPN 19B1/19H1, EPN 19B1/19H2, EPN 19H3, EPN 19B2/19H4, EPN 19H5, EPN 19H6, EPN 2H1, EPN 2H2, EPN 22H1, EPN 26H1, EPN 28H1, EPN 29H4, EPN 34I1, EPN 36H1, EPN 40H1, EPN 4H2, EPN 42H1, EPN 42H2, EPN 43I1, EPN 50H1, EPN 5H1, EPN 6H1, EPN 7H1-4, EPN 9H1, EPN 93E1, EPN 93E2, EPN 98H1, EPN 51H1, EPN 4H1, EPN 6H3, EPN 12H1, ~~EPN 66FL13~~ and EPN 41H1 in NSR Permit 9868A dated September 17, 2021 (these sources included as EPN FLEX_R_CAP in the attainment demonstration modeling); and

(7) EPN 12E1, EPN 12E2, EPN 12E3, EPN 12E4, EPN 12E5, EPN 12E6, EPN 12E7, EPN 7E1, EPN 7E2, EPN 7E3, EPN 7E4, EPN 7E5, EPN 7E6, EPN 10H1, EPN 19B1/19H1, EPN 19B1/19H2, EPN 19H3, EPN 19B2/19H4, EPN 19H5, EPN 19H6, EPN 2H1, EPN 2H2, EPN 22H1, EPN 26H1, EPN 28H1, EPN 29H4, EPN 36H1, EPN 40H1, EPN 4H2, EPN 42H1, EPN 42H2, EPN 50H1, EPN 5H1, EPN 6H1, EPN 7H1-4, EPN 9H1, EPN 93E1, EPN 93E2, EPN 98H1, EPN 51H1, EPN 4H1, EPN 6H3, EPN 12H1, ~~EPN 66FL13~~ and EPN 41H1, in NSR Permit 9868A dated September 17, 2021 (these sources are included as EPN FLEX_MS_CAP in the attainment demonstration modeling).

§112.231. Definitions.

Unless specifically defined in the Texas Clean Air Act (Texas Health and Safety Code, Chapter 382), or in §101.1 or §112.1 of this title (relating to Definitions, respectively), the terms in this division have the meanings commonly used in the field of air pollution control. The following meanings apply in this division unless the context clearly indicates otherwise.

(1) Block one-hour average--An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the next clock hour (e.g., from 12:00:00 to 12:59:59).

(2) Continuous Monitoring— Monitoring for which readings are recorded at least once every 15 minutes.

(3) ~~(2)~~ Hutchinson County sulfur dioxide (SO_2) nonattainment area--The portion of Hutchinson County designated by the United States Environmental Protection Agency (EPA) as nonattainment for the 2010 SO_2 National Ambient Air Quality Standard, 40 Code of Federal Regulations §81.344~~, as published on March 26, 2021 (86 *Federal Register* 16055), effective April 30, 2021~~.

(4) ~~(3)~~ Pipeline quality natural gas--Natural gas containing no more than 0.25 grain of hydrogen sulfide and 5 grains of total sulfur per 100 dry standard cubic feet.

§112.232. Control Requirements.

~~(a) The owner or operator may not change the Regulated Entity Number (RN) or emission point number (EPN) designation of any source subject to §112.230 of title (relating to Applicability) or otherwise contravene any of the control requirements in this section without the prior approval of the executive director and the United States Environmental Protection Agency (EPA).~~

(a) ~~(b)~~) ~~EPN 34I1 (~~SRU Incinerator (EPN 34I1) emissions may not exceed 44.82 pounds per hour (lb/hr) sulfur dioxide (SO_2) during normal operations;

(b) ~~(c) EPN 43I1 (~~SCOT Unit Incinerator (EPN 43I1) emissions may not exceed 37.00 lb/hr SO_2 during normal operations.

(c) ~~(d)~~ During authorized maintenance, startup, and shutdown (MSS) activities, ~~EPN 34I1 (~~SRU Incinerator (EPN 34I1) and ~~EPN 43I1 (~~SCOT Unit Incinerator (EPN 43I1) may not operate simultaneously and the combined emissions from these sources may not exceed 94.00 lb/hr SO_2

(d) ~~(e)~~ EPN 66FL1, EPN 66FL2, EPN 66FL3, and EPN 66FL12, ~~and EPN 66FL13~~ may only combust pipeline quality natural gas or a refinery gas stream with a maximum sulfur content of 162 parts per million by volume as hydrogen sulfide determined hourly on a three-hour rolling average basis except as provided for in 40 CFR §60.103a(h).

(e) ~~(f)~~ The combined emissions from EPN 66FL1, EPN 66FL2, EPN 66FL3, and EPN 66FL12 may not exceed 100.14 lb/hr SO_2 during normal operations and 850.00 lb/hr SO_2 during authorized MSS activities.

(f) ~~(g)~~ The combined emissions from EPNs listed in §112.230(b)(6) of this title may not exceed 172.09 ~~185.69~~ lb/hr SO_2 during normal operations.

(g) ~~(h)~~ The combined emissions from EPNs listed in §112.230(b)(7) of this title may not exceed 92.45 ~~106.05~~ lb/hr SO_2 during authorized MSS activities.

(h) ~~(i) EPN 29P1 (~~Unit 29 FCCU Stack (EPN 29P1) emissions may not exceed 97.37 lb/hr SO_2 on a seven-day rolling average. ~~the following:~~

~~(1) 155.49 lb/hr SO_2 during normal operations;~~

~~(2) 155.49 lb/hr SO_2 during authorized MSS activities with an exhaust flow rate greater than or equal to 210,922.60 actual cubic meters/hour (am^3/hr);~~

~~(3) 140.00 lb/hr SO_2 during authorized MSS activities with an exhaust flow rate greater than or equal to 158,191.95 am^3/hr and less than 210,922.60 am^3/hr;~~

~~(4) 130.00 lb/hr SO_2 during authorized MSS activities with an exhaust flow rate greater than or equal to 105,461.30 am^3/hr and less than 158,191.95 am^3/hr;~~

~~and~~

~~(5) exhaust flow rates below 105,461.30 am³/hr are prohibited.~~

(i) ~~(j)~~ EPN 40P1 (Unit 40 FCCU Stack (EPN 40P1) emissions may not exceed 101.37 lb/hr SO_2 on a seven-day rolling average. ~~the following:~~

~~(1) 155.49 lb/hr SO_2 during normal operations;~~

~~(2) 155.49 lb/hr SO_2 during authorized MSS activities with an exhaust flow rate greater than or equal to 298,242.71 am³/hr;~~

~~(3) 140.00 lb/hr SO_2 during authorized MSS activities with an exhaust flow rate greater than or equal to 223,682.03 am³/hr and less than 298,242.71 am³/hr;~~

~~(4) 130.00 lb/hr SO_2 during authorized MSS activities with an exhaust flow rate greater than or equal to 149,121.36 am³/hr and less than 223,682.03 am³/hr; and~~

~~(5) exhaust flow rates below 149,121.36 am³/hr are prohibited.~~

(j) ~~(k)~~ Unless otherwise specified, compliance ~~Compliance~~ with the emission limits in this section must be calculated on a block one-hour average basis.

(k) ~~(l)~~ The owner or operator may request an alternate means of control (AMOC) as follows. ~~alternative SO_2 emission limit if dispersion modeling and analysis consistent with the most recent attainment demonstration confirms the alternative limit will not increase the modeled regulatory design value in the nonattainment area. The alternative limit and any deviations from the modeling methodology from the most recent attainment demonstration must be approved by the executive director and the EPA~~.

(1) Permitting Requirements. Compliance with this subsection does not relieve any owner or operator of the responsibility to comply with the requirements of §116.110 or §116.151 of this title (relating to Applicability and New Major Source or Major Modification in Nonattainment Area Other Than Ozone, respectively) with respect to the new construction or modification of sources that may emit SO_2 into the air of this state.

(2) Availability of AMOC.

(A) The owner or operator of any site subject to a control requirement in this subchapter may request approval of an AMOC plan using the procedures established in this subsection. The executive director shall review a submitted AMOC and may approve the AMOC plan if it is demonstrated that the plan meets all applicable criteria and procedures of this subsection. The owner or operator who submits an AMOC plan not satisfying the requirements of this section may apply for a site-specific state implementation plan revision approved by the executive director and the United States Environmental Protection Agency (EPA).

(B) An AMOC applicant may apply to the executive director for a waiver of portions of paragraphs (5) and (6) of this subsection.

(C) Application for an AMOC plan does not stay enforcement of regulations in this subchapter.

(D) Any violation of an AMOC plan will be subject to enforcement action as a violation of this subchapter.

(3) Criteria for Approval of AMOC Plans. An AMOC plan may be approved if it meets each of the following criteria, as applicable.

(A) Except as provided for in paragraph (8) of this subsection, all sources covered by the AMOC plan must be and remain at the same site.

(B) If the AMOC plan includes an increase in the lb/hr emission limit for a source subject to the control requirements in this subchapter, the AMOC plan must also include an equivalent decrease in the lb/hr emission limit for one or more sources subject to the control of this subchapter.

(C) The AMOC application must include a demonstration that satisfies the following requirements.

(i) The modeled impacts of all sources affected by the AMOC plan demonstrate no net increase in ground-level concentration, which for purposes of this subparagraph means no net increase in modeled off-property concentration of SO_2, on a highest, first-high basis, at any receptor, *i,* in excess of the lesser of:

(I) $GLC_{crit,i}$, as defined in the following equation; or

Figure 30 TAC §112.232(k)(3)(C)(i)(I)

$$GLC_{crit,i} = 0.5 \times (196.4\ {}^{\mu g}/_{m^3} - DV_{AD,i}) - \left(DV - DV_{AD,i}\right)$$

Where:

$GLC_{crit,i}$ = The value for each receptor *i* that the modeled concentration in an AMOC demonstration cannot exceed.

$DV_{AD,i}$ = The maximum design value in any modeled scenario approved by the Environmental Protection Agency under 40 Code of Federal Regulations §51.112(a) for receptor *i*; and

DV = The design value specified by the Executive Director under this section, which, on the effective date of this section, equals DVA_o; and may subsequently be no less than DVA_o.

DVA_o = The design value based on the attainment demonstration modeling for the Hutchinson County SO_2 nonattainment area.

(II) an applicable significant impact level for the one-hour National Ambient Air Quality Standard for SO_2.

(ii) Except where otherwise provided in this section, the demonstration required under this paragraph must be by means of applicable air quality models, databases, and other requirements specified in Appendix W to 40 CFR §51.1 and what was used in the modeling for the corresponding SIP revision.

(D) The AMOC must be implemented and reductions created after the effective date of this rule.

(E) The AMOC plan must establish control requirements and monitoring, testing, recordkeeping and reporting requirements consistent with and no less stringent than the applicable requirements of this subchapter for all sources in the plan that render the proposed control requirements enforceable.

(4) Procedures for AMOC Plan Submittal.

(A) The owner or operator requesting an AMOC plan shall submit a proposed AMOC plan and demonstration to the executive director; copies of such plan and demonstration must also be submitted to the appropriate regional office, any local air pollution control program with jurisdiction over the site affected by the AMOC plan, and to the EPA regional office.

(B) The proposed AMOC plan must include the following information:

(i) the AMOC applicant name with mailing address, site name with physical address, regulated entity number, and contact person including address and telephone number;

(ii) an identification and a description of the sources involved in the AMOC plan including any applicable air permit numbers, plot plans, detailed flow diagrams, emission point numbers (EPNs), and facility identification numbers (FINs); an identification of the provisions of this subchapter that are applicable to such sources; and an identification of promulgated provisions of this subchapter that will be applicable to such sources; and a description of normal operating conditions for each source causing emissions;

(iii) control requirements, which must be established for each source to make emission limits enforceable, to be applicable to each source affected by the proposed AMOC plan;

(iv) a demonstration that the AMOC plan satisfies each applicable requirement of paragraph (3) of this subsection;

(v) a list containing the name, address, and telephone number of any air pollution control program with jurisdiction over the site affected by the AMOC plan; and

(vi) any other relevant information necessary to evaluate the merits and enforceability of the AMOC plan, as may be requested by the executive director.

(C) All representations with regard to the AMOC plan, as well as any provisions attached to the AMOC plan, become conditions upon which the subsequent AMOC plan is issued. If the AMOC plan is approved by the executive director and the EPA, the owner or operator may not vary from such representation or provision if the change will cause a change in the method of control of emissions, the character of the emissions, or will result in an increase in the discharge of the various emissions. If the AMOC plan is approved by the executive director and the EPA, the owner or operator may not vary from the emission limits, control requirements, monitoring, testing, reporting, or recordkeeping requirements of an approved AMOC plan.

(D) Applications to amend or revise an AMOC plan must be submitted subject to the requirements of this subsection.

(5) Procedures for an AMOC Plan Approval. Upon a preliminary determination to approve or deny the proposed AMOC plan, the executive director shall, in writing, so notify the submitter of the plan, any local air pollution control program with jurisdiction over the site affected by the AMOC plan, and the EPA regional office.

(A) If the executive director makes a preliminary determination to approve the AMOC plan, the notice must include a copy of the AMOC plan as preliminarily approved.

(B) If the executive director makes a determination to deny the AMOC plan, the notice must include a description of the reasons for such determination of denial. This determination constitutes a final action of the executive director appealable to the Commission as provided in paragraph (7) of this subsection.

(C) Upon receipt of notice from the executive director that the AMOC plan has received preliminary approval, the AMOC applicant, at the applicant's own expense, shall cause notice of the applicant's intent to obtain an AMOC plan and of the opportunity to submit written comments to be published. The notice must be consistent with paragraph (6) of this subsection.

(D) The executive director shall consider and prepare a written response to all significant and timely written comments filed in connection with an

AMOC plan.

(E) In response to the written comments, the executive director may modify the provisions of the AMOC plan, deny the AMOC plan, or approve the AMOC plan without changes.

(F) The executive director shall send written notice of the final determination concerning each AMOC plan to the submitter of the plan, the EPA regional office, any local pollution control program with jurisdiction, and to each person who submitted timely written comments. Such notice must include the final AMOC plan provisions, a copy of the response to comments, and an announcement of the opportunity to appeal the executive director's determination to the Commission. The notice required by this subparagraph must be sent by a means evidencing receipt.

(G) Any person entitled to notice under paragraph (6) of this subsection may, within 15 days of the receipt of such notice, file with the executive director an appeal of the final determination on the AMOC plan. Such appeal may be considered at the next regularly scheduled meeting of the Commission for which adequate notice may be made. Based on arguments submitted to the commission during such appeal, the Commission may remand the AMOC determination to the executive director, deny the AMOC plan, or issue the AMOC plan unchanged.

(H) Within 45 days of final approval of the AMOC plan by the executive director or the Commission for an appeal, the EPA may notify the commission of the EPA's disapproval of the executive director's final decision. Such notification must be in writing and must include a statement of the reason(s) for the disapproval and a specific listing of changes to the AMOC plan needed to overcome the disapproval. Any time prior to the expiration of the 45-day period, the EPA may notify the executive director that no disapproval is forthcoming. Upon receipt of a timely EPA disapproval, the executive director shall void or revise the AMOC plan and reissue the notice as required by paragraph (6) of this subsection.

(I) If no appeal of the executive director's decision to approve the AMOC plan is filed pursuant to subparagraph (G) of this paragraph, the AMOC plan becomes effective upon the acceptance of the plan by the EPA as described in subparagraph (K) of this paragraph.

(J) If an appeal of the executive director's decision is filed, the AMOC plan becomes effective upon the latter of the acceptance of the AMOC plan by the Commission or the acceptance of the AMOC plan by the EPA.

(K) EPA acceptance is defined as explicit approval of the AMOC plan by the EPA, notification by the EPA to the executive director that no EPA disapproval is forthcoming, or failure of the EPA to file notice of disapproval within 45 days after the executive director's final decision to approve the AMOC plan.

(6) Public Notice Format.

(A) Public notice must be published in the public notice section of two successive issues of a newspaper of general circulation in or closest to the municipality in which the site affected by the AMOC plan is located.

(B) Public notice must contain the following information:

(i) the AMOC plan application number assigned by the executive director;

(ii) the AMOC applicant’s name;

(iii) the type of source and site;

(iv) a description of the location of the site;

(v) a brief description of the AMOC plan;

(vi) the executive director's preliminary determination to approve the plan;

(vii) the locations and availability of copies of the proposed

AMOC plan, related documentation, and the executive director's preliminary analysis of the plan (including the Austin and appropriate regional offices, any local pollution control program with jurisdiction over the site affected by the AMOC plan, and the EPA regional office);

(viii) an announcement of the opportunity to submit written comments on the AMOC plan;

(ix) the length of the public comment period, which extends to at least 30 days after the final publication of the notice;

(x) the procedure for submission of written public comments concerning the proposed AMOC plan; and

(xi) the name, address, and phone number of the Agency’s regional office to be contacted for further information.

(C) The executive director may not take final action on the AMOC plan until the owner or operator who submitted the AMOC plan has provided proof of adequate notice to the executive director, the EPA, and any local pollution control program with jurisdiction.

(7) Review of Approved AMOC Plans and Termination of AMOC Plans.

(A) For the purposes of this subsection, compliance date means the date by which a source must comply with new or modified sections of this subchapter.

(B) Unless revised to reflect new regulatory requirements, an AMOC plan becomes void on the compliance date specified for a new or modified section of this subchapter affecting a source subject to an AMOC plan.

(C) The holder of an AMOC plan shall comply with the requirements of this subchapter if the AMOC plan becomes void.

(D) Upon final approval of an AMOC plan, the owner or operator of the sources affected by the plan shall keep a copy of the plan on the site affected by the plan and shall make the plan available upon request to representatives of the executive director, the EPA, or any local air pollution control agency having jurisdiction in the area.

(E) Upon request, each holder of an AMOC plan shall submit to the executive director a demonstration that the plan continues to meet all applicable criteria of this subsection.

(F) An AMOC holder is responsible for obtaining a new AMOC plan prior to the compliance date of any new or modified regulation of this subchapter that affects a source subject to an AMOC plan.

(8) Inclusion of Contiguous Properties. Notwithstanding paragraph (3)(A) of this subsection, an AMOC plan may cover multiple sources operated on contiguous properties, provided that separate requests for plan approval are submitted by each owner or operator subject to a control requirement under this subchapter.

§112.233. Monitoring Requirements.

(a) Separately for 29 FCCU Stack (EPN 29P1) and 40 FCCU Stack (EPN 40P1), the owner or operator shall install ~~Install~~, operate, calibrate, and maintain a continuous emissions monitoring system (CEMS) as specified in 40 Code of Federal Regulations (CFR) §60.105a(g)(1), (2) and (5) regardless of whether these provisions otherwise apply or provide exemptions for certain activities; use an analyzer with a minimum analyzer accuracy of plus or minus (±) 2.5%, a dedicated totalizing gas flow measurement system with a minimum measurement accuracy of ±5%, and temperature monitor with a minimum accuracy of ±1%; convert data from all monitoring devices to a common concentration, flow, pressure, and temperature measurement basis and calculate and record 15-minute and subsequent block one-hour average ~~to measure and record the~~ sulfur dioxide (SO_2) emissions. ~~and the exhaust gas flow rates; from EPN 29P1 and EPN 40P1 in accordance with the 40 Code of Federal Regulations (CFR) §60.105a(g).~~

(b) Separately for SRU Incinerator (EPN 34I1) and SCOT Unit Incinerator (EPN 43I1), the owner or operator shall install ~~Install~~, operate, calibrate, and maintain a CEMS as specified in 40 Code of Federal Regulations (CFR) §60.106a(a), regardless of whether these provisions otherwise apply; use an analyzer with an accuracy of plus or minus (±) 2.5%, a dedicated totalizing gas flow measurement system with an accuracy of ±5%, and temperature monitor with an accuracy of ±1%; convert data from all monitoring devices to a common concentration, flow, pressure, and temperature measurement basis to calculate and record 15-minute and subsequent block one-hour average ~~hourly~~ SO_2 emissions~~from EPN 34I1 and EPN 43I1 in accordance with 40 CFR §60.106a(a)~~.

(c) The owner or operator shall install, operate, calibrate, and maintain dedicated instrumentation according to the manufacturers' specifications to continuously and separately ~~Continuously~~ monitor the flow rate and the total sulfur concentration of the inlet gas streams of EPN 66FL1, EPN 66FL2, EPN 66FL3, and EPN 66FL12, ~~and EPN 66FL13 inlet gas stream~~ in accordance with the 40 CFR §60.107a(e) and (f)(1), regardless of whether these provisions otherwise apply or provide an exemption for any flare activities, as follows: ~~.~~

(1) monitor the total volumetric flow rate of gases routed to each flare using a separate dedicated totalizing gas flow meter with an accuracy of ±5%;

(2) monitor the temperature of gases routed to each flare using a separate temperature measurement device with an accuracy of ±1%; and

(3) monitor the sulfur content of the combined inlet flare gas stream as follows:

(A) using a separate dedicated analyzer capable of accurately measuring and recording total sulfur (including SO_2, hydrogen sulfide (H_2S), and organic sulfur compounds levels) with an accuracy of ±5% on a continuous basis, the sulfur concentration must be determined in accordance 40 CFR §60.107a(e)(1) regardless of applicability or exemptions, and determine hourly SO_2 emissions using the following equation; or

Figure: 30 TAC §112.233(c)(3)(A)

$$SO_2 = Scc \times FFa \times \frac{Tsc}{Ta} \times \frac{Pa}{Psc} \times \frac{lb\ mole}{385.27\ scf} \times \frac{64.06\ lb\ SO_2}{lb\ mole}$$

Where:

SO_2 = flare sulfur dioxide emissions in pounds per hour;

Scc = combined inlet flare stream total sulfur compound concentration in units of cubic feet of total inlet stream sulfur compounds per 1,000,000 cubic feet of total inlet stream flow;

FFa = combined inlet flare gas stream flow in actual cubic feet per hour;

Psc = regulatory standard condition pressure of 14.7 pounds per square inch (psia);

Pa = FFa measurement pressure in units of psia;

Tsc = regulatory standard condition temperature of 528 degrees Rankin; and

Ta = FFa measurement temperature in degrees Rankin.

(B) using a separate dedicated analyzer capable of accurately measuring and recording H_2S to an accuracy of ±5% on a continuous basis, determine the H_2S concentration in the flared gas stream, derive an inlet flare gas total sulfur concentration for each monitored hourly H_2S concentration in accordance 40 CFR §60.107a(e)(2) methodology regardless of applicability or exemptions, and calculate the SO_2 emissions from each flare for each operating hour using the following equation:

Figure: 30 TAC §112.233(c)(3)(B)

$$SO_2 = H_2Smc \times \frac{Scc}{H_2Ssc} \times FFa \times \frac{Tsc}{Ta} \times \frac{Pa}{Psc} \times \frac{lb\ mole}{385.27\ scf} \times \frac{64.06\ lb\ SO_2}{lb\ mole}$$

Where:

SO_2 = flare sulfur dioxide emissions in pounds per hour;

H_2Smc = monitored combined inlet flare stream hydrogen sulfide (H_2S) concentration in units of H_2S per 1,000,000 cubic feet of flow;

Scc = sampled composite inlet flare stream total sulfur compound concentration in units of cubic feet of total sulfur compounds per 1,000,000 cubic feet of flare gas;

H_2Ssc = sampled composite H_2S concentration in units of cubic feet of H_2S per 1,000,000 cubic feet of sample;

FFa = inlet gas stream flare flow in units of actual cubic feet per hour;

Psc = regulatory standard condition pressure of 14.7 pounds per square inch (psia);

Pa = FFa measurement pressure in units of psia;

Tsc = regulatory standard condition temperature of 528 degrees Rankin; and

Ta = FFa measurement temperature in degrees Rankin.

(d) The owner or operator shall continuously ~~Continuously~~ monitor the flow rate, temperature, and ~~the~~ total sulfur or H_2S concentration in the gases combusted by ~~for~~ each affected EPN listed in §112.230(b)(6) and (7) of this title (relating to Applicability), in accordance with 40 CFR §60.107a(a), (e) and (f)(1), except for the SRU Incinerator (EPN 34I1) and SCOT SRU Incinerator (EPN 43I1) that must be monitored under §112.233(b), as follows:~~.~~

(1) monitor the total volumetric fuel flow to each combustion device using a separate dedicated totalizing gas flow meter with an accuracy of ±5%; each fuel flow meter must be installed, calibrated, maintained, and operated per the manufacturer's recommendations and specifications;

(2) monitor the fuel temperature using a separate dedicated temperature monitor-with an accuracy of ±1%; that is installed, calibrated, maintained, and operated according to the manufacturer's recommendations and specifications; if the fuel temperature does not vary by more than ±1 throughout a common fuel supply system, the fuel temperature for each affected source supplied by the fuel supply system may be monitored at a single location; and

(3) monitor the fuel sulfur content either directly with a total sulfur analyzer or by monitoring the surrogate H_2S concentration as follows:

(A) if a total sulfur analyzer is used, calculate the emissions using the following equation; or

Figure: 30 TAC §112.233(d)(3)(A)

$$SO_2 = Fsc \times FFa \times \frac{Tsc}{Ta} \times \frac{Pa}{Psc} \times \frac{lb\ mole}{385.27\ scf} \times \frac{64.06\ lb\ SO_2}{lb\ mole}$$

Where:

SO_2 = affected combustion equipment sulfur dioxide emissions in pounds per hour;

Fsc = fuel total sulfur concentration in cubic feet per 1,000,000 cubic feet of flared gas;

FFa = fuel flow in actual cubic feet per hour;

Psc = regulatory standard condition pressure of 14.7 pounds per square inch (psia);

Pa = FFa measurement pressure in units of psia;

Tsc = regulatory standard condition temperature of 528 degrees Rankin; and

Ta = fuel temperature in degrees Rankin.

(B) if the H_2S concentration is monitored as a surrogate for the total sulfur content, calculate the SO_2 emissions as follows:

(i) collect at least one sample each month; the frequency of sampling may be reduced to no less than one time per calendar quarter if three consecutive monthly samples indicate that H_2S makes up 90.0 mole % or more of the total sulfur compounds in the fuel gas sample, and shall revert from quarterly to monthly when quarterly sample sulfur compounds consist of less than 90.0 mole % H_2S;

(ii) have the samples analyzed for total sulfur and H_2S concentrations;

(iii) use the following equation to calculate total SO_2 emission;

Figure: 30 TAC §112.233(d)(3)(B)(iii)

$$SO_2 = H_2Sfc \times \frac{Fsc}{H_2Ssc} \times FFa \times \frac{Tsc}{Ta} \times \frac{Pa}{Psc} \times \frac{lb\ mole}{385.27\ scf} \times \frac{64.06\ lb\ SO_2}{lb\ mole}$$

Where:

SO_2 = affected combustion equipment SO_2 emissions in lb/hr;

H_2Sfc = fuel hydrogen sulfide (H_2S) concentration in units of actual cubic feet of H_2S per 1,000,000 actual cubic feet of fuel from the analysis in 112.233(d)(3)(B)(ii);

Fsc = total fuel sulfur compounds concentration in cubic feet per 1,000,000 cubic feet fuel gas from the analysis in 112.233(d)(3)(B)(ii) of this section;

H_2Ssc = sampled H_2S concentration in cubic feet per 1,000,000 cubic feet fuel gas;

FFa = fuel flow in actual cubic feet per hour;

Psc = regulatory standard condition pressure of 14.7 pounds per square inch (psia);

Pa = FFa measurement pressure in units of psia;

Tsc = regulatory standard condition temperature of 528 degrees Rankin; and

Ta = fuel temperature in degrees Rankin.

(iv) sum the emissions for each affected source in §112.230(b)(6) of this title as calculated in §112.233(b) and (d) of this section to determine compliance with the total EPN FLEX_R_CAP SO_2 hourly emission limit; and

(v) sum the emissions for each affected source in §112.230(b)(7) of this title as calculated in §112.233(d) of this title to determine compliance with the total EPN FLEX_MS_CAP SO_2 hourly emissions limit.

(e) Continuous monitoring data collected in accordance with requirements in this section must undergo an appropriate quality assurance and quality control process and be validated for at least 95% of the time that the monitored emission point has emissions; an owner or operator must utilize an appropriate data substitution process based on the most accurate methodology available, which is at least equivalent to engineering judgement, to obtain all missing or invalidated monitoring data for the remaining period the monitored emission point has emissions.

(f) Minor modifications to monitoring methods may be approved by the executive director. Monitoring methods other than those specified in this section may be used if approved by the executive director and validated by 40 CFR Part 63, Appendix A, Test Method 301. For the purposes of this subsection, substitute "executive director" in each place that Test Method 301 references "administrator." These validation procedures may be waived by the executive director or a different protocol may be granted for site-specific applications. Minor modifications that may be approved under this subsection include increases in the frequency of monitoring and the replacement of parametric monitoring with direct emissions monitoring with a CEMS provided appropriate quality assurance control, accuracy specifications, and data validation requirements are specified and no less stringent than monitoring requirements for a comparable EPN in this division.

§112.234. Testing Requirements.

(a) Perform continuous emissions monitoring system (CEMS) relative accuracy tests in accordance with 40 Code of Federal Regulations (CFR) §60.105a(g)(2) for the Unit 29 FCCU Stack (EPN 29P1) and the Unit 40 FCCU Stack (EPN 40P1) and 40 CFR §60.106a(1)(iii) for the SRU Incinerator (EPN 34I1) and the SCOT SRU Incinerator (EPN 43I1).

(b) Perform initial and subsequent testing of ~~for~~ monitoring devices required by §112.233 of this title (relating to Monitoring Requirements) in accordance with the manufacturer's specifications to ensure that the required monitoring instrumentation is ~~monitors are~~ calibrated and functional. Initial testing must be completed ~~function properly~~ by the compliance date in §112.238 of this title (relating to Compliance Schedules). If a monitoring device has been previously tested in accordance with the manufacturer's specifications and a record is available to document proper procedures were followed, then an owner or operator is not required to repeat the initial testing again under §112.234(b) provisions.

(c) Conduct additional performance testing, if requested by the executive director, in compliance with 40 CFR §60.104a to demonstrate compliance with applicable emission limits or standards. The notification requirements of 40 CFR §60.8(d) apply to each initial performance test and to each subsequent performance test required by the executive director, except for performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments. All performance tests must be conducted using test methods allowed in §112.235 of this title (relating to Approved Test Methods).

(d) When analysis of fuels, including but not limited to refinery gas, is required under §112.233 of this title, the owner or operator shall use a test method in §112.235 of this title for the analysis.

§112.235. Approved Test Methods.

(a) Tests required under §112.234 of this title (related to Testing Requirements) must be conducted using the test methods in 40 Code of Federal Regulations (CFR) Part 60, Appendices A-1 through A-8 and Appendix B or other methods as specified in this section, except as provided in 40 CFR §60.8(b) ~~(*36 Federal Register* (FR) 24877, published Dec. 23, 1971, as amended through 81 FR 59809, published Aug. 30, 2016)~~.

(b) Sulfur dioxide ~~(SO_2)~~ in exhaust gases must be determined using United States Environmental Protection Agency (EPA) Test Method 6 or 6C (40 CFR, Part 60, Appendix A).

(c) For flares subject to emissions limitations or standards in §112.232 of this title (relating to Control Requirements), the owner or operator shall use flare test methods and procedures in 40 CFR §60.104a ~~(73 FR 35867, published June 24, 2008 as amended 77 FR 56470, published September 12, 2012 and 80 FR 75231, published December 1, 2015)~~.

(d) Fuel and waste gas sulfur ~~Sulfur~~ content ~~of fuels~~ must be determined using American Society for Testing and Materials (ASTM) Method D6667 (Determination of Total Volatile Sulfur in Gaseous Hydrocarbons), ASTM Method D1945 (Standard Test Method for Analysis of Natural Gas by Gas Chromatography), EPA Method 15A or 16A of Appendix A to 40 CFR Part 60, ASTM Method D4468, or ASTM Method D5504 if it is conducted in a manner that analyzes all sulfur-containing compounds present. ~~D1945-~~

~~91 or ASTM Method D3588-93 for fuel composition.~~

(e) Alternate test methods as approved by the executive director and the EPA may be used.

§112.236. Recordkeeping Requirements.

The owner or operator shall maintain records in written or electronic format sufficient to demonstrate compliance with each applicable requirement for a minimum of five years, including but not limited to:

(1) all monitoring data and sampling analyses, including but not limited to continuous emissions monitoring system flow rate and sulfur composition data, used to quantify emissions~~, and for EPN 29P1 and EPN 40P1, authorized MSS activities records including one-hour average exhaust flow rates in am³/hr and emission rates;~~

(2) the methodology and any associated calculations employed to determine compliance;

(3) documentation of any period that emission limits or standards were exceeded, and exceedance reports submitted to the appropriate Texas Commission on Environmental Quality regional office; and

(4) copies of test reports for tests conducted in accordance with §112.225 and associated records ~~copies of emission test data and records~~.

§112.237. Reporting Requirements.

(a) For a source that is subject to an emissions limit in §112.232 of this title (relating to Control Requirements) and that exceeds an applicable emission limit or fails to meet a required stack parameter, the owner or operator shall submit to the Texas Commission on Environmental Quality (TCEQ) Regional Office for the area where the plant is located a report by March 31 of the year after an exceedance occurs documenting the excess emissions during the preceding calendar year, including at least the following:

(1) the date that each exceedance or failure to meet a required stack parameter occurred;

(2) an explanation of the exceedance or failure to meet a required stack parameter;

(3) a statement of whether the exceedance or failure to meet a required stack parameter was concurrent with a maintenance, startup, or ~~and~~ shutdown period for, or malfunction of, an affected source ~~facility~~ or control system;

(4) a description of the action taken, if any; and

(5) a written statement, signed by the owner or operator, certifying the accuracy and completeness of the information contained in the report.

(b) The owner or operator shall submit a copy of each performance ~~stack~~ test report to the TCEQ Regional Office and any local air pollution control agency having jurisdiction for the area where the plant is located within 60 days after completion of the test.

(c) After the effective date of a determination by the Environmental Protection Agency (EPA) that the Hutchinson County sulfur dioxide (SO_2) nonattainment area has failed to attain the 2010 one-hour SO_2 National Ambient Air Quality Standard or failed to meet reasonable further progress (RFP) pursuant to Federal Clean Air Act §179(c), 42 United States Code §7509(c), the TCEQ will notify the owner or operator of the failure to attain and that the contingency measures in this subsection are triggered. Once notification is received from the TCEQ, the owner or operator shall perform a full system audit (FSA) of all SO_2 sources subject to §112.230 of this title (relating to Applicability).

(1) Within 90 calendar days after the date of the notification, the owner or operator shall submit the FSA, including recommended provisional SO_2 emission control strategies as necessary, to the executive director of the TCEQ.

(2) As part of the FSA, the owner or operator shall conduct a root cause analysis of the circumstances surrounding the cause of the determination of failure to attain or failure to meet RFP, including a review and consideration of the following:

(A) for all causes of the determination of failure to attain or failure to meet RFP, at a minimum, hourly mass emissions of SO_2 from each SO_2 source subject to this division; and

(B) for a determination of failure to attain based on ambient air monitor data or modeling data, at a minimum, the meteorological conditions recorded at the monitor or other relevant meteorological data, including the frequency distribution of wind direction temporally correlated with SO_2 readings greater than 75 parts per billion at the monitor for which the EPA's determination of failure to attain was made; and any emissions ~~exceptional~~ event that may have occurred. The root cause analysis and associated records used to conduct the audit must consider information on the days that monitored exceedances occurred during the time period that the EPA evaluated in making the failure to attain determination.

§112.238. Compliance Schedules.

The owner or operator of a source subject to §112.230 of this title (relating to Applicability) shall comply with the requirements of this division ~~as soon as~~

~~practicable, but~~ no later than January 1, 2025.

SUBCHAPTER F – REQUIREMENTS IN THE HUTCHINSON COUNTY NONATTAINMENT AREA

DIVISION 5 – REQUIREMENTS FOR THE TOKAI BORGER CARBON BLACK PLANT

§§112.240 - 112.248

Statutory Authority

The new sections are adopted under Texas Water Code (TWC), §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new sections are also adopted under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.014, concerning Emission Inventory, which authorizes the commission to require companies whose activities cause emissions of air contaminants to submit information to enable the commission to develop an inventory of emissions; THSC, §382.015, concerning Power to Enter Property, which authorizes a member, employee, or agent of

the commission to enter public or private property to inspect and investigate conditions relating to emissions of air contaminants; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants, as well as require recordkeeping; and THSC, §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe sampling methods and procedures to be used in determining violations of and procedures to be used in determining compliance.

The adopted new sections implement TWC, §5.103 and §5.105 and THSC, §§382.002, 382.011, 382.012, 382.015, 382.016, 382.017 and 382.021.

§112.240. Applicability.

(a) The requirements in this division apply to affected sources at the Tokai Borger Carbon Black Plant site, which is located at 9455 FM 1559 in Borger, Texas ~~(Regulated Entity Number (RN) 100222413)~~ in the Hutchinson County sulfur dioxide ~~(SO_2)~~ nonattainment area. Affected sources will remain subject to this division regardless of ownership, operational control, or other documentation changes. ~~Once approved by the United States Environmental Protection Agency (EPA), the requirements in this division continue to apply until the EPA approves their removal.~~

(b) Affected existing sources are designated by the source name and emission point number (EPN) ~~and source name~~ used in the site's New Source Review (NSR) permit as issued on the specified date. Applicable control devices to be authorized and constructed are similarly designated by the EPN that the company used to designate the future unit in the attainment demonstration modeling, with an appropriate name also used in the rules. The specific affected sources are as follows:

(1) ~~EPN 119,~~ Boiler Stacks, Boiler 1 and 2 Common Stack (EPN 119)~~,~~ in NSR Permit 1867A dated July 21, 2020;

(2) ~~EPN 121,~~ Plant 1 Dryer Stack (EPN 121)~~,~~ designated in NSR Permit 1867A dated July 21, 2020;

(3) ~~EPN 122,~~ Plant 2 Dryer Stack (EPN 122)~~,~~ in NSR Permit 1867A dated July 21, 2020;

(4) ~~EPN 1,~~ Plant 1 Number 1 and Number 2 Dryer Purge Stack (EPN 1)~~,~~ in NSR Permit 1867A dated July 21, 2020;

(5) ~~EPN 3,~~ Plant 1 Number 3 and Number 4 Dryer Purge Stack (EPN 3)~~,~~ in NSR Permit 1867A dated July 21, 2020;

(6) EPN Flare-1, EPN Flare-2, EPN Flare-3 and EPN Flare-4, which are the four flares for the carbon black reactors, designated in NSR Permit 1867A dated July

21, 2020; and

(7) New Flare (EPN New Flare)~~, New Flare,~~ if authorized and constructed to replace all existing flares (EPN Flare-1, EPN Flare-2, EPN Flare-3, and EPN Flare-4) for the carbon black reactors.

§112.241. Definitions.

Unless specifically defined in the Texas Clean Air Act (Texas Health and Safety Code, Chapter 382), or in §101.1 or §112.1 of this title (relating to Definitions, respectively), the terms in this division have the meanings commonly used in the field of air pollution control. The following meanings apply in this division unless the context clearly indicates otherwise.

(1) Block one-hour average--An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the next clock hour (e.g., from 12:00:00 to 12:59:59).

(2) Continuous Monitoring--Monitoring for which readings are recorded at least once every 15 minutes.

(3) ~~(2)~~ Hutchinson County sulfur dioxide (SO_2) nonattainment area--The portion of Hutchinson County designated by the United States Environmental

Protection Agency (EPA) as nonattainment for the 2010 SO_2 National Ambient Air Quality Standard, 40 Code of Federal Regulations §81.344, as published on March 26, 2021 ~~(86 *Federal Register* 16055), effective April 30, 2021~~.

~~(3) Pipeline quality natural gas--Natural gas containing no more than 0.25 grain of hydrogen sulfide and 5 grains of total sulfur per 100 dry standard cubic feet.~~

(4) Production unit--The carbon black oil furnace or group of carbon black oil furnaces, dryers or groups of dryers, and any ancillary units used in the manufacture of carbon black and producing tail gas.

(5) Tail gas--The exit gaseous stream of a carbon black oil furnace consisting of water vapor, carbon monoxide, hydrogen, pyrolysis by-products, and reduced and organic sulfur compounds as a result of the manufacture of carbon black.

§112.242. Control Requirements.

~~(a) An owner or operator may not change the Regulated Entity Number (RN) or emission point number (EPN) designation of any source subject to §112.240 of this title (relating to Applicability) or otherwise contravene any of the control requirements in this section without the prior approval of the executive director and the United States Environmental Protection Agency (EPA).~~

(a) ~~(b)~~ Hourly mass emissions of sulfur dioxide (SO_2), on a block one-hour average, may not exceed the following when Boilers 1 or 2, singly or together, are operating:

(1) 109.10 lb/hr SO_2 for ~~EPN 119 (~~Boiler Stacks, Boiler 1 and 2 Common Stack (EPN 119);

(2) 441.40 lb/hr SO_2 for ~~EPN 121 (~~Plant 1 Dryer Stack (EPN 121); and

(3) 595.60 lb/hr SO_2 for ~~EPN 122~~ Plant 2 ~~(~~Dryer Stack (EPN 122).

(b) ~~(c)~~ If the new flare (EPN New Flare) is not authorized, constructed, and operated, hourly mass emissions of SO_2, on a block one-hour average, may not exceed the following when neither Boiler ~~both Boilers~~ 1 nor ~~and~~ 2 is ~~are not~~ operating:

(1) 420.00 lb/hr SO_2 for ~~EPN Flare-1 (~~Plant 1, Unit 1 Primary Bag Filter Flare (EPN Flare-1);

(2) 0.00 lb/hr SO_2 for ~~EPN 119 (~~Boiler Stacks, Boiler 1 and 2 Common Stack (EPN 119);

(3) 250.00 lb/hr SO_2 for ~~EPN 121 (~~Plant 1 Dryer Stack (EPN 121); and

(4) 400.00 lb/hr SO_2 for ~~EPN 122 (~~Plant 2 Dryer Stack (EPN 122).

(c) ~~(d)~~ If New Flare (EPN New Flare) ~~(New-Flare)~~ is authorized, constructed, and operated, hourly mass emissions of SO_2, on a block one-hour average, may not exceed the following when neither Boiler ~~both Boilers~~ 1 nor ~~and~~ 2 is ~~are not~~ operating:

(1) 806.60 lb/hr SO_2 for New Flare (EPN New Flare) ~~(New-Flare)~~;

(2) 0.00 lb/hr SO_2 for the ~~EPN 119 (~~Boiler Stacks, Boiler 1 and 2 Common Stack (EPN 119);

(3) 272.50 lb/hr SO_2 for ~~EPN 121 (~~Plant 1 Dryer Stack (EPN 121); and

(4) 436.00 lb/hr SO_2 for ~~EPN 122 (~~Plant 2 Dryer Stack (EPN 122).

(d) ~~(e)~~ Tail gas may only be combusted in a source ~~facility~~ whose emissions are routed to the ~~EPN 119 (~~Boiler 1 and 2 Common Stack (EPN 119), ~~EPN 121 (~~Plant 1 Dryer Stack (EPN 121), ~~EPN 122 (~~Plant 2 Dryer Stack (EPN 122), ~~EPN Flare-1 (~~Plant 1, Unit 1 Primary Bag Filter Flare (EPN Flare-1), or New Flare (EPN New Flare) ~~(New-Flare)~~.

(e) ~~(f)~~ Sulfur or sulfur containing compounds may not be routed to ~~If EPN New Flare (New-Flare) is not authorized, constructed, and operated,~~ EPN Flare-2, EPN Flare-3, and EPN Flare-4 ~~may not operate~~ on or after the compliance date in §112.248 of this title (relating to Compliance Schedules).

(f) ~~(g)~~ If New Flare (EPN New Flare) ~~(New-Flare)~~ is authorized, constructed, and operated, sulfur or sulfur containing compounds may not be routed to the Plant 1, Unit 1 Primary Bag Filter Flare (EPN Flare-1)~~, EPN Flare-2, EPN Flare-3, and EPN Flare-4 may not operate~~ on or after the compliance date in §112.248 of this title.

(g) ~~(h)~~ Sulfur or sulfur containing compounds may not be routed to the ~~EPN 1 (~~Plant 1 Number 1 and Number 2 Dryer Purge Stack (EPN 1) and ~~EPN 3 (~~Plant 1 Number 3 and Number 4 Dryer Purge Stack (EPN 3) ~~may not operate~~ on or after the compliance date in §112.248 of this title.

(h) ~~(i)~~ If the New Flare (EPN New Flare) ~~(New-Flare)~~ is authorized, constructed, and operated, it must meet the following parameters:

~~(1) EPN New Flare (New-Flare) must receive all waste gases instead of EPN Flare-1, EPN Flare-2, EPN Flare-3, and EPN Flare-4;~~

(1) ~~(2)~~ tail gas may be routed to the New Flare (EPN New Flare) ~~(New-Flare)~~ only when neither Boiler ~~Boilers~~ 1 nor ~~and~~ 2 is ~~are not~~ operating; and

(2) ~~(3)~~ The New Flare (EPN New Flare) ~~(New-Flare)~~ must be constructed with a stack height of ~~no less than~~ 60.35 meters and must be located at Universal

Transverse Mercator (UTM) coordinates UTM East Meters 279488 and UTM North Meters 3949627 in UTM Zone 14.

(i) ~~(j)~~ If the New Flare (EPN New Flare) ~~(New-Flare)~~ is not authorized, constructed, and operated, tail gas may be routed to the ~~EPN Flare-1 (~~Plant 1, Unit 1 Primary Bag Filter Flare (EPN Flare-1) only when neither Boiler ~~Boilers~~ 1 nor ~~and~~ 2 is ~~are not~~ operating.

(j) ~~(k)~~ The owner or operator may request an alternate means of control under the provisions of §112.232(k) of this title (relating to Control Requirements). ~~alternative SO_2 emission limit if dispersion modeling and analysis consistent with the most recent attainment demonstration confirms the alternative limit will not increase the modeled regulatory design value in the nonattainment area. The alternative limit and any deviations from the modeling methodology from the most recent attainment demonstration must be approved by the executive director and the EPA.~~

§112.243. Monitoring Requirements.

(a) The owner or operator shall install ~~Install~~, calibrate, and maintain a ~~CEMS~~ continuous emissions monitoring system (CEMS) to monitor exhaust sulfur dioxide (SO_2) ~~SO_2~~ from the ~~EPN 119 (~~Boiler Stacks, Boiler 1 and 2 Common Stack (EPN 119) in accordance with the requirements of 40 Code of Federal Regulations (CFR) §60.13, 40 CFR Part 60, Appendix B, Performance Specification 2 and 6, for SO_2, and 40 CFR Part

60, Appendix F, quality assurance procedures.~~40 CFR~~ ~~Part 60 as follows~~

~~(1) §60.13;~~

~~(2) Appendix B, Performance Specification 2, for SO_2; and~~

~~(3) Appendix F, quality assurance procedures.~~

(b) The owner or operator shall monitor ~~Monitor~~ the sulfur content of the carbon black oil feedstock and produced carbon black, as well as the production rate of the carbon black, as follows:

(1) measure twice daily at least four hours apart the sulfur content by weight of the carbon black oil in the feed to each production unit according to the requirements of §112.245 of this title (relating to Approved Test Methods);

(2) for each grade of carbon black produced, measure daily the sulfur content by weight of the carbon black produced by each carbon black production unit according to the requirements of §112.245 of this title; and

(3) determine hourly the amount of each grade of carbon black produced by each carbon black production unit.

(c) The owner or operator shall install ~~Install~~, calibrate, maintain, and operate one or more totalizing fuel flow meters, with an accuracy of ± 5%, to continuously measure the feed rate of carbon black oil feedstock supplied to each carbon black production unit.

(d) The owner or operator shall install ~~Install~~, calibrate, maintain, and operate totalizing tail gas flow meters, with an accuracy of ± 5%, to continuously measure the volumetric flow rate of tail gas to each tail gas combustion device covered under §112.242 of this title (relating to Control Requirements).

(e) Continuous monitoring data collected in accordance with requirements in this subsection must undergo an appropriate quality assurance and quality control process and be validated for at least 95% of the time that the monitored emission point has emissions; an owner or operator must utilize an appropriate data substitution process based on the most accurate methodology available, which is at least equivalent to engineering judgment, to obtain all missing or invalidated monitoring data for the remaining period the monitored emission point has emissions.

(f) The owner or operator shall calculate hourly ~~Calculate total~~ SO_2 emissions from the Plant 1 Dryer Stack (EPN 121) using the following equation. ~~each carbon black production unit using the equation in subsection (j) of this section which assumes that all the sulfur in the carbon black oil feedstock, which is not accounted for by sulfur in the carbon black product, is converted to~~ ~~SO_2.~~

Figure: 30 TAC §112.243(f)

$$SO_{2,121} = \sum_{i=1}^{\tau}(\pi_{121} \times \sigma_i)$$ ■

Where:

$SO_{2,121}$ = Emissions of SO_2 expressed in units of pounds per hour from EPN 121;

i = the carbon black production units;

τ = the number of carbon black production units contributing carbon black oil furnace tail gas to EPN 121;

σ_i = emissions of SO_2 expressed in units of pounds per hour calculated by §112.243(j) of this title for each production unit contributing carbon black oil furnace tail gas to EPN 121; and

π_{121} = the split coefficient determined by dividing the volumetric flow of tail gas to EPN 121 divided by the total volumetric flow of tail gas generated by each carbon black production unit contributing carbon black oil furnace tail gas to EPN 121.

(g) The owner or operator shall calculate hourly SO_2 emissions from the Plant 2 Dryer Stack (EPN 122) using the following equation. ~~If EPN New Flare (New-Flare) is not authorized, constructed, and operated, demonstrate compliance with the allowable emission requirements of §112.242 of this title for EPN 121 (Plant 1 Dryer Stack), EPN 122 (Plant 2 Dryer Stack), and EPN Flare-1 (Plant 1, Unit 1 Primary Bag Filter Flare) by calculating the actual hourly emissions of SO_2 by using the mass balance approach in subsection (j) of this section as well as the ratio of the total volumetric flow of tail gas to the boilers or flare versus the total volumetric flow of tail gas and the ratio of the total volumetric flow of tail gas to the dryers versus the total volumetric flow of tail gas.~~

Figure: 30 TAC §112.243(g)

$$SO_{2,122} = \sum_{i=1}^{\tau} (\pi_{122} \times \sigma_i)$$

Where:

$SO_{2,122}$ = Emissions of SO_2 expressed in units of lb/hr from the Plant 2 Dryer Stack (EPN 122);

i = the carbon black production units;

τ = the number of carbon black production units contributing carbon black oil furnace tail gas to the Plant 2 Dryer Stack (EPN 122);

σ_i = emissions of SO_2 expressed in units of pounds per hour calculated by §112.243(j) of this section for each production unit contributing carbon black oil furnace tail gas to the Plant 2 Dryer Stack (EPN 122); and

π_{121} = the split coefficient determined by dividing the volumetric flow of tail gas to the Plant 2 Dryer Stack (EPN 122); divided by the total volumetric flow of tail gas generated by each carbon black production unit contributing carbon black oil furnace tail gas to the Plant 2 Dryer Stack (EPN 122).

(h) The owner or operator shall calculate hourly SO_2 emissions from the New Flare (EPN New Flare) or Plant 1, Unit 1 Primary Bag Filter Flare (EPN Flare-1), as applicable using the following equation. ~~If EPN New Flare (New-Flare) is authorized, constructed, and operated, demonstrate compliance with the applicable emission requirements of §112.242 of this title for EPN 121 (Plant 1 Dryer Stack), EPN 122 (Plant 2 Dryer Stack), and EPN New Flare (New Flare) by calculating the actual hourly emissions of SO_2 by using the mass balance approach in subsection (j) of this section as well as the ratio of the volumetric flow of tail gas to the boilers or flare versus the~~

~~total volumetric flow of tail gas and the ratio of the total volumetric flow of tail gas to the dryers versus the total volumetric flow of tail gas.~~

Figure: 30 TAC §112.243(h)

$$SO_{2,Flare} = \sum_{i=1}^{\tau} (\pi_{Flare} \times \sigma_i)$$ ■

Where:

$SO_{2,Flare}$ = Emissions of SO_2 expressed in units of pounds per hour from the Plant 1, Unit 1 Primary Bag Filter Flare (EPN Flare 1) or New Flare (EPN New Flare) as applicable;

i= the carbon black production units;

τ = the number of carbon black production units contributing carbon black oil furnace tail gas to the flare;

σ_i = emissions of SO_2 expressed in units of pounds per hour calculated by 30 TAC §112.243(j) for each production unit contributing carbon black oil furnace tail gas to the flare; and

π_{Flare} = the split coefficient determined by dividing the volumetric flow of tail gas to the flare divided by the total volumetric flow of tail gas generated by each carbon black production unit contributing carbon black oil furnace tail gas to the flare.

(i) Emissions ~~Actual emissions~~ of SO_2 from each EPN specified under §112.242 of this title ~~for each operational scenario occurring~~ during any block one-hour period must be determined on a block one-hour average.

(j) The owner or operator shall calculate ~~Calculate~~ total SO_2 emissions generated by ~~from~~ each production unit using the following equation.

Figure: 30 TAC §112.243(j)

$$\sigma_i = [(S_{oil} \times D_{oil} \times F_{oil}) - (S_p \times P_p)] \times 2$$

Where:

σ_i = emissions of SO_2 generated by each production unit in units of pounds per hour;

i = the carbon black production unit;

S_{oil} = weight of sulfur in carbon black oil in units of pounds of sulfur per pound of carbon black oil;

D_{oil} = density of carbon black oil in pounds per gallon determined at a temperature consistent with the carbon black oil feed;

F_{oil} = feed rate of oil to carbon black production unit in gallons per hour;

S_p= sulfur content of carbon black product as determined in units of pound of sulfur per pound of product;

P_p = production rate of carbon black product in units of pounds per hour; and

2 = the molecular weight ratio of SO_2 to sulfur.

$$\cancel{SO_2 = (SI - SRB) \times 2}$$

~~Where:~~

~~SO_2 = mass emissions of SO_2, expressed in units of lb/hr;~~

~~SI = the sulfur input from the carbon black oil feedstock determined by sampling as required by §112.243(2)(A);~~

~~SRB = the sulfur retained in the produced carbon black determined by sampling as required by §112.243(b)(2) §112.243(2)(B);~~

~~2 = the molecular weight ratio of SO_2 to sulfur.~~

(k) In lieu of the monitoring requirements of §112.243(b) - (d) of this section and §112.243(f) - (j) of this section, the owner or operator may install, operate, calibrate, and maintain a continuous emissions monitoring system to monitor exhaust sulfur dioxide (SO_2) from Plant 1 Dryer Stack (EPN 121) or Plant 2 Dryer Stack (EPN 122) in accordance with the requirements of 40 Code of Federal Regulations (CFR) §60.13, 40 CFR Part 60, Appendix B, Performance Specification 2 and 6, for SO_2, and 40 CFR Part 60, Appendix F, quality assurance procedures. If a CEMS is not used to monitor the emissions from both EPNs, monitoring requirements in §112.243(b) - (d) of this section and §112.243(f) - (j) of this section continue to apply to EPNs without a CEMS.

(l) Minor modifications to monitoring methods may be approved by the executive director. Monitoring methods other than those specified in this section may be used if approved by the executive director and validated by 40 CFR Part 63, Appendix A, Test Method 301. For the purposes of this subsection, substitute "executive director" in each place that Test Method 301 references "administrator." These validation procedures may be waived by the executive director or a different protocol may be granted for site-specific applications. Minor modifications that may be approved under this subsection include increases in the frequency of monitoring provided appropriate quality assurance control, accuracy specifications, and data validation requirements are specified and no less stringent than monitoring requirements for a comparable EPN in this division.

§112.244. Testing Requirements.

(a) The owner or operator shall perform ~~Perform~~ an initial demonstration of compliance test on the emission points specified in §112.242(a) - (c) ~~§112.242(b) - (d)~~ of this title (relating to Control Requirements) for sulfur dioxide ~~(SO_2)~~, while the associated sources ~~facilities~~ are firing tail gas, except for flares, by the compliance date in §112.248 of this title (relating to Compliance Schedules).

(b) The owner or operator shall use ~~Use~~ the methods provided in §112.245 of this title (relating to Approved Test Methods) for the initial demonstration of compliance test required under subsection (a) of this section.

(c) During performance ~~stack~~ testing, the owner or operator shall operate the source ~~facility~~ at the maximum rated capacity, or as near thereto as practicable.

(d) The owner or operator shall conduct ~~Conduct~~ additional performance testing at least every five years and when requested by the executive director using test methods allowed in §112.245 of this title.

(e) When analysis of produced carbon black, carbon black oil, and fuels, including but not limited to tail gas, is required for monitoring under §112.243 of this title (relating to Monitoring Requirements), the owner or operator shall use a test method in §112.245 of this title for the analysis.

§112.245. Approved Test Methods.

(a) Tests required under §112.244 of this title (relating to Testing Requirements) must be conducted using the test methods in 40 Code of Federal Regulations (CFR) Part 60, Appendices A-1 through A-8 and Appendix B or other methods as specified in this section, except as provided in §60.8(b) ~~(*36 Federal Register* (FR) 24877, published Dec. 23, 1971, as amended through 81 FR 59809, published Aug. 30, 2016)~~.

(b) Sulfur dioxide ~~(SO_2)~~ in exhaust gases must be determined using United States Environmental Protection Agency (EPA) Test Method 6 or 6C (40 CFR, Part 60, Appendix A).

(c) For flares subject to emissions limitations or standards in §112.242 of this title (relating to Control Requirements), the owner or operator shall use flare test methods and procedures in 40 CFR §60.104a ~~(73 FR 35867, published June 24, 2008 as amended 77 FR 56470, published September 12, 2012 and 80 FR 75231, published December 1, 2015)~~ as if the federal rules apply to carbon black plants.

(d) Sulfur content of fuels and carbon black oil must be determined using American Society for Testing and Materials (ASTM) Method D4294 ~~D1945-91 or ASTM Method D3588-93~~ for fuel composition.

(e) Sulfur content of carbon black must be determined using ASTM Test Method D1619.

(f) Alternate test methods as approved by the executive director and the EPA may be used.

§112.246. Recordkeeping Requirements.

The owner or operator shall maintain records in written or electronic format sufficient to demonstrate compliance with each applicable requirement for a minimum of five years, including but not limited to:

(1) records in units of pounds per hour (lb/hr) of production of carbon black for each grade of carbon black from each carbon black production unit;

(2) twice daily records of sulfur content by weight of the carbon black oil feedstock;

(3) daily records of sulfur content by weight of the carbon black produced for each grade of carbon black produced by each carbon black production unit;

(4) records of continuous carbon black oil feedstock flow rates for each carbon black production unit;

(5) records of continuous tail gas volumetric flow rates to each tail gas combustion device from each production unit covered by §112.242 of this title (relating to Control Requirements);

(6) for each block one-hour period of operation of a carbon black production unit, the required mass balance calculations of emissions of sulfur dioxide (SO_2) ~~SO_2~~ from each EPN for those sources in operation without a continuous emissions monitoring system (CEMS) for SO_2 ~~and for control devices~~;

(7) the continuous emissions monitoring data of emissions of SO_2 for each EPN ~~for those sources~~ in operation with a CEMS for SO_2; ~~and~~

(8) documentation of any period that emission limits or standards were exceeded, and copies of exceedance reports submitted to the appropriate Texas Commission on Environmental Quality regional office; and ~~copies of required emission test data and records.~~

(9) copies of test reports for tests conducted in accordance with §112.244 of this title (relating to Testing Requirements) and associated records.

§112.247. Reporting Requirements.

(a) For a source that is subject to an emissions limit in §112.242 of this title (relating to Control Requirements) and that exceeds an applicable emission limit or fails to meet a required stack parameter, the owner or operator shall submit to the Texas Commission on Environmental Quality (TCEQ) Regional Office for the area where the plant is located a report by March 31 of the year after an exceedance occurs documenting the excess emissions during the preceding calendar year, including at least the following:

(1) the date that each exceedance or failure to meet a required stack parameter occurred;

(2) an explanation of the exceedance or failure to meet a required stack parameter;

(3) a statement of whether the exceedance or failure to meet a required stack parameter was concurrent with an authorized maintenance, startup, or ~~and~~ shutdown activity for, or malfunction of, an affected source ~~facility~~ or control system;

(4) a description of the action taken, if any; and

(5) a written statement, signed by the owner or operator, certifying the accuracy and completeness of the information contained in the report.

(b) The owner or operator shall submit a copy of each performance ~~stack~~ test report to the TCEQ Regional Office and any local air pollution control agency having jurisdiction for the area where the plant is located within 60 days after completion of the test.

(c) After the effective date of a determination by the Environmental Protection Agency (EPA) that the Hutchinson County sulfur dioxide (SO_2) nonattainment area has failed to attain the 2010 one-hour SO_2 National Ambient Air Quality Standard or failed to meet reasonable further progress (RFP) pursuant to federal ~~Federal~~ Clean Air Act §179(c), 42 United States Code §7509(c), the TCEQ will notify the owner or operator of the failure to attain and that the contingency measures in this subsection are triggered. Once notification is received from the TCEQ, the owner or operator shall perform a full system audit (FSA) of all SO_2 sources subject to §112.240 of this title (relating to Applicability).

(1) Within 90 calendar days after the date of the notification, the owner or operator shall submit the FSA, including recommended provisional SO_2 emission control strategies as necessary, to the executive director of the TCEQ.

(2) As part of the FSA, the owner or operator shall conduct a root cause analysis of the circumstances surrounding the cause of the determination of failure to attain or failure to meet RFP, including a review and consideration of the following:

(A) for all causes of the determination of failure to attain or failure to meet RFP, at a minimum, hourly mass emissions of SO_2 from each SO_2 source subject to this division; and

(B) for a determination of failure to attain based on ambient air monitor data or modeling data, at a minimum, the meteorological conditions recorded at the monitor or other relevant meteorological data, including the frequency distribution of wind direction temporally correlated with SO_2 readings greater than 75 parts per billion at the monitor for which the EPA's determination of failure to attain was made; and any emissions ~~exceptional~~ event that may have occurred. The root cause analysis and associated records used to conduct the audit must consider information on the days that monitored exceedances occurred during the time period that the EPA evaluated in making the failure to attain determination.

§112.248. Compliance Schedules.

The owner or operator of a source subject to §112.240 of this title (relating to Applicability) shall comply with the requirements of this division ~~as soon as practicable, but~~ no later than January 1, 2025.

SUBCHAPTER G: REQUIREMENTS IN THE NAVARRO COUNTY NONATTAINMENT AREA

§§112.300 - 112.308

Statutory Authority

The new sections are adopted under Texas Water Code (TWC), §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new sections are also adopted under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.014, concerning Emission Inventory, which authorizes the commission to require companies whose activities cause emissions of air contaminants to submit information to enable the commission to develop an inventory of emissions; THSC, §382.015, concerning Power to Enter Property, which authorizes a member, employee, or agent of

the commission to enter public or private property to inspect and investigate conditions relating to emissions of air contaminants; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants, as well as require recordkeeping; and THSC, §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe sampling methods and procedures to be used in determining violations of and procedures to be used in determining compliance.

The adopted new sections implement TWC, §5.103 and §5.105 and THSC, §§382.002, 382.011, 382.012, 382.015, 382.016, 382.017 and 382.021.

§112.300. Applicability.

(a) The requirements in this subchapter apply to affected sources at the Arcosa LWS LLC Lightweight Streetman plant ~~site~~, which is located at 14885 South Interstate Highway 45 East in Streetman, Texas ~~(Regulated Entity Number (RN) RN100211283)~~ in the Navarro County sulfur dioxide (SO_2) nonattainment area. Affected sources will remain subject to this subchapter regardless of ownership, operational control, or other documentation changes. ~~Once approved by the United States Environmental Protection Agency (EPA), the requirements in section continue to apply until the EPA approves their removal.~~

(b) The affected source is designated by source name and emission point number (EPN) ~~and source name~~ used in the site's New Source Review (NSR) permit as issued on the specified date. The affected source is ~~EPN E3-1,~~ Kiln Scrubber Stack (EPN E3-1)~~,~~ in New Source Review Permit 5337 dated May 29, 2020. This designation must continue to be used as the EPN for the lightweight aggregate kiln or any control device for SO_2 regardless of any changes made to the lightweight aggregate kiln or its control system.

§112.301. Definitions.

Unless specifically defined in the Texas Clean Air Act (Texas Health and Safety Code, Chapter 382), or in §101.1 or §112.1 of this title (relating to Definitions, respectively), the terms in this subchapter have the meanings commonly used in the field of air pollution control. The following meanings apply in this subchapter unless the context clearly indicates otherwise.

(1) Continuous Monitoring--Monitoring for which readings are recorded at least once every 15 minutes.

(2) ~~(1)~~ Lightweight aggregate kiln--A rotary kiln used to produce lightweight aggregate material. Any calciner or other associated devices used with the kiln for production are included as part of the kiln.

(3) ~~(2)~~ Lightweight aggregate material--A manufactured aggregate produced by expanding or pelletizing shale, clay, or slate in a rotary kiln that meets the standards of ASTM Cl25, ASTM C330, and/or other similar industry association standards and definitions. ~~Minerals, rock materials, rock-like products, and byproducts of manufacturing processes, which are used as bulk fillers in lightweight structural concrete, concrete building blocks, precast structural units, road surfacing materials, plaster aggregates, and insulating fill, or other similar materials~~

(4) ~~(3)~~ Navarro County sulfur dioxide (SO_2) nonattainment area--The portion of Navarro County designated by the United States Environmental Protection Agency (EPA) as nonattainment for the 2010 SO_2 National Ambient Air Quality Standard, 40 Code of Federal Regulations §81.344~~, as published on March 26, 2021 (86 *Federal Register* 16055), effective April 30, 2021~~.

~~(4) Pipeline quality natural gas--Natural gas containing no more than 0.25 grain of hydrogen sulfide and 5 grains of total sulfur per 100 dry standard cubic feet.~~

§112.302. Control Requirements.

~~(a) The owner or operator may not change the Regulated Entity Number (RN) or the emission point number (EPN) designation of a source subject to §112.300 of this title (relating to Applicability) or otherwise contravene any of the control requirements in this section without the prior approval of the executive director and the United~~

~~States Environmental Protection Agency (EPA).~~

(a) ~~(b)~~ The ~~EPN E3-1 (~~Kiln Scrubber Stack (EPN E3-1) and the associated lightweight aggregate kiln must emit all exhaust gases through a stack that is at least 36.576 ~~35.052~~ meters tall and must be located within a rectangle designated as having its corners at Universal Transverse Mercator (UTM) coordinates UTM East Meters 750646.0 ~~750666.0~~ and UTM North Meters 3533975.0, UTM East Meters 750676.0 and UTM North Meters 3533975.0, UTM East Meters 750646.0 and UTM North Meters 3533955.0, and UTM East Meters 750676.0 and UTM North Meters 3533955.0,~~3533945.0~~ in UTM Zone 14. A bypass to the lightweight aggregate kiln or its control device may not be installed unless it vents through this stack.

(b) ~~(c)~~ Emissions from the ~~EPN E3-1 (~~Kiln Scrubber Stack (EPN E3-1) ~~and lightweight aggregate kiln~~ may not exceed 222.00 ~~248.00~~ pounds per hour (lb/hr) sulfur dioxide ~~(SO_2), except as provided for in subsection (d) of this section,~~ the temperature of the exhaust gas exiting from the stack may not fall below 117 ~~125~~ degrees Fahrenheit, and the velocity of the exhaust gas exiting from the stack may not drop below 42.5 ~~65~~ feet per second ~~(ft/s)~~.

~~(d) If the stack temperature is at least 150 degrees Fahrenheit and the exhaust velocity is 66 ft/s or greater, emissions from EPN E3-1 (Kiln Scrubber Stack) and lightweight aggregate kiln may not exceed 283.00 lb/hr SO_2.~~

~~(e) The fuel used in the lightweight aggregate kiln must be coal or petroleum coke for which the sulfur content is determined as specified in §112.303 of this title (relating to Monitoring Requirements), pipeline quality natural gas, or a combination of these fuels.~~

~~(f) The total sulfur content of all fuel burned in the lightweight aggregate kiln may not exceed 200.00 lb/hr.~~

(c)~~(g)~~ The owner or operator may request an alternate means of control (AMOC) as follows: ~~alternative SO_2 emission limit if dispersion modeling and analysis consistent with the most recent attainment demonstration confirms the alternative limit will not increase the modeled regulatory design value in the nonattainment area. The alternative limit and any deviations from the modeling methodology from the most recent attainment demonstration must be approved by the executive director and the EPA.~~

(1) Permitting Requirements. Compliance with this subsection does not relieve any owner or operator of the responsibility to comply with the requirements of §116.110 or §116.151 of this title (relating to Applicability and New Major Source or Major Modification in Nonattainment Area Other Than Ozone, respectively) with respect to the new construction or modification of sources that may emit SO_2 into the air of this state.

(2) Availability of AMOC.

(A) The owner or operator of any site subject to a control requirement in this subchapter may request approval of an AMOC plan using the procedures established in this subsection. The executive director shall review a submitted AMOC and may approve the AMOC plan if it is demonstrated that the plan meets all applicable criteria and procedures of this subsection. The owner or operator who submits an AMOC plan not satisfying the requirements of this section may apply for a site-specific state implementation plan revision approved by the executive director and the United States Environmental Protection Agency (EPA).

(B) An AMOC applicant may apply to the executive director for a waiver of portions of paragraphs (5) and (6) of this subsection.

(C) Application for an AMOC plan does not stay enforcement of regulations in this subchapter.

(D) Any violation of an AMOC plan will be subject to enforcement action as a violation of this subchapter.

(3) Criteria for Approval of AMOC Plans. An AMOC plan may be approved if it meets each of the following criteria, as applicable.

(A) Except as provided for in paragraph (8) of this subsection, all sources covered by the AMOC plan must be and remain at the same site.

(B) If the AMOC plan includes an increase in the lb/hr emission limit for a source subject to the control requirements in this subchapter, the AMOC plan must also include an equivalent decrease in the lb/hr emission limit for one or more sources subject to the control of this subchapter.

(C) The AMOC application must include a demonstration that satisfies the following requirements.

(i) The modeled impacts of all sources affected by the AMOC plan demonstrate no net increase in ground-level concentration, which for purposes of this subparagraph means no net increase in modeled off-property concentration of SO_2, on a highest, first-high basis, at any receptor, *i,* in excess of the lesser of:

(I) $GLC_{crit,i}$, as defined in the following equation; or

Figure 30 TAC §112.302(c)(3)(C)(i)(I)

$$\mathrm{GLC}_{crit,i} = 0.5 \times (196.4\ {}^{\mu g}/{}_{m^3} - DV_{AD,i}) - (DV - DV_{AD,i})$$

Where:

$GLC_{crit,i}$ = The value for each receptor *i* that the modeled concentration in an AMOC demonstration cannot exceed.

$DV_{AD,i}$ = The maximum design value in any modeled scenario approved by the Environmental Protection Agency under 40 Code of Federal Regulations §51.112(a) for receptor *i*; and

DV = The design value specified by the Executive Director under this section, which, on the effective date of this section, equals DVA_o; and may subsequently be no less than DVA_o.

DVA_o = The design value based on the attainment demonstration modeling for the Navarro County SO_2 nonattainment area.

(II) an applicable significant impact level for the one-hour National Ambient Air Quality Standard for SO_2.

(ii) Except where otherwise provided in this subsection, the demonstration required under this paragraph must be by means of applicable air quality models, databases, and other requirements specified in Appendix W to 40 CFR §51.1 and what was used in the modeling for the corresponding SIP revision.

(D) The AMOC must be implemented and reductions created after the effective date of this rule.

(E) The AMOC plan must establish control requirements and monitoring, testing, recordkeeping and reporting requirements consistent with and no less stringent than the applicable requirements of this subchapter for all sources in the plan that render the proposed control requirements enforceable.

(4) Procedures for AMOC Plan Submittal.

(A) The owner or operator requesting an AMOC plan shall submit a proposed AMOC plan and demonstration to the executive director; copies of such plan and demonstration must also be submitted to the appropriate regional office, any local air pollution control program with jurisdiction over the site affected by the AMOC plan, and copies to the EPA regional office.

(B) The proposed AMOC plan must include the following information:

(i) the AMOC applicant name with mailing address, site name with physical address, regulated entity number, and contact person including address and telephone number;

(ii) an identification and a description of the sources involved in the AMOC plan including any applicable air permit numbers, plot plans, detailed flow diagrams, emission point numbers (EPNs), and facility identification numbers (FINs); an identification of the provisions of this subchapter that are applicable to such sources; an identification of promulgated provisions of this subchapter that will be applicable to such sources; and a description of normal operating conditions for each source causing emissions;

(iii) control requirements, which must be established for each source to make emission limits enforceable, to be applicable to each source affected by the proposed AMOC plan;

(iv) a demonstration that the AMOC plan satisfies each applicable requirement of paragraph (3) of this subsection;

(v) a list containing the name, address, and telephone number of any air pollution control program with jurisdiction over the site affected by the AMOC plan; and

(vi) any other relevant information necessary to evaluate the merits and enforceability of the AMOC plan, as may be requested by the executive director.

(C) All representations with regard to the AMOC plan, as well as any provisions attached to the AMOC plan, become conditions upon which the subsequent AMOC plan is issued. If the AMOC plan is approved by the executive director and the EPA, the owner or operator may not vary from such representation or provision if the change will cause a change in the method of control of emissions, the character of the emissions, or will result in an increase in the discharge of the various emissions. If the AMOC plan is approved by the executive director and the EPA, the owner or operator may not vary from the emission limits, control requirements, monitoring, testing, reporting, or recordkeeping requirements of an approved AMOC plan.

(D) Applications to amend or revise an AMOC plan must be submitted subject to the requirements of this subsection.

(5) Procedures for an AMOC Plan Approval. Upon a preliminary determination to approve or deny the proposed AMOC plan, the executive director shall, in writing, so notify the submitter of the plan, any local air pollution control program with jurisdiction over the site affected by the AMOC plan, and the EPA regional office.

(A) If the executive director makes a preliminary determination to approve the AMOC plan, the notice must include a copy of the AMOC plan as preliminarily approved.

(B) If the executive director makes a determination to deny the AMOC plan, the notice must include a description of the reasons for such determination of denial. This determination constitutes a final action of the executive director appealable to the Commission as provided in paragraph (7) of this subsection.

(C) Upon receipt of notice from the executive director that the AMOC plan has received preliminary approval, the AMOC applicant, at the applicant's own expense, shall cause notice of the applicant's intent to obtain an AMOC plan and of the opportunity to submit written comments to be published. The notice must be consistent with paragraph (6) of this subsection.

(D) The executive director shall consider and prepare a written response to all significant and timely written comments filed in connection with an AMOC plan.

(E) In response to the written comments, the executive director may modify the provisions of the AMOC plan, deny the AMOC plan, or approve the AMOC plan without changes.

(F) The executive director shall send written notice of the final determination concerning each AMOC plan to the submitter of the plan, the EPA regional office, any local pollution control program with jurisdiction, and to each person who submitted timely written comments. Such notice must include the final AMOC plan provisions, a copy of the response to comments, and an announcement of the opportunity to appeal the executive director's determination to the Commission. The notice required by this subparagraph must be sent by a means evidencing receipt.

(G) Any person entitled to notice under paragraph (6) of this subsection may, within 15 days of the receipt of such notice, file with the executive director an appeal of the final determination on the AMOC plan. Such appeal may be considered at the next regularly scheduled meeting of the Commission for which adequate notice may be made. Based on arguments submitted to the commission during such appeal, the Commission may remand the AMOC determination to the executive director, deny the AMOC plan, or issue the AMOC plan unchanged.

(H) Within 45 days of final approval of the AMOC plan by the executive director or the Commission for an appeal, the EPA may notify the commission of the EPA's disapproval of the executive director's final decision. Such notification must be in writing and must include a statement of the reason(s) for the disapproval and a specific listing of changes to the AMOC plan needed to overcome the disapproval. Any time prior to the expiration of the 45-day period, the EPA may notify the executive director that no disapproval is forthcoming. Upon receipt of a timely EPA disapproval, the executive director shall void or revise the AMOC plan and reissue the notice as required by paragraph (6) of this subsection.

(I) If no appeal of the executive director's decision to approve the AMOC plan is filed pursuant to paragraph (8) of this subsection, the AMOC plan becomes effective upon the acceptance of the plan by the EPA as described in subparagraph (K) of this paragraph.

(J) If an appeal of the executive director's decision is filed, the AMOC plan becomes effective upon the latter of the acceptance of the AMOC plan by the Commission or the acceptance of the AMOC plan by the EPA.

(K) EPA acceptance is defined as explicit approval of the AMOC plan by the EPA, notification by the EPA to the executive director that no EPA disapproval is forthcoming, or failure of the EPA to file notice of disapproval within 45 days after the executive director's final decision to approve the AMOC plan.

(6) Public Notice Format.

(A) Public notice must be published in the public notice section of two successive issues of a newspaper of general circulation in or closest to the municipality in which the site affected by the AMOC plan is located.

(B) Public notice must contain the following information:

(i) the AMOC plan application number assigned by the executive director;

(ii) the AMOC applicant's name;

(iii) the type of source and site;

(iv) a description of the location of the site;

(v) a brief description of the AMOC plan;

(vi) the executive director's preliminary determination to approve the plan;

(vii) the locations and availability of copies of the proposed AMOC plan, related documentation, and the executive director's preliminary analysis of the plan (including the Austin and appropriate regional offices, any local pollution control program with jurisdiction over the site affected by the AMOC plan, and the EPA regional office);

(viii) an announcement of the opportunity to submit written comments on the AMOC plan;

(ix) the length of the public comment period, which extends to at least 30 days after the final publication of the notice;

(x) the procedure for submission of written public comments concerning the proposed AMOC plan; and

(xi) the name, address, and phone number of the Agency's regional office to be contacted for further information.

(C) The executive director may not take final action on the AMOC plan until the owner or operator who submitted the AMOC plan has provided proof of adequate notice to the executive director, the EPA, and any local pollution control program with jurisdiction.

(7) Review of Approved AMOC Plans and Termination of AMOC Plans.

(A) For the purposes of this subsection, compliance date means the date by which a source must comply with new or modified sections of this subchapter.

(B) Unless revised to reflect new regulatory requirements, an AMOC plan becomes void on the compliance date specified for a new or modified section of this subchapter affecting a source subject to an AMOC plan.

(C) The holder of an AMOC plan shall comply with the requirements of this subchapter if the AMOC plan becomes void.

(D) Upon final approval of an AMOC plan, the owner or operator of the sources affected by the plan shall keep a copy of the plan on the site affected by the plan and shall make the plan available upon request to representatives of the executive director, the EPA, or any local air pollution control agency having jurisdiction in the area.

(E) Upon request, each holder of an AMOC plan shall submit to the executive director a demonstration that the plan continues to meet all applicable criteria of this subsection.

(F) An AMOC holder is responsible for obtaining a new AMOC plan prior to the compliance date of any new or modified regulation of this subchapter that affects a source subject to an AMOC plan.

(8) Inclusion of Contiguous Properties. Notwithstanding paragraph (3)(A) of this subsection, an AMOC plan may cover multiple sources operated on contiguous properties, provided that separate requests for plan approval are submitted by each owner or operator subject to a control requirement under this subchapter.

§112.303. Monitoring Requirements.

The owner or operator shall install, operate, calibrate, and maintain a continuous emissions monitoring system (CEMS) according to the manufacturer's specifications to continuously monitor the sulfur dioxide (SO_2) emissions ~~following parameters of the lightweight aggregate kiln~~ in accordance with the requirements of 40 CFR §60.13, 40 CFR 60, Appendix B, Performance Specification 2 and 6, for SO_2, and Appendix F, quality assurance procedures. ~~, the fuels combusted, and the raw materials treated in the kiln:~~

(1) monitor the pounds per hour of SO_2 emitted from Kiln Scrubber Stack (EPN E-3) ~~the amount of shale and any other raw material processed each hour;~~

~~(2) the amount of each type of fuel used during each hour;~~

~~(3) the total sulfur content of the natural gas at least monthly; an analysis provided by the supplier of the natural gas is sufficient for this monitoring requirement;~~

~~(4) the average sulfur content of coal and petroleum coke combusted each week; an analysis provided by the supplier of the coal or petroleum coke is sufficient for this monitoring requirement;~~

~~(5) the average total sulfur content of the shale and any other raw material processed each week from all sources; for any raw material supplied from a source not affiliated with the owner or operator, an analysis provided by the supplier of a raw material is sufficient for this monitoring requirement;~~

(2) ~~(6)~~ monitor continuously ~~continuous monitoring of~~ the temperature and velocity of exhaust gases at ~~the outlet after the control device, if installed, or at~~ the outlet of the stack ~~from the kiln or any bypass, if present~~; and

(3) ~~(7)~~ provide ~~continuous monitoring data collected in accordance with requirements in this subsection must undergo~~ an appropriate quality assurance and quality control process for all continuous monitoring data collected in accordance with requirements in this subsection that is ~~and be~~ validated for at least 95% of the time that the monitored emission source operates; an owner or operator must utilize an appropriate data substitution process based on the most accurate methodology available, which is at least equivalent to engineering judgement, to obtain all missing or invalidated monitoring data for the remaining period the monitored source is in operation.

(4) Minor modifications to monitoring methods may be approved by the executive director. Monitoring methods other than those specified in this section may be used if approved by the executive director and validated by 40 CFR Part 63, Appendix A, Test Method 301. For the purposes of this subsection, substitute "executive director" in each place that Test Method 301 references "administrator." These validation procedures may be waived by the executive director or a different protocol may be granted for site-specific applications. Minor modifications that may be approved under this subsection include increases in the frequency of monitoring and the replacement of parametric monitoring with direct emissions monitoring with a CEMS provided appropriate quality assurance control, accuracy specifications, and data validation requirements are specified and no less stringent than monitoring requirements for a comparable EPN in this division.

§112.304. Testing Requirements.

(a) Within 60 days of installation of a continuous emissions monitoring system (CEMS) ~~By the compliance date in §112.308 of this title (relating to Compliance Schedules)~~, the owner or operator shall conduct a performance ~~stack~~ test to determine the current emission rate from the lightweight aggregate kiln to be used in calibrating the CEMS~~, unless testing in subsection (b) of this section has been conducted~~.

~~(b) After installation of any control device for sulfur dioxide on or after the effective date of this rule, the owner or operator shall conduct a stack test to determine the control efficiency of the control device within 60 days of installation.~~

~~(c) If the kiln or the control device is modified after the compliance date, including but not limited to addition of a control device, or if there is a change of the raw material used, the owner or operator shall conduct a stack test within 60 days.~~

~~(d) Any stack test conducted under subsections (a) – (c) of this section must be conducted while the lightweight aggregate kiln is operating at full load and while raw material and fuels with the maximum anticipated sulfur content are in use.~~

~~(e) When analysis of fuels is required for monitoring under §112.303 of this title (relating to Monitoring Requirements), the owner or operator shall use a test method in §112.305(c) of this title (relating to Approved Test Methods) for the analysis.~~

~~(f) The owner or operator shall analyze the shale and any other raw material treated in the lightweight aggregate kiln using a method suitable for the specific material. Prior to the initial use of each test method, the owner or operator shall submit the test method to the executive director and receive approval for its use for the specific raw material.~~

(b) ~~(g)~~ The owner or operator shall conduct additional performance testing, if requested by the executive director. All performance tests must be conducted using test methods allowed in §112.305 of this title.

§112.305. Approved Test Methods.

(a) The initial performance test after installation of the continuous emissions monitoring system (CEMS) for sulfur ~~Sulfur~~ dioxide ~~(SO_2)~~ in exhaust gases and the relative accuracy test audits required by 40 Code of Federal Regulations (CFR) Part 60, Appendix F must be conducted ~~determined~~ using United States Environmental Protection Agency (EPA) Test Method 6 or 6C (40 ~~Code of Federal Regulations (CFR),~~ Part 60, Appendix A).

(b) Performance ~~Stack~~ tests and relative accuracy test audits must be conducted using a method in subsection (a) and EPA Test Method 2 (40 CFR Part 60, Appendix A) for exhaust gas flow and following the measurement site criteria of EPA Test Method 1,

§11.1 (40 CFR Part 60, Appendix A), or EPA Test Method 19 (40 CFR Part 60, Appendix A) for exhaust gas flow in conjunction with the measurement site criteria of Performance Specification 2, §8.1.3 (40 CFR Part 60, Appendix B).

~~(c) Sulfur content of fuels must be determined using American Society for Testing and Materials (ASTM) Method D1945-91 or ASTM Method D3588-93 for fuel composition.~~

~~(d) Sulfur content of shale and other raw materials processed in the lightweight aggregate kiln must be tested using a method approved by the executive director.~~

(c) ~~(e)~~ Alternate methods as approved by the executive director and the EPA may be used.

§112.306. Recordkeeping Requirements.

The owner or operator shall maintain, for a minimum of five years, records in written or electronic format sufficient to demonstrate compliance with all applicable requirements in this subchapter, including but not limited to:

~~(1) hourly records of the amount of each fuel used;~~

~~(2) records of the results of each monthly analysis of the natural gas~~

~~used;~~

~~(3) records of the results of each weekly analysis of the coal and of the petroleum coke combusted;~~

~~(4) hourly records of the amounts of shale and other raw materials processed in the lightweight aggregate kiln;~~

(1) ~~(5)~~ records of the continuous monitoring of exhaust gas sulfur content, temperature and velocity from the appropriate stack ~~stack(s)~~;

~~(6) records of calculations of the sulfur content of all fuels combusted and raw materials processed each hour, which are calculated by multiplying the sulfur content of each fuel or raw material by the amount consumed in an hour and summing the results for all materials;~~

~~(7) records of mass balance calculations of the amounts of sulfur emitted on an hourly basis, which is calculated by multiplying the summed sulfur contents in paragraph (6) of this subsection by two to convert the weight of sulfur to the weight of sulfur dioxide;~~

(2) ~~(8)~~ documentation of any period that ~~records of any exceedance of the sulfur dioxide~~ emission limits or standards were exceeded, and copies of exceedance

reports submitted to the appropriate Texas Commission on Environmental Quality regional office ~~or the stack parameters associated with an emission limit in §112.302 of this title (relating to Control Requirements)~~; and

(3) ~~(9)~~ a copy of each performance ~~stack~~ test and relative accuracy test audit conducted and associated records.

§112.307. Reporting Requirements.

(a) If an affected source exceeds the applicable emission limit or fails to meet a required stack parameter, the owner or operator shall submit to the Texas Commission on Environmental Quality (TCEQ) Regional Office for the area where the plant is located a report by March 31 of the year after an exceedance occurs documenting the excess emissions during the preceding calendar year, including at least the following:

(1) the date that each exceedance or failure to meet a required stack parameter occurred;

(2) an explanation of the exceedance or failure to meet a required stack parameter;

(3) a statement of whether the exceedance or failure to meet a required stack parameter was concurrent with an authorized maintenance, startup, or shutdown

~~MSS~~ activity for, or malfunction of, an affected source ~~facility~~ or control system;

(4) a description of the action taken, if any; and

(5) a written statement, signed by the owner or operator, certifying the accuracy and completeness of the information contained in the report.

(b) The owner or operator shall submit a copy of each performance ~~stack~~ test report to the TCEQ Regional Office and any local air pollution control agency having jurisdiction for the area where the plant is located within 60 days after completion of the test.

(c) After the effective date of a determination by the United States Environmental Protection Agency (EPA) that the Navarro County sulfur dioxide (SO_2) nonattainment area has failed to attain the 2010 one-hour SO_2 National Ambient Air Quality Standard or failed to meet reasonable further progress (RFP) pursuant to federal ~~Federal~~ Clean Air Act §179(c), 42 United States Code §7509(c), the TCEQ will notify the owner or operator of the failure to attain and that the contingency measures in this subsection are triggered. Once notification is received from the TCEQ, the owner or operator shall perform a full system audit (FSA) of the SO_2 sources subject to §112.300 of this title (relating to Applicability).

(1) Within 90 calendar days after the date of the notification, the owner

or operator shall submit the FSA, including recommended provisional SO_2 emission control strategies as necessary, to the executive director of the TCEQ.

(2) As part of the FSA, the owner or operator shall conduct a root cause analysis of the circumstances surrounding the cause of the determination of failure to attain or failure to meet RFP, including a review and consideration of the following:

(A) for all causes of the determination of failure to attain or failure to meet RFP, at a minimum, hourly mass emissions of SO_2 from each SO_2 source subject to this division; and

(B) for a determination of failure to attain based on ambient air monitor data or modeling data, at a minimum, the meteorological conditions recorded at the monitor or other relevant meteorological data, including the frequency distribution of wind direction temporally correlated with SO_2 readings greater than 75 parts per billion at the monitor for which the EPA's determination of failure to attain was made; and any emissions ~~exceptional~~ event that may have occurred. The root cause analysis and associated records used to conduct the audit must consider information on the days that monitored exceedances occurred during the time period that the EPA evaluated in making the failure to attain determination.

§112.308. Compliance Schedules.

The owner or operator of the Arcosa LWS LLC Lightweight Streetman plant ~~site (Regulated Entity Number 100211283)~~ shall comply with the requirements of this subchapter ~~as soon as practicable, but~~ no later than January 1, 2025.