# Exhibit Q. CARB, Review of the San Joaquin Valley Air Pollution Control District Emission Reduction Credit System (2020)

# Review of the San Joaquin Valley Air Pollution Control District Emission Reduction Credit System

June 2020

Enforcement Division
California Air Resources Board

## Executive Summary

On January 24th, 2019, the California Air Resources Board (CARB) directed staff to conduct a review of the San Joaquin Valley Air Pollution Control District (SJVAPCD or District) Emission Reduction Credit (ERC) program. This report provides our analysis, results, findings, and recommendations. The goal of this project was to review the SJVAPCD ERC system, including the equivalency determination, and explain it in the context of the broader District program for reducing emissions from stationary sources including New Source Review (NSR), permitting, and regulatory requirements.

CARB staff has shared the findings of its review with the District management and discussed with the District leadership the need to update the Districts ERC program and processes to address the following overarching findings.

- The program needs to be more transparent to the public and industry and more rigorous.
- Implementation procedures and policies need to be upgraded.
- Assumptions in the equivalency demonstration need to be reviewed and revised as needed.

In response to these overarching findings, the District has committed to take the following specific steps.

- Develop a new equivalency tracking database, including associated documentation.
- Conduct a public workshop each year, beginning with the 2020 equivalency demonstration, to present the results of the annual equivalency demonstration prior to taking the report to the District's Governing Board.
- Enhance the annual demonstration report to make the report more understandable beginning with the 2020 equivalency demonstration, including more fully characterizing adjustments made to year-to-year carry-overs to ensure the public can better understand all adjustments effective in a tracking year.
- Convene a public advisory working group consisting of affected stakeholders, including regulated Valley businesses, Valley residents, and federal, state, and local public agencies, to assist in developing solutions related to the District's offset equivalency system, as needed to maintain an effective permitting system that allows for strong economic growth and protection of public health.
- Adjust calculated emission reductions from all affected AG-ICE projects to reflect the appropriate load-factor, and incorporate these adjustments into the 2020 equivalency demonstration. The District will include a discussion of the analysis and adjustments in the 2020 report.

- Analyze the orphan shutdowns projects identified by CARB, and make adjustments, as appropriate, for inclusion in the 2020 equivalency demonstration. The District will include a discussion of the analysis and adjustments in the 2020 report.
- Update the District's policies that pertain to the quantification of emissions reductions from orphan shutdowns, and ensure procedures and associated staff training maintain consistency with District NSR criteria for creditability of emissions reductions.

CARB staff plans to work with the district as it implements the above commitments as well as periodically update its Board on progress.

The SJVAPCD was formed in 1992 by the unification of eight individual county districts. Prior to unification, each county had independent rules and requirements, and made their own permitting decisions. With unification, the District developed a single set of rules and regulations, including those governing its NSR and ERC programs. While new ERCs issued after unification were developed in a consistent manner, older ERCs generated prior to unification needed to be carried over. These ERCs exist today and may be available to offset new emissions. About half of all NOx and VOC ERCs were generated prior to unification.

The District adopted its NSR rule in 1991. The rule established BACT requirements, offset thresholds, and offset requirements that when originally put in place applied to more sources, and applied a much greater level of stringency to those sources than required under federal and state law. The rule also diverged from federal requirements in one important respect: under the District rules, the value of an ERC is calculated when the ERC is issued and retains this value over the life of the ERC. This is referred to as "time of issuance" value, and was supported by CARB at the time.

Federal law requires an ERC to be valued at time-of-use, meaning that if a regulation would have reduced emissions from a source granted an ERC, that ERC must be discounted when used as an offset to reflect emissions after required controls from the regulation. The value of an ERC will always be the same or lower at time-of-use than time of issuance. The federal Clean Air Act allows local NSR programs to differ from federal NSR so long as the local program is at least as stringent as federal NSR. In order to demonstrate that the District's NSR program is at least as stringent as federal NSR, in 1999 U.S. EPA and SJVAPCD entered into an agreement requiring the District to implement an annual federal offset equivalency tracking system. U.S. EPA required this agreement as a condition of approving the District's amended NSR rule for incorporation into the State Implementation Plan.

From the time the tracking system was adopted in August 2001 until present, SJVAPCD has never failed to show equivalency based on its annual demonstration to U.S. EPA. However, in 2010, the San Joaquin Valley's federal non-attainment ozone

classification was bumped up from severe to extreme. As a result, the federal major source and major modification thresholds for ozone precursors dropped to levels that were equivalent to emissions thresholds established in the District's NSR rule. This effectively eliminated the primary advantage SJVAPCD's NSR program had in offset stringency over the federal NSR program for NOx, VOC, and CO. Once the District's offset threshold was no longer lower than the federally required threshold, in most cases more offsets are required for major sources under federal requirements than under District rules.

The current SJVAPCD ERC bank contains nearly 11 million pounds per year of NOx ERCs when valued at time of issuance, more than 80% of which were generated more than 20 years ago. However, over the years, the District's regulatory program has become more stringent, and the District estimated in 2016 that these NOx ERCs, when valued at time-of-use, were worth about 18% of the time of issuance value. This reduction in time of issuance value is directly related to the stringency of the District's regulatory program. In effect, as the District increases the stringency in its regulatory program, it also reduces the time-of-use value in its ERC bank, which makes achieving equivalency more difficult.

To demonstrate equivalency, the District has been increasingly relying on the carry-over of past mitigations and reductions, including past unbanked reductions from orphan shutdowns and electrification projects. These emission reductions are not generated as part of the ERC system, but are used to demonstrate offset equivalency between the District program and federal requirements. Between 2010 and 2018, half of all VOC reductions, and 75% of all NOx reductions included in the District's equivalency demonstrations were provided by orphan shutdowns and electrification projects, with the remaining value provided by ERCs.

CARB's review identifies three areas of findings. First, many of the District's engineering evaluations of ERC and permit applications, and the District's equivalency database system, can both be more transparent, and rigorous. These documents could be improved by including supporting explanation or documentation. Without this information, the public and industry cannot verify or fully review the District's actions. Staff also identified calculation discrepancies in electrification projects and orphan[1] shutdowns used for offset equivalency. These issues could be avoided through stronger review procedures.

Second, the District should make adjustments to how it implements its rule for the timeliness of ERC application submittals, and could be more rigorous in its determination of surplus reductions in individual ERCs. For example, in 15 of the 52 ERC projects reviewed, the District granted ERCs, generated by facility shutdowns, in

[1] Orphan shutdowns are unclaimed emission reductions from a facility surrendering all their operating permits.

which emissions ceased more than 180 days before submission of the ERC application. This is consistent with the District's long-standing policy, CARB staff interpret the District's rule as requiring an ERC application to be submitted within 180 days of the shutdown, and that it defines shutdown as the earlier of the permanent cessation of emissions, or the surrender of the operating permit. In addition, in four of the 52 ERC projects reviewed, CARB determined that it is unclear whether the emission reductions were surplus of every federal, State, or district law, rule, order, permit, or regulation. This benefitted the applicant by providing a greater face value to the ERC. But, as a result, the District had to find additional reductions to cover the non-surplus ERCs.

In the third set of findings, staff identified issues in the District's equivalency demonstration. The District relies on electrification projects, generated through the Agricultural Internal Combustion Engine (AG-ICE) incentive program, to demonstrate NOx equivalency with federal requirements. In calculating and claiming credit for these projects, the District used an incorrect load factor, resulting in an overvaluing of reductions in the equivalency demonstration. While the reductions are real, they were not sufficiently documented to have resulted from a permitting action nor could CARB staff identify documentation showing that they were permanent and enforceable. CARB staff also concluded that potentially half of the credited projects appeared to be funded in part through the Carl Moyer program.

The issues identified in this report are substantial and complex, potentially impacting a wide array of stakeholders in the San Joaquin Valley including residents of the Valley, industries that rely on offsets and ERCs in order to expand or build new business, environmental organizations who advocate for cleaner air, and community groups representing those living near stationary and mobile sources who are impacted the most by emissions at the local level.

The Valley has always faced substantial air quality challenges due to its geography, meteorology, and climate. The SJVAPCD has over 150 rules applicable to specific types of equipment (e.g., turbines, internal combustion engines, boilers), to specific industries (e.g., confined animal facilities, oil production, composting), and to all sources (e.g., nuisance, visible emissions). As technologies have improved, the District has continued to improve the stringency of its regulations. The Valley's stationary source emissions have been reduced because of source-specific regulations and now represent 15% of total NOx emissions in the Valley. Despite these successes, the San Joaquin Valley continues to face major air quality challenges. Air pollution concentrations of ozone and particulate are often above standards, and the District continues to experience some of the worst air quality in the United States. Further improvements in air quality will require both stationary and mobile source emissions to be minimized.

Many of the findings in this report - regarding the issuance of individual ERCs, the time of issuance valuation of ERCs, the use of electrification projects from the AG-ICE program, and others - relate to decisions made decades ago. Since these decisions were made, conditions have changed. Air quality has improved substantially, but ambient air quality standards have increased in stringency. Even though these decisions were made decades ago, they generate implications for air quality today. Consistent with the staff recommendations as well as the District commitments the primary focus of this report is on improvements to the district's ERC program moving forward. This report identifies potential improvements in the District's ERC program, which will help in ensuring an effective permitting program that protects public health and supports economic growth and development, which in turn strengthens the District's overall regulatory program.

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

June 4, 2020

Richard Corey, Executive Officer
California Air Resources Board
P.O. Box 2815
Sacramento, California 95812

**Re: California Air Resource Board's Review of San Joaquin Valley Air Pollution Control District Emission Reduction Credit System**

Dear Mr. Corey,

The San Joaquin Valley Air Pollution Control District (District) has received the California Air Resources Board's (CARB) report titled *Review of San Joaquin Valley Air Pollution Control District Emission Reduction Credit System.* The District staff would like to thank CARB for the opportunity to review and comment on the recommendations of this review. District staff and CARB have worked cooperatively over the past year-and-a-half during this review to evaluate the District's Emission Reduction Credit (ERC) program and identify opportunities to enhance the District's ERC program moving forward in a manner that will help to ensure an effective permitting program that protects public health and supports economic growth and development in the Valley. Furthermore, the District is committed to working closely and collaboratively with CARB and Valley stakeholders to address the recommendations in the report and implement the District's commitments contained in this letter. Additionally, the District is appreciative of CARB's general recognition of the stringency of the District's air quality control program and of the success in reducing stationary source emissions in the Valley.

Both federal and state law mandate New and Modified Stationary Source Review (NSR) permitting programs that contain offsetting and ERC banking provisions. ERCs are intended by both federal and state law to be only one part of a comprehensive NSR permitting program that has been specifically designed by Congress and the state legislature to allow for industrial growth while tightly regulating any emissions increases. Additionally, any emission increases due to growth are accounted for in State Implementation Plans that demonstrate how the District's overall air quality control program will require sufficient emissions reductions to attain national ambient air quality standards, despite that growth.

While it is mentioned in the report, the District feels that it is important to reiterate that, despite a seemingly common misconception, ERCs cannot be used in lieu of meeting

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other air pollution control requirements, such as through market-based systems that other agencies may have in place. Instead, ERCs are required in addition to, and only after, establishing that the new emissions are controlled with the best available control technology (BACT) and will not cause a health risk to surrounding communities. The San Joaquin Valley's NSR permitting program, including the accompanying ERC program, ensures that new emissions are controlled with the best technologies, prevents the permitting of any operation that will cause a significant health impact, demonstrates on a project-by-project basis and in each attainment plan that attainment is not endangered, and has historically been found by the state and federal governments to comply with state and federal laws governing NSR/ERC programs.

Businesses can only generate ERCs by voluntarily reducing emissions to levels below those required by any rule or regulation, and then applying to the District to have those reductions recognized in the form of an ERC banking certificate. Because the District's air quality regulations are among the most stringent requirements in the nation, it is exceedingly difficult and expensive for businesses to reduce emissions beyond rule requirements to generate ERCs. In fact, as more effective controls are developed, they are generally required through regulatory action by the District, limiting the time that new and innovative techniques can be used to generate ERCs. Reductions beyond the level required by those regulations generally involve innovative or untested control techniques, which entail considerable financial risk to develop and implement. The opportunity to bank ERCs for reductions that result from these types of extraordinary and voluntary efforts, and then to be able to sell them on the open market, encourages innovation in emissions control technologies.

The difficulty in the ability to generate and rely on new ERCs for future permitting projects underscores the challenges faced by businesses, especially in extreme ozone non-attainment areas, which even after installing the best available control technology must still provide ERCs to offset emission increases. Without sufficient ERCs, new and modifying businesses and essential public services including, but not limited to, hospitals, waste-water treatment facilities, and composting facilities may not be able to obtain necessary operating permits to serve Valley communities.

While the District and CARB agree on many of the areas identified in the report and on a general path moving forward, there are areas where the District and CARB have differing opinions, especially as it relates to the interpretation and application of certain provisions of District rules and regulations as they pertain to the ERC program. This is not uncommon in a review of this complexity and scale, and the District does not believe that these points of contention undermine the overall cooperative process and ultimate agreement by CARB and the District on a path to move forward relying on the recommendations of CARB and commitments by the District.

In completing this comprehensive review, CARB reached three overarching findings to which the District will respond in turn. The findings as detailed in the report are as follows:

- *The [ERC] program needs to be more transparent to the public and industry and more rigorous.*
- *Implementation procedures and policies need to be upgraded.*
- *Assumptions in the equivalency demonstration need to be reviewed and revised as needed.*

***The program needs to be more transparent to the public and industry and more rigorous***

Consistent with the District's core values of continuous improvement and open and transparent public processes, the District respects CARB's recommendations which identify opportunities to enhance transparency as it relates to the District's equivalency database system and specific engineering evaluations of ERC and permit applications. It is important, however, to consider these opportunities in the larger context of the existing transparency measures that the District employs in its permitting program.

For years, the District has provided bilingual notice of all significant proposed permitting projects and ERC transactions on our public website. The complete engineering and compliance evaluations are posted with the associated public notice documentation. Furthermore, any interested parties are provided the opportunity to receive, by email, this same set of documents. They can sign up to receive notices for all projects issued by the District, they can sign up to receive notices for all projects in a specific region of the Valley, or they can sign up to receive all notices associated with an individual facility. Through this process, the public receives direct access to the same exact documents that we send to CARB and EPA for their review. All comments received on the District's preliminary analyses are addressed and responded to in writing before finalizing any ERC issuance or permitting project, and all associated documents, including the District's final analysis and final public notice, are also posted to the District website. Similarly, the District's written analyses and preliminary and final public notices of permitting projects that are required to surrender ERCs to obtain a permit are posted to the District's public website for the same review and comment process.

Specific permitting and ERC projects that have been reviewed contemporaneously by CARB, EPA, and the public without comment on the lack of transparency, are now being highlighted when reviewed under this review. While the District believes that CARB's recommendations highlight opportunities to further enhance transparency, we believe it is important to view the recommendations in a larger context so it is clear they should be interpreted through the lens of continuous improvement.

Regarding the District's equivalency database system and annual offset equivalency report, each year the District makes publicly available the equivalency report and accepts comments on the report and its findings up through the public hearing by the District's Governing Board. Additionally, this report is also sent to U.S. EPA and CARB every year. While we believe that the database and report contain the information necessary to demonstrate that the District's ERC system is equivalent to the federal system, we agree that the database system could benefit from modernization and the annual report could be made more consumable to a reviewer that may not possess a comprehensive understanding of complex NSR and offset equivalency concepts.

***Implementation procedures and policies need to be upgraded***

As recognized in the report, the rules and regulations that implement NSR and ERC banking programs are very complex and require a deep understanding of policy, regulations, and decisions that have been made at the federal, state, and local level over the past 40 years. As a best practice, the District believes that it is prudent to revisit and update, as necessary, policies and procedures that implement District rules and regulations. In the review, CARB questions the District's interpretation of rule provisions relating to the timeliness of ERC applications and the determination of what are considered surplus emission reductions at the time of ERC banking. While the District recognizes the complexity associated with these issues identified in the review, it is important to note that the District has adopted and follows policies and procedures to ensure consistent, fair, and reasonable application of its rules. Furthermore, the areas in question are local requirements of the District's NSR and ERC banking programs, and are beyond any requirements in state or federal law relating to ERCs.

***Assumptions in the equivalency demonstration need to be reviewed and revised as needed***

Consistent with the District's offset equivalency agreement with the federal EPA and with the provisions of the District's NSR rule, the District utilizes the surplus value of emission reductions across various categories to demonstrate equivalency with federal offsetting requirements on an annual basis. As detailed in the report, there was an inconsistency in the District's methodology for calculating emission reductions from agricultural engine electrification projects associated with the AG-ICE program relative to the Moyer methodology. The District is committed to adjusting the calculated emission reductions from all affected AG-ICE projects to reflect the appropriate emission reductions, and incorporate these adjustments into the 2020 equivalency demonstration.

Another category of emission reductions used in equivalency are those from unbanked facility shutdowns ("orphan shutdowns"). Each orphan shutdown

presents a unique set of circumstances that determines the amount of credit that can be claimed. CARB's review identified some inconsistency in the crediting of emission reductions from certain orphan shutdown projects. The District is committed to analyzing the orphan shutdowns projects identified by CARB, and making adjustments, as appropriate, for inclusion in the 2020 equivalency demonstration. Furthermore, District staff intends to review and update as necessary the policies that pertain to the quantification of emissions reductions from orphan shutdowns.

In response to CARB's overarching findings, the District is committed to taking the following specific steps to enhance the ERC program as needed to maintain an effective permitting system that allows for strong economic growth and protection of public health:

- Develop a new equivalency tracking database, including associated documentation.
- Conduct a public workshop each year, beginning with the 2020 equivalency demonstration, to present the results of the annual equivalency demonstration prior to taking the report to the District's Governing Board.
- Enhance the annual demonstration report to make the report more understandable beginning with the 2020 equivalency demonstration, including more fully characterizing adjustments made to year-to-year carry-overs to ensure the public can better understand all adjustments effective in a tracking year.
- Convene a public advisory working group consisting of affected stakeholders, including regulated Valley businesses, Valley residents, and federal, state, and local public agencies, to assist in developing solutions related to the District's offset equivalency system, as needed to maintain an effective permitting system that allows for strong economic growth and protection of public health.
- Adjust calculated emission reductions from all affected AG-ICE projects to reflect the appropriate load-factor, and incorporate these adjustments into the 2020 equivalency demonstration. The District will include a discussion of the analysis and adjustments in the 2020 report.
- Analyze the orphan shutdowns projects identified by CARB, and make adjustments, as appropriate, for inclusion in the 2020 equivalency demonstration. The District will include a discussion of the analysis and adjustments in the 2020 report.
- Update the District's policies that pertain to the quantification of emissions reductions from orphan shutdowns, and ensure procedures and associated staff training maintain consistency with District NSR criteria for creditability of emissions reductions.

As I stated earlier, the District staff is committed to working closely with CARB and Valley stakeholders to address the recommendations collaboratively to ensure an ERC program that serves our shared goals of public health protection and economic viability in the Valley. Please contact me if you have any questions or wish to discuss any of our comments. I can be reached at 559-230-6036 or via email at samir.sheikh@valleyair.org.

Sincerely,



Samir Sheikh
Executive Director/APCO

**List of Acronyms**

AG-ICE – Agricultural Internal Combustion Engine incentive program
AIPE – Adjusted Increase in Permitted Emissions
APCO – Air Pollution Control Officer at an Air District
AQMD – Air Quality Management District
ATC – Authority to Construct
BACT – Best Available Control Technology
CAAQS – California Ambient Air Quality Standards
CARB – California Air Resources Board
CARL – Carl Moyer emissions database
CEMS – Continuous Emissions Monitoring System
CNG – Compressed Natural Gas
CO – Carbon Monoxide
DCF – Discounted Cash Flow
DOQ – District Offset Quantity
EACM – Equivalent Annual Cost Method
ERC – Emission Reduction Credit
FCAA – Federal Clean Air Act
FMM – Federal Major Modification
FOQ – Federal Offset Quantity
GHG – Greenhouse Gas
HAP – Hazardous Air Pollutant
HC – Hydrocarbon
hr – Hour
HSC – California Health and Safety Code
lb – Pounds
MMBTU – Million Metric British Thermal Units
MST – Major Source Threshold
NAAQS – National Ambient Air Quality Standard
NMS – New Major Source
NOx – Nitrogen Oxides
NSR – New Source Review
PAS – San Joaquin Valley's Permit Administration System
PG&E – Pacific Gas and Electric Company

PM10 – Particulate Matter 10 microns in size or smaller
PM2.5 – Particulate Matter 2.5 microns in size or smaller
ppm – Parts per Million
ppmv – Parts per Million by Volume
PTE – Potential to Emit
RACT – Reasonably Available Control Technology
SB 288 – Protect California Air Act of 2003, "NSR anti-backsliding"
SCE – Southern California Edison
SIP – State Implementation Plan
SJVAPCD – San Joaquin Valley Air Pollution Control District
SOx – Sulfur Oxides
t/y – tons per year
U.S. EPA – United States Environmental Protection Agency
VOC – Volatile Organic Compound
yr – Year

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## I. Review Process

CARB conducted this review consistent with State law, including as defined in sections 41500 et seq. of the California Health and Safety Code (HSC). State law defines CARB's important role in reviewing district attainment plans, rules, regulations, and enforcement practices. CARB's role includes programmatic reviews, such as this one, and day-to-day review of individual district actions, such as permits for major sources and major modifications, issuance of ERCs, adoption of rules, and granting of variances.

For the past decade, CARB has reduced its focus on air district stationary source permitting programs due to demands associated with developing, implementing, and enforcing an unprecedented number of mobile source related regulations, many of which focus on reducing emission of diesel particulate matter. As we have implemented these regulations we have also sought to analyze and improve them, including programmatic improvements, regulatory updates, and in some cases new laws to support implementation and enforcement. This iterative approach has generated improvements in both the regulations and implementation. CARB staff is taking a similar approach with stationary sources, re-engaging in district permitting programs and working as a constructive partner with the districts and federal government to ensure existing programs are as successful as possible. In doing so, as evidenced in this review, CARB hopes to provide answers to questions posed by stakeholders and provide assurance that District programs are effective and consistent with underlying regulations.

CARB staff has worked extensively with SJVAPCD staff and executive management to conduct this review. Through data and information requests from CARB, the District provided electronic copies of hundreds of documents related to over 50 ERC projects, 30 Authority to Construct permits, and the federal offset equivalency tracking system. The documents include SJVAPCD and Kern County Air Pollution Control District NSR and banking rules, SJVAPCD policies and guidance documents related to ERC banking, ERC applications and supporting documents related to CARB-selected ERC projects, SJVAPCD engineering evaluations supporting the decision to issue the ERC certificates, and SJVAPCD engineering evaluations and supporting documents related to CARB-selected NSR actions. Information related to Kern County APCD was needed because prior to unification of the San Joaquin Valley Air District in 1991, Kern County had an independent permitting program, which banked a large number of ERCs that were moved over to the unified air district upon unification.

In addition, SJVAPCD provided CARB staff with electronic access to the SJVAPCD Permits Administration System (PAS). PAS is a comprehensive database where all permitting and ERC related actions are recorded and related documents are stored. From PAS, CARB staff retrieved hundreds of documents including permit applications,

engineering evaluations, ERC transaction histories, emission inventories, source test records, and inspection reports related to the original ERC projects under review.

SJVAPCD also provided CARB staff with access to the federal offset equivalency tracking system at District offices. SJVAPCD shared information about the tracking system, access to database files, and tracking system output.

1. *Public Participation*

In November 2018, Earthworks released the report that helped initiate this review -- *Undeserved Credit: Why emissions banking in California's San Joaquin Valley puts air quality at risk*. The Earthworks report made the following findings and conclusions, among others: "a significant proportion of ERCs in the San Joaquin Valley Air Pollution Control District's bank appear to be invalid"; "CARB should audit the San Joaquin Valley Air District ERC system"; "equivalency should be questioned"; and "CARB should not allow ERCs to last forever."

Further, in a January 9, 2019 letter to Mary Nichols, Chairman of the Board, and in testimony at the January 24, 2019 Board Meeting, a coalition of environmental and health advocacy groups representing the Southern San Joaquin Valley requested that CARB "…conduct a thorough review of the Emission Reduction Credit (ERC) banks administered by the San Joaquin Valley Air Pollution Control District…."

CARB staff has considered input from these and other stakeholders in planning and executing this review. CARB staff has also taken steps to ensure this review is an open, public process. Staff held three workshops: in April and September 2019, and in June 2020. During these workshops, staff presented material and solicited comments. These workshops were hosted at the Bakersfield District office, which was linked to the Fresno and Modesto offices by the District's video teleconference system. The workshops were also webcast through CARB's web site, and translation services were made available at all three District office locations.

CARB staff has also had numerous in person meetings and conference calls with stakeholders regarding this project. Staff maintains a website[2] specifically for this project and an email address (valleyERCs@arb.ca.gov) for project questions. The website includes posting of documents related to the current ERC review, past CARB reviews of the District ERC banking program, and ERC banking in general.

2. *Public Stakeholder Concerns*

Stakeholders have identified a number of issues of potential relevance to CARB's review, including the following concerns:

[2]San Joaquin Valley Emission Reduction Credit Program Review, https://ww2.arb.ca.gov/our-work/programs/san-joaquin-valley-emission-reduction-credit-program-review.

- Validity of Older ERCs

Stakeholders have questioned whether certain ERCs were banked in conformance with legal requirements. Some stakeholders believe that the use of older, improperly issued ERCs could result in a large amount of new emissions in the Valley, which could impact local air quality and regional attainment demonstrations. Other stakeholders are concerned the ERCs they hold may be devalued.

- Impacts on Equivalency

Stakeholders have expressed concerns regarding the District's ability to continually identify additional offsets beyond ERCs to account for the difference between time of issuance valuation (as under the District's NSR program) and time-of-use valuation (as under federal NSR) in order to demonstrate equivalency with the federal program. Additional offsets are needed to demonstrate equivalency because the vast majority of ERCs currently in the bank in the San Joaquin Valley appear to have relatively little value at time-of-use. Many times, the value of an ERC has degraded by the time it is used due to more stringent regulations that are adopted or proposed between the time of issuance and time-of-use.

Stakeholders have expressed concern that the use of a large number of older ERCs could result in a failure to demonstrate federal equivalency. At the same time, some stakeholders believe that the use of a large number of older ERCs could result in a large amount of new emissions in the Valley, which could impact local air quality and regional attainment demonstrations.

- No Net-Increase

Under the District program, offsets are required above certain thresholds, but not below those thresholds. Stakeholders have asked whether this maintains the general goal of no-net-increase in emissions from stationary sources.

- Local Air Quality

Under State and federal law, ERCs are a tradeable commodity, and as such allow emissions to increase at one location while decreasing at another location. Some stakeholders have questioned whether emissions trading is appropriate. Further, while districts have rule provisions intended to protect the public from local increases of criteria pollutant and toxics emissions; such as emissions modeling, health risk assessments, and application of BACT; some stakeholders have questioned the effectiveness of these approaches.

- Transparency

NSR programs are quite complicated. While public documents regarding the SJVAPCD NSR program are available upon request, stakeholders have expressed difficulty in accessing relevant information necessary to understand the program. Stakeholders have expressed difficulty in understanding how to formulate and submit

requests for information to meet the District's requirements. This difficulty may be a result of stakeholders not knowing exactly how to specifically identify or describe the information they need to understand the program, or not being able to ascertain the connections and relevance of the provided information in the larger context of the District's NSR program. There appears to be a desire for stakeholders to understand how permitting and NSR works, and the District has indicated it is willing to offer training to stakeholders upon request.

*3. Industry Stakeholder Concerns*

- Availability of ERCs and Economic Growth

Some stakeholders expressed concern over possible "invalidation" of some ERCs, which could have an effect on ERC availability and pricing. Because ERCs are the currency of offsets, and offsets are often needed in order to modify or build a new emissions source, ERCs are critical to on-going economic development in the San Joaquin Valley.

Additionally, stakeholders have expressed concern with the permitting impacts associated with a failure to demonstrate equivalency. More specifically, concerns have been expressed regarding the unavailability of surplus at time-of-use ERCs required under permitting actions for federal new major sources and major modifications, particularly given the low major source thresholds in the San Joaquin Valley and large number of major sources across all sectors.

## II. Part 1: Explaining the Emission Reduction Credit System

### A. Overview of Emission Reduction Credits

The federal Clean Air Act establishes requirements for the permitting of stationary sources. Generally, states have the direct responsibility to meet requirements of the federal Clean Air Act and corresponding federal regulations with respect to permitting. California law, however, allows for delegation of permitting activities to the local and regional air districts. All thirty-five California air districts have taken advantage of the opportunity to implement their own permitting program for stationary sources. In California, maintaining a structure of air districts performing permitting with CARB review has been largely successful. Individual air districts are generally well suited to maintain localized regulations, which has led to improved air quality across the State. CARB has central oversight authority to monitor the performance of district programs and to conduct district functions if the district fails to meet certain responsibilities.

In accordance with the federal Clean Air Act, U.S. EPA sets ambient air quality standards for criteria pollutants. A geographic area that does not meet these standards is called a non-attainment area. The San Joaquin Valley is classified as extreme non-attainment for 8-hour ozone and serious non-attainment for PM2.5. Non-attainment areas must develop State Implementation Plans (SIPs) that either include, or commit to adopt, emission control measures to attain and maintain ambient air quality standards. The local air districts develop and implement portions of the SIP that cover stationary sources through rulemaking, permitting, and enforcement.

Generally, any stationary source that emits or has the potential to emit air pollution is subject to local air district permitting requirements. New or modified sources of air pollution must obtain approval from the local air district in the form of an Authority-to-Construct (ATC) permit. Most ATC permit applications are subject to NSR, and in California NSR is implemented at the district level. The federal Clean Air Act, implementing regulations, and State law establish the minimum requirements for non-attainment NSR permitting programs. U.S. EPA allows implementing authorities to tailor their NSR requirements to address local air quality conditions, provided the local NSR program is at least as stringent as federal standards. Generally speaking, NSR programs require sources exceeding a defined emissions threshold to install best available control technology (BACT) and to offset emission increases which occur after the installation of BACT with emissions reductions. These requirements for mitigating emissions reductions are generally referred to as offsets. NSR programs generally require offsets so that there is no net increase in emissions, on a regional basis, of nonattainment pollutants and their precursors.

NSR rules require either past or contemporaneous emission reductions to be used to counter-balance newly permitted emission increases. Emission reductions above and beyond what is required by rules and regulations, and not immediately used to counter balance new emission increases, can be stored in the form of ERCs. ERCs are the currency of offsets, and are a way of "banking" emission reductions for future use, either at the site they were generated or elsewhere within the air basin (or, in limited circumstances, in a downwind air basin).

Due to the emission-offsetting requirement of NSR, both the federal Clean Air Act and State law require non-attainment areas to have an ERC banking system. To qualify for banking as an ERC, an emission reduction must meet the following criteria:

- Real – the reduction must be in actual emissions not potential, allowed or permitted emissions.
- Quantifiable – the reduction must be calculable based on actual verifiable operational data and the best available emission factors and source test data.
- Surplus – the reduction must go beyond what is required by law, regulation, or SIP commitment at the time the ERC was originally banked.
- Permanent and Enforceable – the reduction must be legally and practically enforceable and permanent through permit conditions and limits, or surrender of the operating permit.

These ERC criteria help ensure the integrity of an ERC program. These criteria are also universal to programs across the United States, and provide the framework CARB staff used in the review of SJVAPCD ERC projects and the equivalency demonstration.

B. Demonstrating Equivalency

The offsetting requirements of the District's NSR rule are different from the offsetting requirements under federal NSR. For example, federal NSR requires offsets from major sources but not from minor sources, whereas the District's NSR rule requires offsets from both major and minor sources if the emissions are calculated to exceed specified offset thresholds. The federal Clean Air Act allows local NSR programs to differ from federal NSR so long as the local program is at least as stringent as federal NSR.

An important caveat to bear in mind when interpreting District and federal offset thresholds is that the District and federal calculation methods that determine "when" offsets are required and "how much" offsets are required are different, especially for modified sources. Thus, even where the pollutant thresholds are the same, the same project will produce different offset quantities for the same pollutant when evaluated under District versus federal NSR.

Other differences exist, which, depending on the facts of a given ATC project, may make either federal NSR or SJVAPCD NSR more stringent regarding offset requirements for a particular project (though the local NSR *program* must remain more stringent overall). Among the most significant difference in offsetting requirements is when the "surplus" value of an ERC is determined. SJVACPD values ERCs at the "time of issuance" whereas federal NSR values ERCs at the "time-of-use."

Specifically, under the SJVAPCD NSR rule, the value of an ERC is calculated when the ERC is issued, and the ERC retains that value throughout its life until it is used. In contrast, under the federal NSR rules, the value of an ERC is calculated first when it is created, and again when it is used. In a 1993 memorandum, entitled "Use of Shutdown Credits for Offsets," U.S. EPA stated that this approach is designed to avoid double counting emission reductions in a SIP. Under the federal approach, each ERC must be re-evaluated based on the rules, regulations, and SIP commitments that apply at the time-of-use. Because many years often elapse between when an ERC is created and when it is used, the adoption of progressively stricter emissions standards can cause the surplus value of an ERC to drop significantly.

For example, if a boiler in compliance with all applicable requirements has actual NOx emissions of 30 ppmv and 1.0 ton per year and ceases operation permanently, the operator could apply to bank the resulting NOx emission reductions as an ERC. Following receipt of an application, the air district verifies the reductions are timely, real, surplus, enforceable, permanent, and quantifiable and issues the operator an ERC with a time of issuance or face value of 1.0 tons per year NOx.[3] Suppose 10 years later the owner of this ERC wishes to use it to offset a new permitted emission increase of NOx, and, in the intervening 10 years, the air district has amended its boiler rule to require a NOx standard of 15 ppmv. Under a surplus-at-time-of-use offset system, the portion of the ERC representing a reduction in NOx from 30 to 15 ppmv is no longer surplus, which leaves the portion from 15 to 0 ppmv as the surplus-at-time-of-use value. Thus, the offset value of the ERC is reduced to 0.5 tons per year NOx[4] because half of the NOx emission reductions represented by the ERC are required by the amended boiler rule. However, under a surplus-at-time-of-issuance offset system, the ERC holds it value of 1.0 tons per year in perpetuity even if new rules are subsequently adopted that require stricter emission standards.

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[3] SJVAPCD would deduct 10% for an air quality improvement deduction (AQID); however, the AQID is omitted in this example for demonstration purposes.

[4] Discount Percentage = [(EF1 – Rule EF) ÷ (EF1 – EF2)] = [(30 – 15) ÷ (15 – 0)] = 0.50
ERC Surplus Value = (Current ERC Value) x (1 – Discount Percentage) = 1 tons per year x (1.0 – 0.50) = 0.5 tons per year
Where: EF1 = Pre-project emission factor used to calculate AER from the original banking action
EF2 = Post project emission factor used to calculate AER from the original banking action
EF Rule = Current emission factor required by a rule or regulation
Source: SJVAPCD Draft Staff Report Annual Offset Equivalency Demonstration (April 19, 2016).

Due to the differences between the federal and District NSR programs, in 1999 U.S. EPA and SJVAPCD entered into an agreement requiring SJVAPCD to implement an annual federal offset equivalency tracking system. U.S. EPA required this agreement as a condition of approving SJVAPCD's amended NSR rule for incorporation into the SIP. The purpose of the equivalency tracking system is to show, on a program-wide basis, that SJVAPCD's NSR rule requires an equal or greater amount of offsets than would be required under the terms of federal NSR. Equivalency is tracked on a pollutant-by-pollutant basis for each of the District's non-attainment pollutants. The District issues an annual offset equivalency report to U.S. EPA. The report is based on the outputs from the District's internal equivalency system.

From the time the tracking system was adopted in August 2001 until present, SJVAPCD has never failed to show equivalency in its annual demonstration report submitted to U.S. EPA. As a result, SJVAPCD has been able to maintain its offsetting system instead of adopting federal offset requirements for new major sources (NMS) and federal major modifications (FMM) to existing major sources. If SJVAPCD were to fail to show equivalency, they would be required, by their existing NSR rule and the agreement with U.S. EPA, to follow federal offsetting standards, including valuing ERCs at time-of-use rather than at time-of-issuance.

C. Role of ERCs under the Federal Clean Air Act

The federal Clean Air Act (FCAA) forms the basis for the national air pollution control effort, including among other elements, national ambient air quality standards for major air pollutants, hazardous air pollutants standards, state attainment plans, stationary source emissions standards and permits, and enforcement provisions. Both the federal government (under the FCAA) and California (under the California Clean Air Act) set air quality standards for clean air. An air quality standard defines the maximum amount of a pollutant averaged over a specified period of time that can be present in outdoor air without harming public health.

The FCAA requires U.S. EPA to set primary National Ambient Air Quality Standards (NAAQS) to protect public health, and secondary NAAQS to protect plants, forests, crops, and materials from damage due to exposure to six air pollutants that are harmful to public health and to the environment. These pollutants include particulate matter (PM 10 and PM 2.5), ozone (O3), nitrogen oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), and lead (Pb).

Federal law requires that all states attain the NAAQS. Geographic areas within each state that do not meet a standard are called non-attainment for that air pollutant. The designation of an area as non-attainment is also important because it triggers the regulatory requirements for banking and use of emission reductions credits. The San Joaquin Valley is one of the non-attainment areas in the State. U.S. EPA classified the San Joaquin Valley as extreme non-attainment for ozone and serious non-attainment

for PM2.5. Non-attainment areas must develop plans, called State Implementation Plans (SIPs), to attain the NAAQS. SIPs are comprehensive plans that describe how an area will attain, or maintain, NAAQS.

The SIPs' main purposes are to demonstrate that the State has the basic air quality management program components in place to implement a new or revised NAAQS, to identify the emissions control requirements the State will rely upon to attain and/or maintain the primary and secondary NAAQS, to prevent air quality deterioration for areas that are in attainment with the NAAQS, and to reduce criteria pollutants emitted in nonattainment areas.

The FCAA Amendments of 1970 also authorize California to set its own separate and stricter-than-federal emissions standards to address California's extraordinary circumstances of population, climate, and topography that pose serious air quality challenges. CARB focuses on California's unique air quality challenges by setting the State's own stricter emissions standards for a range of statewide pollution sources including vehicles, fuels, and consumer products.

The FCAA sets deadlines for attainment based on the severity of an area's air pollution problem. Failure of a state to reach attainment of the NAAQS by the target date can trigger a change in attainment status, new planning, and possibly penalties, including withholding of federal highway funds.

State law makes CARB the lead agency for all purposes related to the California SIP. CARB and local air pollution control districts work together in developing clean air plans to demonstrate how and when California will attain, or maintain, air quality standards established under both the FCAA and the California Clean Air Act. Local air pollution control districts, such as the SJVAPCD, develop plans that describe how the districts will reduce emissions to meet air quality standards by the deadlines, and implement control measures in their areas. These controls primarily affect stationary sources, such as manufacturing and goods processing facilities.

As part of the control strategy at the local level, districts regulate stationary emission sources by adopting control strategies such as district permitting rules and prohibitory rules (prohibitory rules are rules that apply to specific types of equipment or industries). The rules achieve emissions reductions by setting limits and by requiring controls, certifications, or work practices that minimize emissions. Many of these rules have been made stricter over time. The permitting process is the vehicle by which the District implements and enforces rule requirements. An operating permit contains clear, enforceable conditions that spell out each of the rule requirements, and includes associated recordkeeping, monitoring, or testing requirements to ensure that it can be demonstrated that the conditions are being adhered to.

D. Permitting – Federal Requirements

There are two layers of permitting for major sources: 1) federal process and standards; and 2) district process and standards. In many cases, the district will perform both reviews if the district has a SIP-approved program or is delegated authority to implement the federal permitting program. If a district is not delegated such authority, then U.S. EPA will perform the federal permitting and the district will perform its own permitting. Many of the terms used in both federal and local permitting are the same or similar, however some are different, so it is important to distinguish between them.

Major sources of emissions are subject to Title V (of the FCAA), which establishes a federal operating permit program designed to standardize air quality permits and the permitting process for major sources of emissions across the country. Title V only applies to "major sources." U.S. EPA defines a major source as a facility that emits, or has the potential to emit (PTE) any criteria pollutant or hazardous air pollutant (HAP) at levels equal to or greater than federal Major Source Thresholds (MST). The MST for criteria pollutants varies depending on the pollutant and attainment status (e.g., marginal or moderate, serious, severe, and extreme) of the geographic area in which the facility is located.

The FCAA[5] requires NMSs and FMMs to existing major sources of criteria pollutants to undergo a preconstruction review and permitting process conforming to federal law and regulations. In nonattainment areas, the process is called federal "non-attainment new source review" ("NNSR" or simply "NSR"). Existing "major sources" must comply with certain minimum emission reduction requirements and obtain a Title V operating permit. Federal new source review and District new source review differ in several ways, as discussed further below.

E. Permitting – Local Requirements

Air districts issue permits and monitor new and modified sources of air pollutants in accordance with national, State, and local emission standards. A primary purpose of permitting is to ensure that emissions from such sources will not interfere with the attainment and maintenance of ambient air quality standards adopted by CARB and U.S. EPA. Permit requirements apply to individual processes and devices at major sources and to individual processes and devices at facilities that fall below major source thresholds. Local air district permitting activity falls into two broad categories. The districts must approve any new or modified source that has the potential to emit air pollution before it is constructed. This is called an ATC permit for the source. Most ATC permit approvals are subject to NSR. Once a district inspects a source and

[5] CAA 172(c)(5).

finds that the source complies with its ATC permit, the district will issue a permit to operate (PTO). The operating permits of major facilities must include federal Title V requirements in addition to local district requirements.

## F. New Source Review

New Source Review (NSR) is the title applied to programs regulating the new construction of, and/or modifications to, industrial sources, that have the potential to emit, or will emit, air pollutants. NSR programs establish standards for the construction of new stationary sources and the modification of existing stationary sources such as power plants, refineries, and incinerators. State and federal law mandate requirements for NSR, including offset requirements for new and expanding stationary sources. There are two types of NSR in California: federal and local.

The requirements of NSR must be met before a district will issue an ATC. The minimum requirements of NSR are specified in federal and State laws, but in California NSR is implemented at the local level. The local air districts incorporate the applicable state and federal requirements in their own local NSR rule(s). In addition, the districts may include more stringent requirements in their NSR rule(s). Emissions offsetting and ERCs are required components of NSR in non-attainment areas, such as the San Joaquin Valley.

The California Clean Air Act sets basic requirements for NSR programs in the State. Specific to NSR, each district is to include in its attainment plan, a stationary source control program designed to achieve no net increase in emissions of nonattainment pollutants or their precursors for all new or modified sources that exceed particular emission thresholds.[6]

Each of the 35 districts in California has its own NSR program and issues its own ATCs and PTOs. Each district has adopted its own NSR rules and regulations to comply with state and federal laws. These regulations usually incorporate both the California and federal regulations into one or more rules. Two of the key components of NSR in each of the districts are Best Available Control Technology (BACT) and offsets.

### *1. Best Available Control Technology*

Depending on the type and quantity of emissions of air pollutants that will be emitted from the source and the area designation for that pollutant, the new or modified source may be required to install BACT. In general terms, BACT means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation, emitted from, or which results from any major emitting facility. The SJVAPCD defines BACT as follows:

[6] HSC 40918 – 40920.5.

> [T]he most stringent emission limitation or control technique of the following:
>
> Achieved in practice for such category and class of source;
>
> Contained in any State Implementation Plan approved by the Environmental Protection Agency for such category and class of source. A specific limitation or control technique shall not apply if the owner of the proposed emissions unit demonstrates to the satisfaction of the APCO that such a limitation or control technique is not presently achievable; or
>
> Contained in an applicable federal New Source Performance Standard; or
>
> Any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the APCO to be cost effective and technologically feasible for such class or category of sources or for a specific source.

At a minimum, a specific limitation or control technique must be proposed as BACT if it has been achieved in practice on the same type of equipment, anywhere. Even more stringent emission limitation or control techniques are required, including alternative basic equipment or process or changes of control equipment, if found by the APCO to be technologically feasible for such class or category of sources or for a specific source, and cost effective, even if such a control has never been achieved before.

2. *Offsets*

The California and federal Clean Air Acts each require offsets as an element of air quality attainment plans. State law specifies that each non-attainment area's attainment plan contain a stationary source control program designed to achieve no net increase in emissions of non-attainment pollutants from all new or modified stationary sources. Under California law, a new or modified facility at, or above, a certain threshold must mitigate all emission increases so that the result is no net increase in emissions.

Therefore, new and/or modified sources in California may be required, depending on the type and quantity of pollutants emitted, to mitigate or "offset" the increases in emissions that result from the project, even after installation of BACT. The concept behind offsets is that new and expanding stationary sources of air pollution mitigate, or "offset," new emissions with reductions in air pollution at existing sources. The system is designed to accommodate new emissions so that industrial growth can continue in areas not meeting NAAQS (or CAAQS) while not undermining progress toward achieving clean air mandates.

An offset threshold refers to the level of emissions from a new or modified stationary source above which the source is required to provide offsets to mitigate a new emissions increase. Offset requirements are triggered on a pollutant-by-pollutant basis. For example if the offset threshold for VOC in a given district is 10 tons per year, and a new or modified source is projected to emit 8 tons per year, then the source would not be required to provide offsets to mitigate the 8 ton emission increase. However, if the source is projected to emit 12 tons of VOC, then the source would be required to provide offsets.

Once offsets are triggered, a source must provide ERCs to offset either all or a portion of the permitted emissions. Each district's NSR program differs in whether a source must offset the entire permitted amount of emissions, or only down to the offset threshold. Meaning, in the case described above, where the source is permitted to emit 12 tons of VOC, some districts require the source to offset 12 tons of VOC, where others only require the source to offset 2 tons of VOC down to the 10 ton offset threshold. SJVAPCD requires offsetting down to the offset threshold.

G. The San Joaquin Valley Air Pollution Control District ERC System

This section provides an overview of how the SJVAPCD implements the ERC element of its NSR program.

The history of the SJVAPCD is important for understanding the current ERC program. The SJVAPCD was formed in 1992 by the unification of eight individual county districts. Prior to unification of the District, the eight counties each had independent air quality management programs. Each county had its own set of rules and requirements and thus each county made its own permitting decisions. While each county was subject to essentially the same State and federal requirements pertaining to air quality, there were differences in the way counties made permitting and ERC approval decisions.

The unification of these county programs through the formation of the SJVAPCD created a consistent air quality program Valley-wide. Prior to unification, some counties, such as Kern, had fully developed rules for granting ERCs while other counties had more informal procedures for recognizing ERCs. While permits issued under the new unified District were consistent, it was recognized that the ERCs generated by the individual counties before unification needed to be carried over to the unified District. The SJVAPCD NSR and ERC rules facilitated this by creating procedures and timelines for recognizing and carrying over ERCs created in the individual counties. Thus old ERCs generated by county air districts prior to unification became unified District recognized ERCs. These ERCs still exist today, comprise roughly half of available NOx and VOC ERCs, and may be available to offset new emissions.

Following unification, the District established its own requirements for ERC banking, as further detailed below.

*1. The SJVAPCD New Source Review Program*

The SJVAPCD operates its NSR program to meet federal and State legal requirements. Elements of the program have been approved by CARB and U.S. EPA through the SIP approval process.

Rule 2201 is the District's NSR rule. First adopted in 1991, the District has updated and amended the rule sixteen times, most recently in August 2019. The rule establishes BACT requirements, offset thresholds, and offset requirements. Key elements of the rule include:

- BACT Requirements

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Under Rule 2201, a BACT analysis is required (unless exempted) on (a) any new emissions unit or relocation from one Stationary Source to another of an existing emissions unit with a Potential to Emit exceeding 2.0 pounds in any one day; (b) modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2.0 pounds in any one day; and (c) any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification[7] or a FMM.

- Emissions Offset Threshold

Offset requirements are triggered on a pollutant-by-pollutant basis. Unless exempted, offsets are required if the post-project Stationary Source Potential to Emit (SSPE2) equals or exceeds the following offset threshold levels: VOC and NOx – 20,000 pounds per year; CO – 200,000 pounds per year; SOx – 54,750 pounds per year; PM10 – 29,200 pounds per year. SJVAPCD requires offsets down to the offset threshold.

- Offset Ratios

Rule 2201 establishes distance offsets designed to require additional offsets where the original location of emissions offsets is 15 miles or more away from the source under review. For NMSs and FMMs involving VOC or NOx, and for sources more than 15 miles away from the offset source, the ratio is 1.5. This means that every 1 pound of emissions increase must be offset by 1.5 pounds of emission decrease.

[7] The SB 288 Major Modification calculation procedure is included in Rule 2201 to comply with the requirements of California SB288 which prohibited air district's from relaxing requirements for Federal new source review (as they existed on 12/19/02) as a result of Federal NSR reform.

- Air Quality Improvement Deduction Requirements

New ERCs are discounted by 10% prior to banking, which is called an air quality improvement deduction. For example, if an emission reduction of 10 TPY qualifies for ERCs, then a certificate would be issued to the applicant for 9 TPY, and 1 TPY would be permanently retired by the District. This requirement is designed to help ensure that the implementation of the ERC program results in an overall air quality benefit within the boundaries of the air district.

- Calculation Requirements

Rule 2201 defines calculation methods for applying the NSR rule, including for baseline periods, daily emissions limits, historical actual emissions, and potential to emit. These definitions and requirements apply to both permit engineering review calculations, and to the equivalency demonstration. There are several important calculation differences between the SJVAPCD's rule and the federal program.

The most important distinction for purposes of this review concerns whether ERCs are discounted when they are used. Under federal NSR rules, the value of an ERC is discounted at the time-of-use. Under this approach, each ERC must be re-evaluated based on the rules, regulations, and SIP commitments that apply at the time-of-use. Because many years often elapse between when an ERC is created and when it is used, the adoption of progressively stricter emissions standards can cause the surplus value of an ERC to drop significantly.

Under the SJVAPCD rules, the value of an ERC is calculated when the ERC is issued, and the ERC retains this value for the life of the ERC. This is referred to as "time-of-issuance" value. This means the District grants ERCs based on the "surplus" (in excess of any rules, requirements or plans on the books) value at the time of banking. If at some point in the future a rule is adopted that would have reduced emissions from the banked source, the rule has no effect on the ERC. CARB supported this approach at the time it was originally adopted. In a 1993 letter to U.S. EPA, CARB expressed its view that this approach created incentives for companies to produce and use ERCs, "no company exercising good business judgment would ever purchase ERCs which could become worthless within an unforeseeable future time. This would also tend to discourage modernization, since a valuable ERC would be rendered useless on the open market."

A second calculation difference between SJVAPCD NSR and federal NSR is how an emissions increase is calculated to determine the offset quantity for FMMs. For modified sources that qualify as "clean emissions units,"[8] the emissions increase under SJVAPCD NSR is calculated as the difference between the pre-project PTE and the post-project PTE, i.e. a potential-to-potential basis (for all sources). In contrast, under

[8] Clean emissions units are emissions units equipped with emissions controls 95% efficient or meeting achieved-in-practice Best Available Control Technology requirements in the previous 5 years.

federal NSR (for new major sources and federal major modifications), the emission increase is calculated as the difference between the pre-project actual emissions and the post-project PTE, i.e. an actual-to-potential basis. An actual-to-potential basis (as under federal NSR) will always produce an emissions increase that is equal to or greater than an emission increase determined on a potential-to-potential basis (as under SJVAPCD NSR). Thus, the actual-to-potential calculation is more stringent. Districts differ in terms of the emissions increase calculation for their particular NSR rule. Some, including SJVAPCD, use a potential to potential calculation, while others use an actual to potential calculation, which results in a larger number of offsets required.

Due to the differences between the federal and District NSR programs, in 1999 U.S. EPA and SJVAPCD entered into an agreement requiring SJVAPCD to implement an annual federal offset equivalency tracking system. U.S. EPA required this agreement as a condition of approving SJVAPCD's amended NSR rule for incorporation into the SIP. The purpose of the tracking system is to show, on a program-wide basis, that SJVAPCD's NSR rule requires an equal or greater amount of offsets than would be required under the terms of federal NSR. This is the "equivalency determination" that a major section of this review discusses below.

The District's NSR Rule contains language that describes how the district would modify its program if it were to fail to show equivalency. From the time the tracking system was adopted in August 2001 until present, SJVAPCD has never failed to show equivalency based on its annual demonstration to U.S. EPA. As a result, SJVAPCD has been able to maintain its offsetting system instead of adopting federal offset requirements for NMSs and FMMs to existing major sources. If SJVAPCD were to fail to show equivalency, they would be required, by their existing NSR rule and the agreement with U.S. EPA, to follow federal offsetting standards.

*2. The SJVAPCD ERC Bank*

The District publishes on its website[9] a daily summary of the available (or currently valid) ERCs. Table 1 provides an example of the daily summary from August 1, 2019. The summary reports the ERCs by the region in which the ERCs were banked, however an ERC from one region may be used (retired) to mitigate emission increases in any other region. In 2016, the District estimated[10] that approximately 18% of its NOx ERCs were surplus as of that the time, if evaluated and discounted under a "surplus-at-time-of use" assumption.

[9] http://www.valleyair.org/busind/pto/erc.htm

[10] http://www.valleyair.org/Workshops/postings/2016/05-11-16_OEI/DRAFT-Staff-Report.pdf

**Table 1. Available Annual ERCs in the San Joaquin Valley by Region (August 2019)**

| Pollutant (lbs/yr) | Northern Region | Central Region | Southern Region | Total District |
|---|---|---|---|---|
| VOC | 748,373 | 589,690 | 8,847,980 | 10,186,043 |
| NOx | 2,005,863 | 740,185 | 8,242,410 | 10,988,458 |
| CO | 1,691,911 | 1,011,453 | 51,328,838 | 54,032,202 |
| PM10 | 739,839 | 980,277 | 962,531 | 2,681,897 |
| SOx | 1,654,602 | 664,580 | 3,914,109 | 6,233,291 |
| Acetone | 71,826 | 2,695 | None | 74,521 |
| Ethane | None | 14,134 | 1,879,617 | 1,893,751 |
| Hydrogen Sulfide | None | 107 | 45,005 | 45,112 |
| PM2.5 | None | None | 3,218 | 3,218 |
| Sulfate Particulate | None | None | 191,193 | 191,193 |
| - | - | - | - | - |
| CO2E (MMT/yr) | 2,444 | 259,575 | 636,315 | 636,315 |

Figures 1 and 2 below show the percentage of available VOC and NOx ERCs in the bank according to the age (grouped by decade) of the emission reductions that created them. The charts show that the majority of VOC (89%) and NOx (85%) ERCs remaining in the bank unused are based on emission reductions that occurred more than 20 years ago.[11]

[11] Note that the ERC totals (lb/yr) for VOC and NOx in the charts below will not equal the VOC and NOx totals in Table 1 above because the charts only represent banking actions through 2018, whereas Table 1 is current as of August 1, 2019.

**Figure 1. Age of VOC ERCs Available in the SJVAPCD Bank**

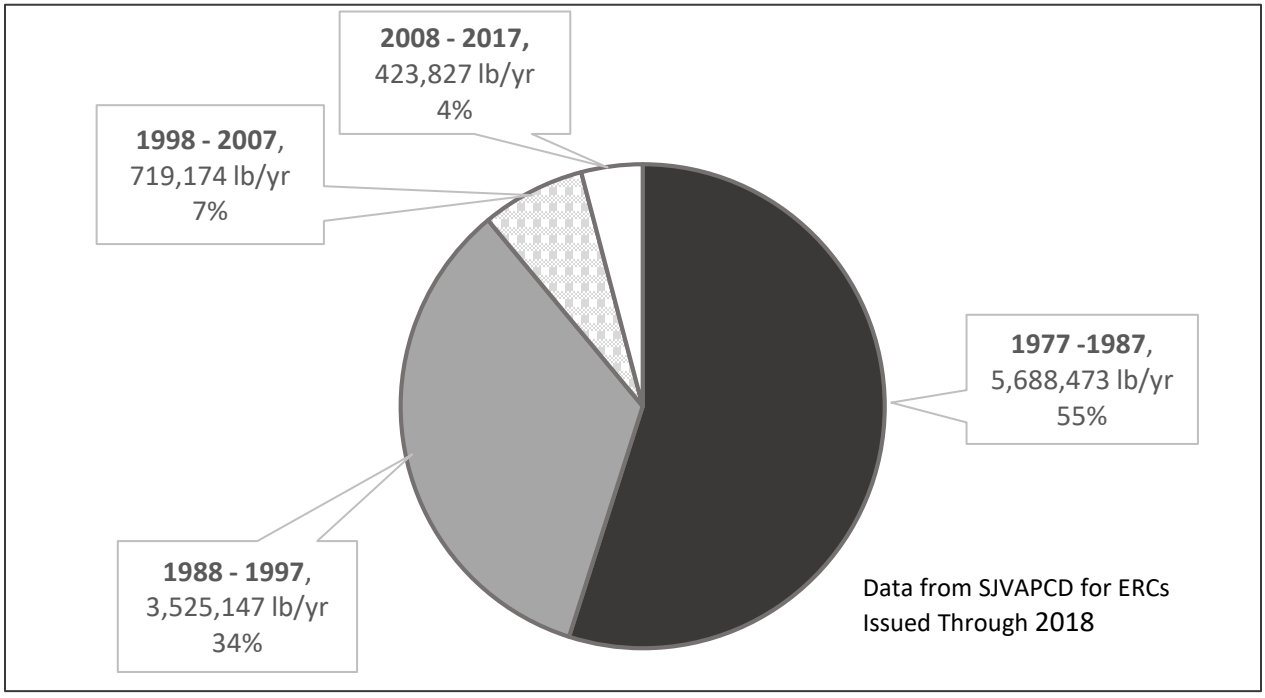
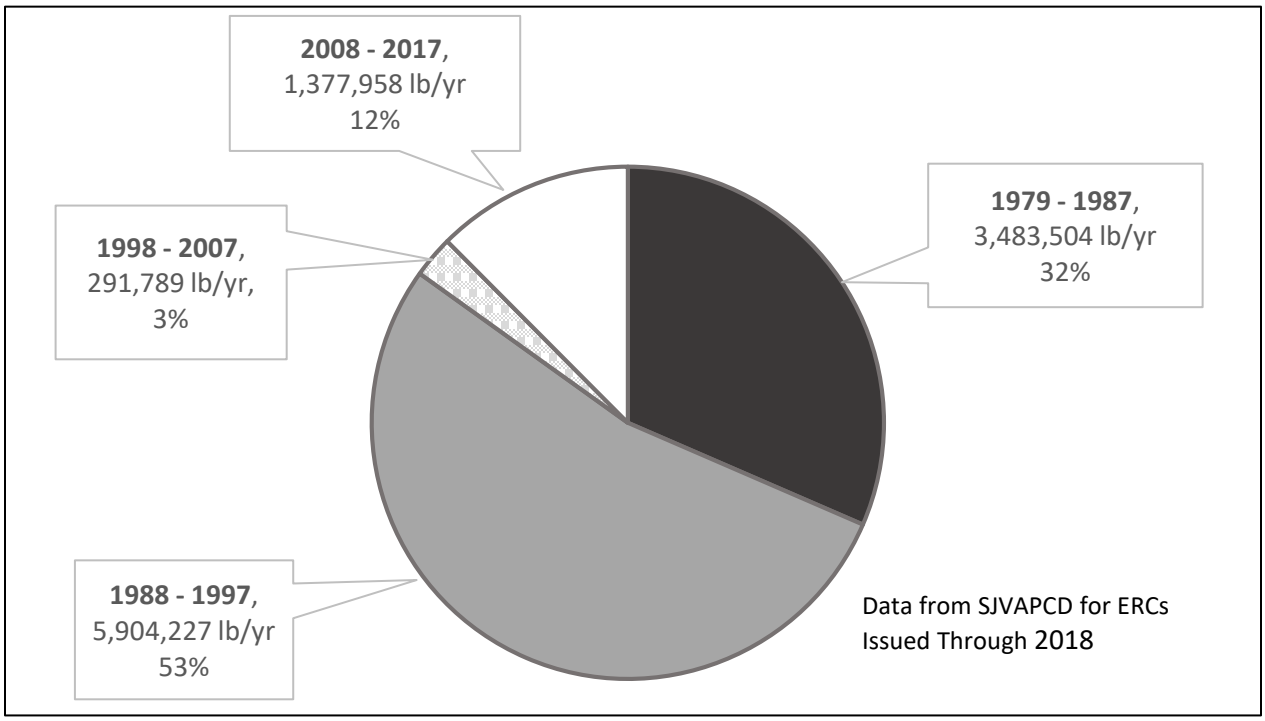



**Figure 2. Age of NOx ERCs Available in the SJVAPCD Bank**



*3. Demonstrating Equivalency*

When originally established, the District's NSR program required more offsets than the federal NSR program, primarily because District emissions offset thresholds and offset ratios were more stringent compared to federal NSR. However, in 2010, the San Joaquin Valley's federal non-attainment ozone classification was bumped up from severe to extreme. As a result, the federal major source and major modification thresholds for ozone precursors dropped to levels that eliminated the primary advantage SJVAPCD's NSR program had in offset stringency over the federal NSR program for NOx, VOC, and CO.

Since the reclassification to extreme non-attainment for ozone in 2010, SJVAPCD's tracking system frequently relies on the carry-over of past mitigations and reductions. To demonstrate equivalency for NOx and VOC the District has relied heavily on past, unbanked reductions from orphan shutdowns and electrification projects (i.e., reductions not used for ATC projects). For example, between 2010 and 2018, half of all VOC reductions, and 75% of all NOx reductions included in the District's equivalency demonstrations were provided by orphan shutdowns and electrification projects, with the remaining value provided by ERCs.

Figures 3 and 4 below display the emissions reductions claimed by source type by the District to demonstrate federal offset equivalency between 2010 and 2018. For NOx, electrification projects comprised the majority of offsets used to demonstrate equivalency, and for VOC both ERCs and orphan shutdowns were used to demonstrate equivalency.

Part 3 of this report provides further discussion and analysis of the District's equivalency program.

**Figure 3. Surplus at Time-of-use Equivalency: NOx Mitigation by Source**

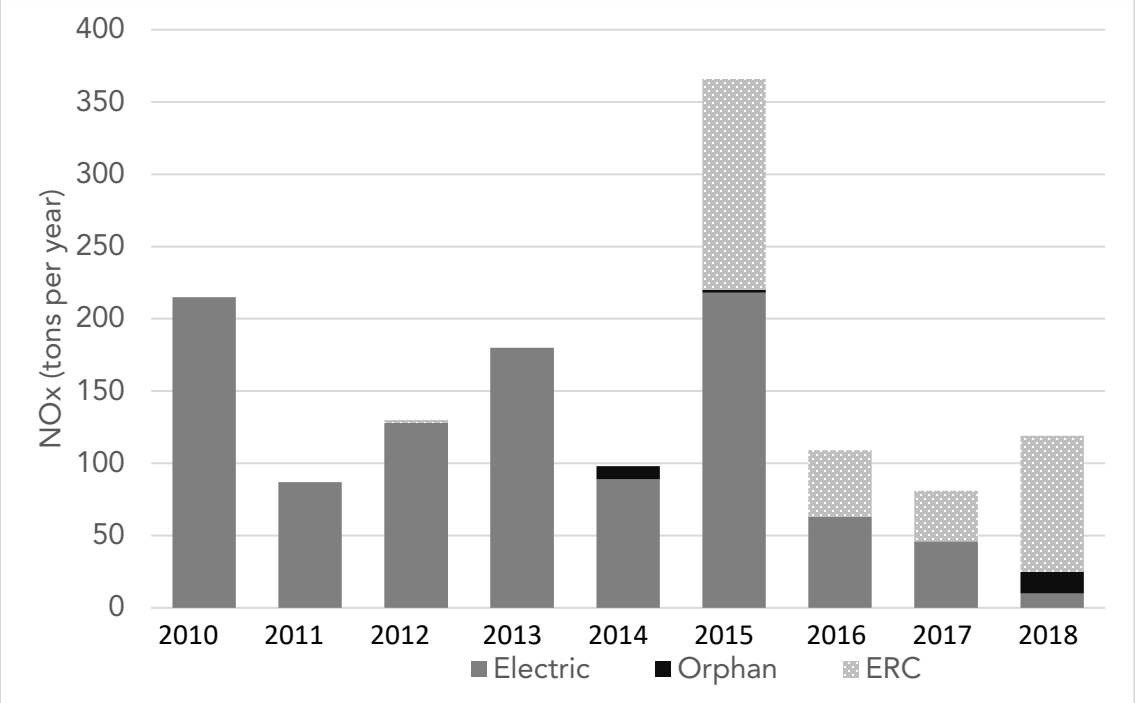
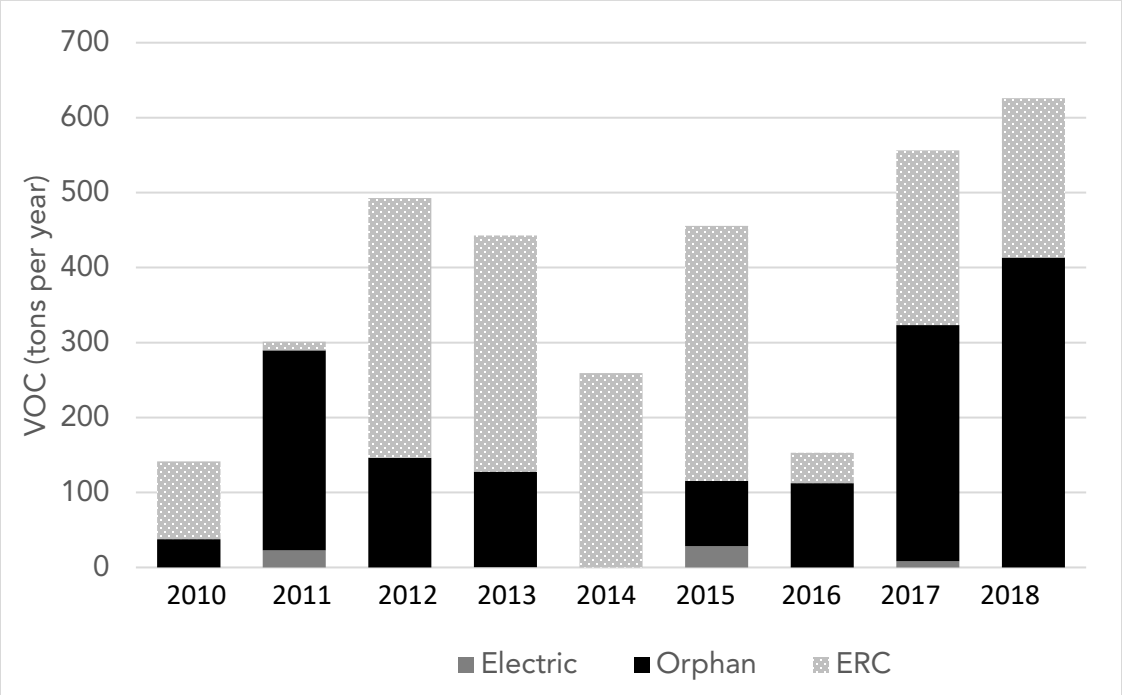



**Figure 4. Surplus at Time-of-use Equivalency: VOC Mitigation by Source**



H. Summary of Findings for Part 1

The current SJVAPCD ERC bank contains nearly 11 million pounds per year of NOx ERCs when valued at time-of-issuance, more than 80% of which were generated more than 20 years ago. However, over the years, the District's regulatory program has become more stringent, and the District estimated in 2016 that these NOx ERCs, when valued at time-of-use, were worth about 18% of the time-of-issuance value.[12] This reduction in time-of-issuance value is directly related to the stringency of the District's regulatory program. In effect, as the District increases the stringency in its regulatory program, it also reduces the time-of-use value in its ERC bank, which makes achieving equivalency more difficult. By way of example, when a business uses a 100 TPY ERC to offset a 100 TPY emissions increase, the business gets full use of the 100 TYP face value of the ERC. However, when the District accounts for the use of the same 100 TPY ERC in the context of the equivalency determination, its surplus-at-time-of-use value may be much less. In the case of NOx, on average, the 100 TPY NOx ERC would only be able to "offset" 18 TPY in the equivalency determination calculation.

At the same time, the District's NSR program, once significantly more stringent than federal requirements no longer is for NOx and VOC because of the District's reclassification to extreme non-attainment status for ozone in 2010. Prior to reclassification, the District's offsets thresholds for major sources were below the federal offset threshold and therefore the District required a greater use of offsets to mitigate emissions increases than what was federally required. However, upon reclassification, the District's offset threshold was no longer lower than the federally required threshold, which created a situation in which more offsets are generally required for major sources under federal requirements than under district rules. This change has been exacerbated by the fact that there generally are not sufficient reductions from the application of the NSR ERC program to offset the difference between time-of-issuance and time-of-use value of ERCs. The District uses orphan shutdowns and electrification projects to provide additional emissions reductions that are needed to demonstrate equivalency because the remaining portions of the program do not appear to provide sufficient additional offsets. These emission reductions are not generated as part of the ERC system, but are used to demonstrate offset equivalency between the District program and federal requirements. On the other hand, the District has not to date incorporated other eligible and more stringent requirements of their NSR rule into the offset equivalency demonstration, such as the application of BACT requirements to minor sources which is beyond federal requirements.

[12] SJVAPCD Draft Staff Report for Annual Offset Equivalency Determination, April 19, 2016, page 6

## III. Part 2: Evaluating ERC Projects

This section discusses Part 2 of the review, in which staff evaluated 52 individual ERC projects, which represents 201 individual ERC banking certificates.[13] Staff's evaluation focused on whether the projects conformed to District rules, as well as federal and State requirements. Staff focused particularly on timeliness of applications; baseline determinations and calculations; and the evaluation criteria (real, quantifiable, surplus, permanent, and enforceable). In addition, staff reviewed emission calculations and engineering evaluations for accuracy and completeness of information. Because the Earthworks Report identified potential issues with specific ERCs, CARB staff included in this review all of the ERCs discussed in the Earthworks Report. To ensure the sample of ERCs in this review provides an adequate representation of the entire ERC program, CARB selected additional ERCs for evaluation using a random selection and representing the following criteria:

- A variety of locations, including varied regions of SJVAPCD;
- A variety of industries;
- A range of magnitude of emissions banked; and
- A range of dates in which the project took place.

To select ERCs for review, staff first identified the full population of projects and ERCs. Staff identified 1,358 projects and 2,101 ERC certificates listed in the District's ERC bank. From this population, staff selected 52 ERC projects representing 201 individual single pollutant ERC certificates, including those addressed in the Earthworks Report and additional projects chosen by CARB staff to provide a representative overview of the program.

Table 2 below lists the ERC project codes associated with the 52 ERC projects selected for review. District staff assign ERC project codes when an ERC application is submitted. The first letter of the project code indicates which region the reduction originated in (N for northern, C for central, and S for southern). The remaining numbers uniquely identify each project. Each ERC project code represents between one and five actual ERC certificates because a unique ERC certificate is issued for each pollutant banked, even if they result from the same project. For each of these projects, staff requested the contents of the project file from the District, and reviewed information available in the District's permitting database, PAS. Key publicly available information which staff used to review these projects can be found on CARB's website at the following address: https://ww2.arb.ca.gov/our-work/programs/san-joaquin-valley-emission-reduction-credit-program-review

[13] An ERC banking action, or "project", can involve a banking of multiple pollutants, and an individual ERC certificate is issued for each pollutant banked in an action or project.

## Table 2. List of ERC Projects that CARB Reviewed

| ERC Project Number | Date of Issuance | Number Certificates Issued | VOC (tpy) | NOx (tpy) | CO (tpy) | PM10 (tpy) | SOx (tpy) | CO2e (tpy) (metric) |
|---|---|---|---|---|---|---|---|---|
| S-851028 | 7/23/1987 | 2 | 2,202.3 | - | 11,459.8 | - | - | - |
| S-870731 | 4/14/1988 | 5 | 261.3 | 509.4 | 4730.2 | 6.6 | 295.8 | - |
| S-920255 | 9/27/1994 | 23 | 1,168.0[14] | - | - | - | - | - |
| S-910706 | 3/30/1992 | 5 | - | 58.7 | 8.1 | 20.8[15] | 386.4 | - |
| S-920024 | 12/17/1992 | 5 | | 3.3 | 10.4 | 3.6[16] | 126.5 | - |
| S-930509 | 7/14/1994 | 4 | - | 110.9[17] | - | - | - | - |
| S-950784 | 12/6/1996 | 1 | 103.6 | - | - | - | - | - |
| S-981134 | 4/12/1999 | 1 | - | 9.9 | - | - | - | - |
| S-1010702 | 12/17/2001 | 1 | - | 13.1 | - | - | - | - |
| S-1020219 | 4/28/2003 | 1 | - | - | - | 8.74 | - | - |
| S-1052797 | 12/6/2006 | 4 | 38.2 | 7.1 | 20.2 | 2.6 | - | - |
| S-1075362 | 5/15/2008 | 4 | 11.5 | 11.8 | 52.7 | 0.8 | - | - |
| S-1080067 | 5/14/2008 | 4 | 0.1 | 0.7 | 1.3 | 0.1 | - | - |
| S-1113860 | 1/19/2012 | 1 | 4.5 | - | - | - | - | - |
| S-1120775 | 2/13/2014 | 2 | - | - | - | - | - | 70,788[18] |
| S-1122749 | 3/24/2015 | 1 | - | - | - | - | - | 12,003 |
| S-1122845 | 7/14/2014 | 6 | 0.5 | 4.7 | 3.2 | 1.7 | 0.03 | 30,279 |
| S-1123816 | 4/19/2017 | 1 | - | - | - | - | - | 257,426 |
| C-1130364 | 10/7/2015 | 6 | 0.04 | 0.1 | 3.5 | 0.1 | 0.002 | 161 |
| S-1141060 | 8/26/2015 | 4 | - | 42.0 | 99.6 | 13.9 | 9.2 | - |
| S-1144501 | 7/12/2017 | 1 | 1.5 | - | - | - | - | - |
| S-1154368 | 4/3/2017 | 3 | - | 0.1 | 1.9 | 0.6 | - | - |

[14] 1,168.0 tpy is the total of twelve separate VOC ERC certificates issued for this project. In addition, eleven ethane ERC certificates were issued.
[15] A separate ERC for 8.4 tpy sulfates was also issued.
[16] A separate ERC for 1.8 tpy sulfates was also issued.
[17] 110.9 tpy is the total of four separate NOx ERC certificates issued for this project.
[18] 70,788 is the total for two separate CO2e ERC certificates issued for this project.

| ERC Project Number | Date of Issuance | Number Certificates Issued | VOC (tpy) | NOx (tpy) | CO (tpy) | PM10 (tpy) | SOx (tpy) | CO2e (tpy) (metric) |
|---|---|---|---|---|---|---|---|---|
| S-1171326 | 3/12/2018 | 4 | - | 19.8 | 6.1 | 7.8 | 0.2 | - |
| S-1180895 | 8/21/2018 | 5 | 0.3 | 0.4 | 11.1 | 0.3 | 0.8 | - |
| C-920318 | 9/13/1993 | 5 | 61.0 | 11.0 | 2.7 | 112.7 | 0.05 | - |
| C-950579 | 6/12/1996 | 3 | 3.5 | 22.6 | 18.2 | - | - | - |
| C-970158 | 1/7/1999 | 5 | 20.7 | 6.0 | 31.4 | 0.7 | 0.04 | - |
| C-980294 | 8/18/2003 | 5 | 0.7 | 5.5 | 74.2 | 1.1 | 4.4 | - |
| C-1010009 | 3/15/2001 | 5 | 163.9 | 1.5 | 1.4 | 39.5 | 0.02 | - |
| C-1011235 | 7/16/2002 | 5 | 1.5 | 14.6 | 2.2 | 0.7 | 0.2 | - |
| C-1032163 | 3/29/2004 | 5 | 0.01 | 0.2 | 0.2 | 9.9 | 0.006 | - |
| C-1040561 | 10/6/2004 | 5 | 0.03 | 0.7 | 0.1 | 7.5 | 0.04 | - |
| C-1063777 | 4/30/2007 | 5 | 0.02 | 0.4 | 0.1 | 9.5 | 0.003 | - |
| C-1120248 | 7/9/2012 | 5 | 0.4 | 32.9 | 32.7 | 6.8 | 22.8 | - |
| C-1162473 | 7/12/2017 | 5 | 0.009 | 0.2 | 0.03 | 8.0 | 0.03 | - |
| C-1162737 | 1/30/2018 | 1 | 5.3 | - | - | - | - | - |
| C-1171943 | 7/26/2018 | 6 | 0.003 | 0.1 | 0.01 | 3.9 | 0.01 | 79 |
| C-1172943 | 7/8/2019 | 5 | 0.1 | 0.9 | 0.7 | 2.1 | 0.01 | - |
| C-1173456 | 10/11/2018 | 5 | 0.003 | 0.05 | 0.01 | 5.5 | - | 56 |
| N-930450 | 5/19/1995 | 4 | 0.1 | 45.5 | - | 1.6 | 17.5 | - |
| N-950107 | 5/21/1996 | 1 | - | - | 37.9 | - | - | - |
| N-950151 | 3/4/1996 | 1 | - | 163.5 | - | - | - | - |
| N-950288 | 12/8/1998 | 5 | 68.3 | 79.0 | 69.3 | 12.7 | 6.4 | - |
| N-960487 | 6/3/1997 | 5 | 1.0 | 36.0 | 10.8 | 8.1 | 0.7 | - |
| N-970384 | 11/5/1998 | 5 | 1.7 | 243.6 | 42.1 | 49.8 | 341.3 | - |
| N-980337 | 5/25/2000 | 5 | 107.5 | 14.1 | 9.4 | 3.0 | 0.2 | - |
| N-1000509 | 10/29/2008 | 1 | - | - | - | 6.4 | - | - |
| N-1001257 | 8/14/2002 | 5 | 0.5 | 55.9 | 40.7 | 9.5 | 28.1 | - |
| N-1061341 | 2/20/2008 | 5 | 2.7 | 20.8 | 54.3 | 0.03 | 4.3 | - |

| ERC Project Number | Date of Issuance | Number Certificates Issued | VOC (tpy) | NOx (tpy) | CO (tpy) | PM10 (tpy) | SOx (tpy) | CO2e (tpy) (metric) |
|---|---|---|---|---|---|---|---|---|
| N-1062909 | 5/26/2011 | 2 | 14.7 | - | - | 0.6 | - | - |
| N-1101305 | 12/19/2012 | 1 | 32.8 | - | - | - | - | - |
| N-1131840 | 2/21/2017 | 1 | - | - | - | - | 28.3 | - |

A. Findings

In reviewing the 52 ERC projects, staff identified four areas in which the District's program requires improvement:

1. Transparency
2. Timeliness of Application and Selection of Baseline Periods
3. Real and Permanent Reductions
4. Surplus Reductions

This section provides an overview of each of these areas of concern, with reference to the affected ERC projects.

*1. Transparency*

In about half of (27 of 52) ERC projects reviewed, the District's project files lacked sufficient supporting documentation that would be necessary to replicate or verify the information used in the District evaluation or provided in the facility application. The ERC projects were missing information such as emissions inventory submittals, choice of baseline period, Continuous Emission Monitoring (CEMS) data, source test data, and other information. The following ERCs lacked sufficient documentation: C-920318, C-920255, C-1010009, C-1032163, C-1130364, C-1162737, C-1172943, C-1173456, N-930450, N-950107, N-950288, N-960487, N-980337, N-1062909, N-1131840, S-851028, S-870731, S-910276, S-920024, S-1020209, S-1075362, S-1113860, S-1122749, S-1122845, S-1123816, S-1141060, and S-1144501.

The ERC process should ensure that the ERC file is complete and transparent, such that a reviewer, or member of the public, can readily replicate the decision made. Three examples of transparency issues found during the review are illustrative of ERCs with similar issues.

- S-1144501: The proposed reduction resulted from shutdown of two floating roof crude oil production tanks. The referenced ERC was issued in 2017. The District's files provide no discussion of the reason the District chose an alternative baseline period for the facility, rather than the two years immediately preceding the date of

application. There is no detail of the quarterly average production data calculations, and using the raw data, the District values cannot be duplicated. In addition, the District relied on the permit surrender date for justification of application timeliness, yet the letter from the applicant surrendering permits is not included in the District's files.

- N-960487: The proposed reduction resulted from the shutdown of a sugar manufacturing facility. The throughput and fuel usage were supplied by a consultant on behalf of the applicant, without any supporting documentation or records. The file did not include any emission inventory submittals, nor any evidence that the District verified the information in the application.
- N-1062909: The proposed reduction resulted from the shutdown of a steel storage system manufacturing facility. The District sent several letters requesting more information from the applicant regarding amount of paint used and VOC contents of paints, but the file contains no resolution of the requests. The project files do not contain final issuance letters. The District took over four years to determine the application was complete, but the file contains no explanation for this delay.

*2. Timeliness of Application and Selection of Baseline Period*

District's banking rule (Rule 2301) governs the timeline for applications for ERC banking. CARB staff interprets the rule as being clear that the application must be submitted within 180 days of when emission reductions occurred. To interpret Rule 2301, District follows Policy APR 1805 (4/9/1992)[19]. CARB staff believes that Rule 2301 and APR 1805 are inconsistent. The District maintains that the rule and policy are consistent but has committed to making adjustments to reduce the likelihood of future actual or perceived inconsistencies.

In the San Joaquin Valley, most ERCs are generated from the shutdown of a facility or process. In 15 of the 52 projects reviewed, the District granted ERCs for reductions generated by a facility shutdown that occurred more than 180 days before submission of the ERC application following Policy APR 1805. The 15 affected ERC projects are: S-1075362, C1010009, C-950579, C-970158, C-1032163, C-1063777, C-1130364, C-1162473, C-1172943, C-1173456, S-430424, N-1001257, S-870731, S-1080067, S-1122845. For many of these ERCs, the District also selected baseline periods reflecting operation of the facility even though the facility had not operated within 180 days of, and sometimes in years prior to, the ERC application.

District Rule 2301, Sections 4.2 and 4.2.3 states:

[19] https://www.valleyair.org/policies_per/Policies/APR%201805.pdf

*4.2 Affected Pollutant Emissions Reductions Occurring After September 19, 1991*

*For emission reductions occurring after September 19, 1991, the following criteria must be met in order to deem such reductions eligible for banking: …*

*4.2.3 An application for ERC has been filed no later than 180 days after the emission reductions occurred.*

The District does not define the date "emission reductions occurred," however, it is the District's position that the date the "emission reductions occurred" for facilities which are shutting down and applying for ERCs is the date of the "shutdown." The District defines "shutdown" in their regulations, although the term is not used in the timeliness language. Specifically, District regulations define shutdown as *the earlier* of the permanent cessation of emissions from an emitting unit or the surrender of that unit's operating permit. Rule 2301, Section 3.14, defines "shutdown" as:

*Shutdown: shall mean either the earlier of the permanent cessation of emissions from an emitting unit or the surrender of that unit's operating permit. If, prior to the surrender of the operating permit, the APCO determines that:*

*the unit has been removed or fallen into inoperable and unmaintained condition such that startup would require an investment exceeding 50% of the current replacement cost; and*

*the owner cannot demonstrate to the satisfaction of the APCO that the owner intended to operate again, then the APCO may cancel the permit and deem the source shutdown as of the date of last emissions. Evidence of an intent to operate again may include valid production contracts, orders, other agreements, or any economically based reasons which would require the operation of the emitting unit after initial cessation of emissions.*

District Policy APR 1805, Definition of a Shutdown defines shutdown as follows:

*For permitted sources, the date of the shutdown shall be the date of the surrender of the operating permit, unless the Control Officer determines that: a) the unit has been removed or has fallen into an inoperable and unmaintained condition such that start-up would require an investment exceeding 50% of the current replacement cost; and, b) the owner cannot demonstrate to the satisfaction of the Control Officer that the owner intended to operate again. Evidence of "intent to operate again" may include valid production contracts, orders, other agreements, or any*

*economically based reasons which would require the operation of the emissions unit.*

*Should the Control Officer make determinations a) and b), the date of the shutdown shall be the date of the last emissions from the emissions unit.*

District Policy APR 1805 further states "*We further recommend that the definition be changed, by rule amendment, at the first opportunity. The wording of the attached interpretation may be appropriate for such an amendment.*"

By following Policy APR 1805 in reviewing the timeliness of ERC projects, the District is accepting ERC applications submitted more than 180 days after the date emission reductions occurred, which CARB staff interprets as in conflict with the District's Rule. The acceptance of applications more than 180 days after cessation of emissions impacts the selection of the baseline period. District Rule 2201, Section 3.9, defines the baseline period as: "the two consecutive years of operation immediately prior to the submission date of the Complete Application" or "[a]t least two consecutive years within the five years immediately prior to the submission of the complete application if it is determined by the APCO as more representative of normal source operation."[20] In 14 of the 15 ERCs identified as being issued more than 180 days since cessation of emissions, the District defined a baseline period consisting of two years that were not immediately prior to the submission of the application.

While the District's reliance on District Policy APR 1805 with respect to application timeliness appears to have been consistent since 1992, CARB staff concludes that the policy and the rule are not aligned and should be modified accordingly. When coupled with the District's selection of baseline periods, the application of the policy has led to the issuance of ERCs for facility shutdowns that occurred more than 180 days prior to application, with credit for normal levels of activity prior to shutdown. The district has committed to a process to align the policy and the rule.

*3. Source Shifting Considerations*

In 10 projects (6 criteria pollutant and 4 GHG ) of 52 ERC projects reviewed the reductions may not have been real and permanent as the pollution activity and emissions may have shifted to a different facility.[21]

In ERC projects for criteria pollutants, the District may consider the potential for the emissions reductions proposed for banking being shifted to another nearby source or

[20] Different baseline periods apply to sources that have been in operation for less than two years in total. These periods do not apply to the projects staff reviewed.

[21] CARB includes this review of GHG issues in part because non-profit groups raised concerns on this program as well. CARB recognizes that the GHG program is not directly linked to NOx offsets for ozone attainment, but GHG reductions, too, should be properly handled, given the significant public health implications of GHG emissions.

source within the air basin. This "source shifting" consideration is expressed implicitly in Rule 2301, Section 4.4.1 which bans certain source categories such as gasoline stations from banking emission reductions. The rationale for this exclusion is that the shutdown of a gasoline station will not result in any permanent or real emission reductions because the demand for gasoline will remain the same and the activity of refueling will be shifted to another nearby gasoline station. Thus, the air basin will see the same emissions as before the shutdown.

Where an emissions reduction creates a potential for source shifting, it is best practice for the ERC application to address this issue specifically by conducting an analysis to demonstrate source shifting is not occurring or that it is being compensated for in the amount of ERC being issued.

Staff observed that the issue of source-shifting was not explained adequately in some criteria pollutant banking actions where it could be an issue, in particular, in the banking of emissions from cotton gins in projects C-1032163, C-1040561, C-1063777, C-1162473, C-1171943, and C-1173456. While the District explained that cotton production was declining as an industry within the San Joaquin Valley, which CARB staff concurs, the District did not explain how this ensured that the production from one cotton gin shutting down was not being shifted to another nearby gin. In some cases, there was another nearby gin within a few miles. The District could improve its assessments by addressing source shifting more explicitly and comprehensively in its review of ERC applications.

The District considered the issue of source shifting when amending Rule 2301 to allow banking of GHG reductions. In presenting the Rule change, District staff noted certain reductions would be ineligible for banking –including shutdowns where "global demand for product/service does not decrease, product/service will be produced elsewhere (and result in GHG emissions)."[22] While this language was not directly incorporated into the Rule, the stated interpretation is consistent with the requirement that reductions be real and permanent.

Because the effects of GHGs are global, some account of global demand and therefore source shifting, on a global basis, is appropriate to ensure reductions are real and permanent. However, in the analysis of GHG banking projects (S-1122749, S-1123816, S-1122845, and C-1130364) for the shutdown of oil and gas production equipment (pre-Cap and Trade), the District did not apply this global level of scrutiny. The District assumed the GHG reductions would be real and permanent based on documentation of declining oil and gas production in California. However, a global boundary and demonstration of source shifting would have been more appropriate to

[22] http://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2012/January/Item11-Rule2301011912presentation.pdf

show the reductions are real and permanent given that oil and gas are global commodities not on a downward trend, many producers are global, and the effects of GHGs are global.

Ultimately, the impact of these GHG ERCs is not clear, as there is no currently authorized use in an NSR context consistent with District rules or in the context of GHG Cap and Trade programs. To CARB's knowledge, none of these GHG ERCs have been used.

*4. Surplus Reductions*

In four of the 52 ERC applications reviewed (S-1075362; S-981134; S-851028; and C-1010009), it is unclear whether a portion of the reductions issued an ERC were not surplus. These issues are particularly complicated – influenced by federal, state, and local requirements.

For purposes of ERC banking, State law requires:[23]

> *(a) Every district board shall establish by regulation a system by which all reductions in the emission of air contaminants that are to be used to offset certain future increases in the emission of air contaminants shall be banked prior to use to offset future increases in emissions. The system shall provide that only those reductions in the emission of air contaminants that are not otherwise required by any federal, state, or district law, rule, order, permit, or regulation shall be registered, certified, or otherwise approved by the district air pollution control officer before they may be banked and used to offset future increases in the emission of air contaminants.*

Federal law requires:[24]

> *(c) Offsets (2) Emission reductions otherwise required by this chapter shall not be creditable as emissions reductions for purposes of any such offset requirement*

District rules require:[25]

> *3.2.2 To be considered surplus, [actual emissions reductions] shall be in excess, at the time the application for an Emission Reduction Credit or an Authority to Construct authorizing such reductions is deemed complete, of any emissions reduction which:*

[23] California Health and Safety Code 40709.
[24] Clean Air Act Section 173(c)(2).
[25] SJVAPCD Rule 2201, 3.2.2.

*3.2.2.1 Is required or encumbered by any laws, rules, regulations, agreements, orders, or*

*3.2.2.2 Is attributed to a control measure noticed for workshop, or proposed or contained in a State Implementation Plan, or*

*3.2.2.3 Is proposed in the APCO's adopted air quality plan pursuant to the California Clean Air Act.*

CARB recognizes that these rules and requirements are complex. However, all these requirements focus on a careful evaluation of whether an ERC is truly surplus relative to controlling law. This issue is particularly important to reevaluate, as a policy matter, because the time-of-issuance program in San Joaquin can mean ERCs issued under one legal regime are no longer truly surplus at use in light of changes in law since issuance. This becomes more important because the District, not the applicant, must identify sufficient time-of-use reductions in the context of the Equivalency Demonstration.

The four applications where it is unclear as to whether the full value of the ERCs were in fact surplus in light of changes in law.

- ERC S-981134 involved a refinery applying for ERCs for emissions reductions achieved from the required installation of BACT in 1998. The facility received an Authority to Construct (ATC) Permit # S-33-56-11 to increase the firing rate capacities of two heaters on a hydrocracking unit. This modification triggered BACT for NOx, and the District determined BACT for NOx to be a technology capable of meeting a NOx emission rate of 0.036 lb/MMBtu. The District granted an ERC for reductions achieved between the rule requirement and BACT.

  This approach was consistent with District Rule 2201 as adopted in 1995, which required emissions reductions selected for banking to be in excess of any emissions reduction required by any law, rules, regulations, agreements, or orders – except controls required by the District's NSR Rule. However, District Rule 2201 as adopted in 1995 was inconsistent with California Health and Safety Code section 40709 and federal Clean Air Act section 173(c)(2), discussed above, which require banked reductions to be surplus of all requirements including NSR requirements for BACT. The District subsequently amended Rule 2201 in 1998 to remove the language allowing banking of emissions reductions required by installation of BACT in NSR.

- ERC S-851028 involved benzene emissions reductions from the installation of a boiler on a fluid coker at a refinery in 1987. CARB and USEPA appeared to differ with the Kern County Air Pollution Control District on whether or not the reductions were surplus and therefore eligible for banking. EPA and CARB both commented that the reductions had occurred 10 years earlier and were already

accounted for in the non-attainment plan, and RACT at the time of banking was incineration. This ERC was discussed extensively in the Earthworks evaluation, and the record regarding this ERC is not clear. Ultimately, the Kern County Air Pollution Control District issued the ERCs, despite comments from CARB and U.S. EPA at the time which raised issues about the eligibility of the emissions reductions that the Kern County Air Pollution Control District did not fully address.

- ERC C-1010009 involved an ERC application in July 2000 for the shutdown of equipment at an oil mill used for seed processing. The facility continued to operate exclusively as a cottonseed receiving and storage facility. Prior to the ERC application, in May of 2000, the US EPA had published a notice to update a NESHAP (40 CFR Part 63 Subpart GGGG) applicable to the source. The District did not discount the ERC for the proposed NESHAP because it believed its rules did not require it to do so, and finalized the ERC in March 2001. However, US EPA finalized the NESHAP in April 2001, which reduced the time-of-use value of the ERC by 280,000 pounds of VOC per year, a reduction of roughly 80%, just weeks after the ERC was issued. This example highlights why time-of-issuance ERCs can be problematic as a policy matter, given this notable difference in reduction value.
- ERC S-1075362 involved the shutdown of six CNG engines. In this application, the applicant requested ERCs for reductions above the most stringent regulatory internal combustion emissions limit incorporated into a SIP in California – the 36 ppm NOx limit set forth in South Coast AQMD Rule 1110.2 (revised on June 3, 2005). The applicant used South Coast AQMD Rule 1110.2 for the Reasonably Available Control Technology (RACT) adjustment because the 36 ppm NOx limit was more stringent than the emissions limit under SJVAPCD Rule 4702. The application noted that SJVAPCD Rule 4702 had been identified as a further study measure, but no new draft potential emission limits had been published. As a result, the applicant calculated reductions using the 36 ppm NOx emissions limit.

  The District granted the ERC assuming an emissions limit of 65 ppm NOx, rather than the 36 ppm NOx emissions limit proposed by the applicant. This increased the value of the ERC. The District's evaluation did not include an explanation for the decision to use the 65 ppm limit. During this review process, however, the District explained that prior to the issuance of the ERC, the District had consulted with U.S. EPA in relation to a different banking action, and U.S. EPA had advised the District by letter "*actual emission reductions are required to be surplus of any other SIP requirement the source is subject to, not the requirement of other agencies SIPs which do not apply to the source.*"

## IV. Part 3: Examining the District's Federal Offset Equivalency Demonstration

This section describes the District's federal offset equivalency demonstration and presents the analysis and findings of staff's review.

Summary of findings:

- The District's equivalency database is not a self-contained, relational database and lacks a complete data dictionary and technical documentation. CARB staff noted a number of stranded records, data-handling discrepancies, and transparency concerns related to these issues.
- The District over-credited the amount of emission reductions claimed for equivalency from PG&E's AG-ICE diesel-to-electric incentive program for agricultural irrigation pumps (Table 13). The over-credit is due to the use of a load factor of 1.0 instead of the Carl Moyer Guidelines' recommended load factor of 0.65 in the calculation of the amount of actual emission reductions creditable from these projects. (Table 11).
- Six of the ten AG-ICE projects reviewed received Carl Moyer co-funding, which, according to California Health and Safety Code section 44281(b) and Carl Moyer Guidelines, call into question their appropriateness for use in the equivalency demonstration. However, CARB staff found no evidence that the emission reductions from the AG-ICE projects were relied on in the California State Implementation Plan (SIP), which indicates the District's use of these reductions likely did not result in double-counting in both the SIP and equivalency demonstration, and found evidence that only a portion of the reductions, and not all of the reductions, were claimed for offset equivalency.
- AG-ICE projects were emission reductions from agricultural sources and not all agricultural sources were/are subject to permitting and NSR. Pursuant to SB 700 (2003, Florez), the District requires permits for agricultural sources (including spark- and compression-ignited irrigation pumps) if their emissions are greater than one-half of the major source emissions threshold. For agricultural sources with emissions less than one-half of the major source emissions threshold, the District issues registrations for spark- and compression-ignited irrigation pumps. It is unclear whether the emission reductions associated with the AG-ICE projects met the enforceability and permanence criteria under Rule 2201 Sections 7.2.2.2 and 7.1.5 in all cases.
- The District over-credited the amount of NOx and VOC emission reductions from some orphan shutdowns claimed for surplus-at-time-of-use equivalency for ten of the eleven projects reviewed (Table 14). Collectively, orphan shutdowns account for nearly 50 percent of the emission reductions the District used to

show surplus-at-time-of-use equivalency for VOC from 2001 – 2018 and over 60 percent of the excess VOC and NOx emission reductions available for use in future equivalency demonstrations at the end of the 2018 reporting period (Table 12).

A. Equivalency Overview

Since 2001, U.S. EPA has required the District to demonstrate program equivalency with federal NSR offset requirements by showing that the emissions reductions generated by SJVAPCD's NSR requirements as a whole are equal to or greater than the reductions that would have been required by federal NSR.[26] U.S. EPA and the District entered into an agreement on August 30, 1999 establishing the requirements for the equivalency demonstration. The District subsequently amended its NSR rule (District Rule 2201), to reflect the requirements of the agreement. The equivalency provisions in Rule 2201 have been incorporated into the SIP, and through that process were subject to CARB review and U.S. EPA approval. The District submits its federal offset equivalency report each November to U.S. EPA and CARB. The reports are available on the District's web site. The reports provide a summary of the reductions the District relies on to demonstrate equivalency, but the full data set underlying the equivalency demonstration is within the District's internal equivalency tracking system, which is not subject to regular review by U.S. EPA or CARB.

The federal offset equivalency demonstration consists of two distinct tests: Test 1 (offset requirement equivalency) and Test 2 (surplus-at-time-of-use equivalency).

Test 1 – offset requirement equivalency – compares the annual quantity of offsets that would have been required under the federal program (i.e., the "Federal offset quantity" or FOQ) to the annual quantity of offsets actually required by the District's program (i.e., the "District offset quantity" or DOQ).[27] This test requires the District to calculate and track the total FOQ and DOQ from all ATC projects it issues each period. To demonstrate equivalency under this test, the total DOQ must be equal to or greater than the total FOQ.

Although the District is required to report this demonstration annually, the report is best understood as an update because the District must demonstrate equivalency since August 20, 2001. In other words, when the District makes an equivalency

[26] Technical Support Document for EPA's Notice of Proposed Rulemaking for the California State Implementation Plan, San Joaquin Valley Unified Air Pollution Control District: Rule 2020, Exemptions Rule 2201, New And Modified Stationary Source Review Rule, p. 15 - 17 (8/30/1999); *see also* August 26, 1999 Letter from David Howekamp, U.S. EPA Region IX Director Air Division to Mark Boese, Deputy APCO, SJVAPCD, enclosing EPA-District NSR Offset Tracking Agreement.

[27] The abbreviations FOQ and DOQ will be used to represent the federal and district offset quantities both for individual ATC projects and the total for all ATC projects during a tracking period. The context will make clear which meaning is intended.

demonstration, it represents federal offset equivalency over the life of the NSR program since 2001. Thus, in Test 1 (the offset requirement equivalency test), any extra DOQ beyond what is needed to show equivalency with the FOQ in the current year's equivalency demonstration may be carried forward and used to show equivalency in future years if the ATC projects issued in that year show a shortfall in DOQ relative to the FOQ.

While Test 1 is focused on the amount of offsets required, Test 2 is focused on the emission reductions used to satisfy the offset requirements.

Test 2 – surplus-at-time-of-use equivalency – requires the District to reserve or retire sufficient surplus-at-time-of-use creditable emission reductions[28] to mitigate the current years' FOQ plus any unmitigated FOQ from prior years.[29] The creditable emission reductions the District uses to mitigate the FOQ can be drawn from any time from August 20, 2001, the start of the tracking system, to the end of the current tracking period. The creditable emission reductions used to satisfy the FOQ have come from three principle sources: (1) ERCs reserved or withdrawn for ATC projects, (2) orphan shutdowns, and (3) electrification of agricultural irrigation pump engines from 2005 – 2008.[30]

Each test has its own accounting rules and different remedies for a failure to demonstrate equivalency. The failure of one test would not necessarily entail failure of the other. Both tests are pollutant specific, meaning equivalency must demonstrated for every pollutant (i.e. NOx, VOC, PM10, PM2.5, CO, and SOx). Because the demonstration represents federal offset equivalency over the life of the program since 2001, both tests permit the District to carry forward any excess or shortfall in credit for use in a future year's equivalency demonstration. The District has an excess margin of credits to draw on to remedy future potential shortfalls for both tests. That substantial margin of excess credits, however, rests on the integrity of the prior credits used for equivalency.

Because almost all NMSs and FMMs in SJVAPCD involve NOx and VOC offsets, CARB's review of SJVAPCD's federal offset equivalency demonstration focused on NOx and VOC.

[28] A creditable emission reduction meets the same integrity criteria as ERCs, i.e. the emission reductions must be real, quantifiable, permanent, enforceable, and surplus.
[29] The District has never had a year where it did not fully mitigate the current tracking year's FOQ based on the data provided in the District's equivalency demonstration reports.
[30] PG&E's Ag-ICE program will be discussed in detail in Part III. C. 3. a. See Tables 13 and 14 for the total amount of reductions claimed for NOx and VOC equivalency by type.

B. Interpreting the District's Federal Offset Equivalency Report

The District must submit to U.S. EPA and CARB its annual federal offset equivalency report by November 20 every year.[31] The District publishes the equivalency reports on its web site.[32] Each report summarizes the offsetting and emissions reduction (i.e. mitigation) activity during the tracking period August 20 of the previous year to August 19 of the current year. The dates coincide with the effective date of the equivalency demonstration requirements in SJVAPCD's NSR Rule 2201 on August 20, 2001. The report summarizes the activity during the tracking period. The determination of equivalency in the report reflects not only that current year's activity, but also the entire history since the beginning of the tracking system in 2001. Table 3 is reproduced from SJVAPCD's 2019 Annual Offset Equivalency Report for the tracking period 8/20/2018 to 8/19/2019 and summarizes the demonstration of equivalency made for Test 1.

**Table 3 : Test 1 – Offset Requirement Equivalency (from SJVAPCD 2019 Annual Offset Equivalency Report)**

| Pollutant | Number of New Federal Major Sources (NMS) | Number of Federal Major Modifications (FMM) | Offsets Required under Federal NSR (FOQ) (tons per year) | Offsets Required under District NSR (DOQ) (tons per year) | Excess or Shortfall This Year (tons per year) | Excess or Shortfall Previous Year (tons per year) | Total Excess or Shortfall (tons per year) |
|---|---|---|---|---|---|---|---|
| NOx | 0 | 16 | 83.4 | 84.4 | 1.0 | 4,312.9 | 4,313.9 |
| VOC | 0 | 19 | 69.5 | 43.3 | -26.2 | 733.4 | 707.2 |
| PM10 | 0 | 0 | 0.0 | 3.2 | 3.2 | 837.5 | 840.7 |
| PM2.5 | 0 | 0 | 0.0 | 0.0 | 0.0 | 377.7 | 377.7 |
| CO | 0 | 0 | 0.0 | 0.0 | 0.0 | 198.1 | 198.1 |
| SOx | 0 | 0 | 0.0 | 47.5 | 47.5 | 2,863.6 | 2,911.1 |

The equivalency test is performed pollutant-by-pollutant. In 2019, for NOx, there were 16 FMM, which required 83.4 tons per year of NOx reductions under federal requirements. Thus, 83.4 tons per year is the FOQ. The actual quantity of offsets or DOQ required by SJVAPCD for all ATC projects issued during the tracking period was 84.4 tons per year NOx. Therefore, SJVAPCD required 1.0 tons per year more NOx offsets under their NSR rule than they would have required if they were following federal NSR to determine the offset quantity. The extra 1.0 tons per year is added to the accumulated 4,312.9 tons per year of excess NOx accumulated from prior years, and is carried forward for use in future years. As long as the Total Excess (last column of Table 4) is equal to or greater than 0.0 tons per year, SJVAPCD has shown it meets

[31] Rule 2201, 7.3.2 (amended 8/15/19)
[32] http://www.valleyair.org/busind/pto/annual_offset_report/annual_offset_report.htm

Test 1 "offset requirement equivalency" for NOx as of the end of the tracking period. Moreover, the Total Excess NOx (4 313.9 tons per year) is available to use for future Test 1 equivalency demonstrations when the FOQ is larger than the DOQ in a future year.

Table 4 is reproduced from SJVAPCD's 2019 Annual Offset Equivalency Report for the tracking period 8/20/2018 to 8/19/2019 and summarizes the demonstration of equivalency made for Test 2.

**Table 4: Test 2 – Surplus at the Time-of-Use Equivalency (from SJVAPCD 2019 Annual Offset Equivalency Report)**

| Pollutant | Number of New Federal Major Sources | Number of Federal Major Mods | Offsets Required under Federal NSR (FOQ) (tons per year) | Shortfall from previous year (tons per year) | Reduction (surplus at the time of use) used for equivalency this year (tons per year) | Shortfall this year (tons per year) | Reductions eliminated by discounting at the time of use (tons per year) | Unused Carry-over Creditable Reductions (tons per year) |
|---|---|---|---|---|---|---|---|---|
| NOx | 0 | 16 | 83.4 | 0.0 | 83.4 | 0.0 | 5,559.8 | 408.0 |
| VOC | 0 | 19 | 69.5 | 0.0 | 69.5 | 0.0 | 2,300.3 | 1,428.0 |
| PM10 | 0 | 0 | 0.0 | 0.0 | 0.0 | 0.0 | 135.0 | 1,898.0 |
| PM2.5 | 0 | 0 | 0.0 | 0.0 | 0.0 | 0.0 | 8.4 | 1,020.0 |
| CO | 0 | 0 | 0.0 | 0.0 | 0.0 | 0.0 | 110.7 | 763.0 |
| SOx | 0 | 0 | 0.0 | 0.0 | 0.0 | 0.0 | 786.6 | 2,038.0 |

Similar to Test 1, Test 2 is performed on a pollutant-by-pollutant basis. The first three columns for Test 2 are the same as for Test 1. During the 2019 tracking period, the FOQ was 83.4 tons per year of NOx. The current years' FOQ is added to the shortfall from the previous year (in this case zero) to get the total amount of surplus-at-time-of-use emission reductions the District must reserve, withdraw, or retire to show equivalency. The District mitigated or matched the 83.4 tons per year NOx FOQ with 83.4 tons per year NOx worth of surplus-at-time-of-use reductions as indicated in the column "Reduction (surplus at the time-of-use) used for equivalency this year." The District identifies the amount and source of those reductions in an attachment to the report. The sources of the NOx reductions for 2019 are from ERCs and orphan shutdowns. Since the District was able to match the FOQ with enough surplus-at-time-of-use reductions based on its calculations, the District does not have any shortfall in 2019, which means it has passed Test 2. In the column "Reductions eliminated by discounting at time-of-use," the District presents the sum total since 2001 of reductions required by its NSR program that were not surplus and so were not counted as mitigation in Test 2. Finally, the last column, "Unused carry-over creditable reductions" are the excess reductions still available for use in next year's surplus-at-time-of-use demonstration.

C. Equivalency Review Approach

The District's offset equivalency demonstration is complex and involves large and diverse data sets, covering a nearly 20-year period. CARB staff evaluated the data system functionality, approaches, and calculations in order to evaluate the equivalency determination. Staff reviewed both the data system as a whole and individual projects, selected at random, which were part of the equivalency demonstration. To conduct the evaluation, staff reviewed the District's equivalency database and associated documentation including individual tables, inputs to the database, and outputs from the database. Staff reviewed select reduction types and the underlying source data to determine whether it was correct and accurately input to the database system. The purpose of the evaluation was to determine whether the equivalency database is accurately reporting information and calculating equivalency.

*1. Findings Regarding the Equivalency Database*

The equivalency database is a system written in Microsoft Access, and originally developed in the mid-2000s. Overall, the database's lack of documentation limits the ability to determine if the system is functioning properly. In addition, the database is not self-contained, meaning that many calculations are conducted external to the database system (e.g., input from spreadsheet files), and not adequately documented in the database. This impedes the ability to assure the quality of the calculations in the demonstration.

To facilitate the review, District staff provided CARB staff with access to the database in the District's Fresno office, along with a manual describing how to operate the system, including copying and clearing data tables, renaming the tables, performing analyses in Microsoft Excel, and inputting data from Excel to Microsoft Access. District staff also provided a partial data dictionary based on specific CARB requests. CARB staff created copies of two summary tables in the database (Track_Master and Track_Allocate). These tables represent the results of core calculations and information tracked and used in the database system. District staff could not provide a complete data dictionary or technical documentation describing the calculations within the system.

The Track_Master table is the parent table for the Track_Allocate table. They are connected through the TrackNum field in each table. Each time a portion of an ERC is allocated (used), a record is put in the Track_Allocate table and the quantity of the ERC used is in the quantity column of the Track_Allocate table. Based on this understanding, there should never be a record in the Track_Allocate table that does not have a parent record in the Track_Master table. Otherwise, referential integrity is not enforced in the database. CARB staff's analysis identified what appear to be orphan records, including 194 NOx and 98 VOC records in Track_Allocate that did not have a record in Track_Master.

The used_NOx and used_VOC fields in Track_Master represent the amount of NOx and VOC used from an ERC (or other creditable reduction) in the surplus-at-time-of-use equivalency demonstration. This amount should always be less than or equal to the total value of the Actual Emission Reductions (AER), which is shown in the aer_NOx and aer_VOC fields. As a result, the used_NOx and used_VOC fields should always be less than or equal to the aer_NOx and aer_VOC fields. CARB's analysis identified 6 records where the used_VOC exceeded the aer_VOC, although the difference was negligible (0.122 t/y VOC).

District staff has investigated and identified the source of most of the discrepancies identified by CARB staff and have committed to making the appropriate corrections immediately. District staff has also conveyed their assurance that none of the orphan records identified above had any effect on the equivalency demonstration. Finally, District staff has indicated a willingness to explore the development of a new database with documentation to reduce the types of issues noted above and improve transparency.

*2. Findings Regarding Test 1 – Offset Requirement Equivalency*

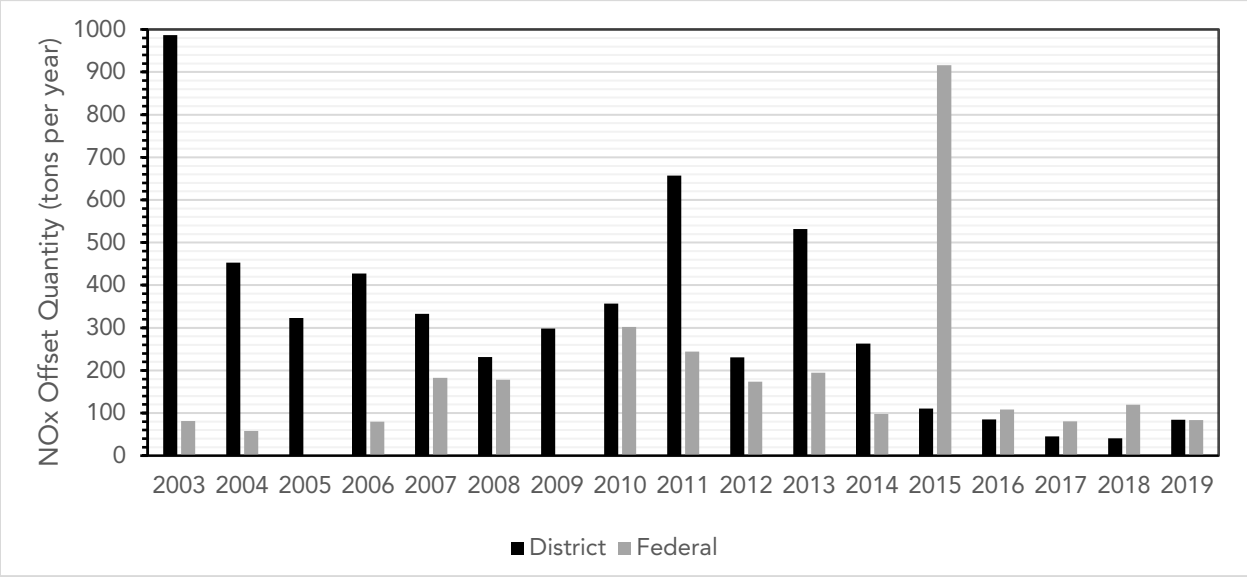
Figures 5 and 6 compare the DOQ to the FOQ for all ATCs issued by tracking year.[33] Between 2001 and 2010, the District's NSR program required more offsets for NOx and VOC than what would have been required by the federal NSR program, primarily because the District required offsets at a lower emissions threshold than federal NSR during that time. However, after the bump-up to extreme non-attainment for ozone in 2010, the FOQ usually tends to be greater than the DOQ for NOx and VOC for the ATCs issued in a given year.

Overall, the database indicates the District has accumulated a significant excess DOQ for every pollutant from previous years' equivalency demonstrations. The most current statement of the amount of excess credits the District has for Test 1 is from the District's 2019 equivalency report, presented in Table 3 in the last column labeled "Total Excess or Shortfall". A positive number indicates an excess, a negative number, a shortfall. The Total Excess DOQ for NOx is 4,313.9 tons per year, for VOC 707.2 tons per year. This will be the starting point for the District's equivalency demonstration in 2020.

CARB identified a transparency issue associated with the equivalency demonstrations each year. In essence, the carryover from year-to-year relies on adjustment terms that are not clearly provided in the tables, and which are difficult to check.

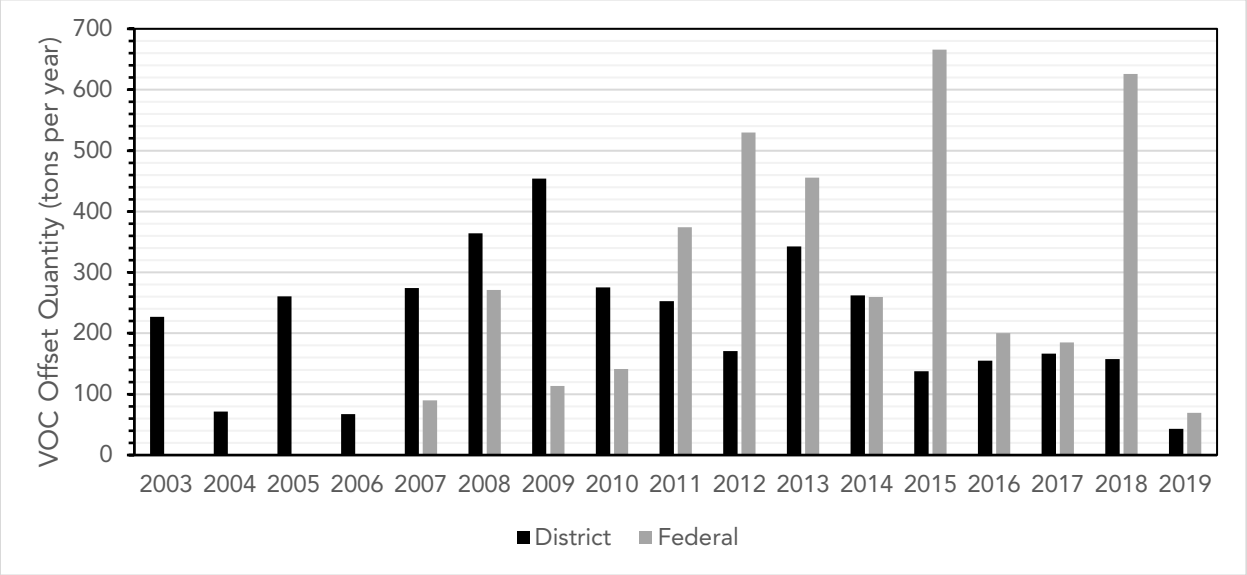
[33] A given tracking period runs from August 20 of one year to August 19 of the following year. The tracking year is the later year in this period. For example, for the tracking period running from August 20, 2015 to August 19, 2016, the tracking year is 2016.

## Figure 5. NOx District Offset Quantity and Federal Offset Quantity by Tracking Year




**Source: SJVAPCD Equivalency Reports Published on http://www.valleyair.org/busind/pto/annual_offset_report/annual_offset_report.htm**

## Figure 6. VOC District Offset Quantity and Federal Offset Quantity by Tracking Year




**Source: SJVAPCD Equivalency Reports Published on http://www.valleyair.org/busind/pto/annual_offset_report/annual_offset_report.htm**

The quantities displayed in Figures 5 and 6 are taken from each individual annual equivalency demonstration. The Total Excess or Shortfall values in the 2019 Report (Table 3) consists of the sum of the DOQs and FOQs from all previous equivalency reports plus adjustments for any projects removed (or sometimes added to) the tracking system each year. Simply adding quantities displayed in Figures 5 and 6 will not equal the Total Excess DOQ, which takes into consideration the annual adjustments related to projects being removed or added to the tracking system. The necessary adjustment is not explicitly stated in the tables but its cumulative effect over all the years is significant.

These adjustments come from ATC projects that previously were included in the tracking system in one year, but for various reasons (usually the ATCs have been cancelled or expired unimplemented), it becomes necessary to remove them. In the annual equivalency reports published by the District since 2011, the District lists the ATC projects that are being removed from the current year's demonstration and provides a reason for the removal. For example, the adjustment taken in the 2019 Equivalency Report is summarized in Table 5.

CARB staff attempted to verify the net adjustment in Table 4 above by summing the net effect from the three ATC projects removed from the 2019 Equivalency Demonstration (Table 5). In Table 5, removal of a project from the tracking system is accompanied by a negative sign in the corresponding DOQ and/or FOQ value. CARB staff found the DOQ and the FOQ from the ATC application reviews of the three projects on the District's public notification web site. The ATC application reviews are the source documents for the DOQ and FOQ that are used for the equivalency demonstration. CARB staff calculated a net adjustment of +0.5 tons per year for NOx and +22.3 tons per year for VOC, compared to the District's adjustment of +35.4 tons per year for NOx and +77.3 tons per year for VOC.

**Table 5. Adjustment to Excess DOQ Credit Implied in SJVAPCD 2019 Equivalency Report**

| | NOx DOQ (tons per year) | VOC DOQ (tons per year) |
|---|---|---|
| Total Excess from 2018 Report (ending) | 4,277.5 | 656.1 |
| Total Excess from 2019 Report (beginning) | 4,312.9 | 733.4 |
| Net Adjustment | +35.4 | +77.3 |

**Table 6. CARB Calculated Adjustment to Excess DOQ Credit from 2019 Project Removed List**

| Project Number removed | NOx DOQ (tons per year) | NOx FOQ (tons per year) | VOC DOQ (tons per year) | VOC FOQ (tons per year) |
|---|---|---|---|---|
| C-1133313 | 0 | 0 | -13.7 | -13.7 |
| C-1161110 | 0 | -0.5 | 0 | 0 |
| N-1133659 | 0 | 0 | -41.5 | -63.8 |
| Total Adjustments | 0 | -0.5 | -55.2 | -77.5 |
| CARB Net Adjustment | +0.5 | | +22.3 | |
| District Net Adjustment | +35.4 | | +77.3 | |
| Discrepancy | +34.9 | | +55.0 | |

District staff has explained that the source of the NOx difference was related to ATC project N-1161175 from the 2017 – 2018 tracking period, which had a DOQ of 35.0 tons per year NOx. According to District staff, the District included the FOQ for this project during the 2017 – 2018 tracking period, but not the DOQ because the facility had not specifically identified which ERC certificates it was going to use to satisfy the DOQ. The facility did identify which specific NOx ERCs it would use as offsets during the 2018 – 2019 tracking period, at which point the District added the DOQ amount as a 35.0 tons per year NOx adjustment. District staff has indicated verbally a similar explanation for the VOC difference noted in Table 6 above.

In effect, the District delayed counting the DOQ, is conservative and understandable under the circumstances, and had no impact to the outcome of equivalency demonstration. However, this explanation should have been included in the list of projects accounting for the adjustment in the 2018 – 2019 report – so that the report and calculations are more clear to the interested public, CARB, and U.S. EPA.

CARB staff also checked the District's calculations of the DOQ and FOQ by examining the ATC application reviews for the 2016 - 2017 tracking period. The ATC application reviews are the building blocks for the equivalency demonstration. The FOQ and DOQ values provided in the equivalency reports -- on which the determination of equivalency rests -- should be traceable back to the ATC application reviews. CARB staff obtained from the District and the District's web site the application reviews for the ATC projects from the 2017 tracking year (8/20/2016 – 8/19/2017) that were identified as NMS (1 ATC project) or FMM (32 ATC projects). Most ATC projects that had a FOQ also had a DOQ. For example, of the 14 ATC projects that were FMM for NOx, 11 also had a DOQ associated with the project.

Staff spot-checked the emissions increase calculations used to determine the FOQ and the DOQ in the ATC application reviews for all the NMS (1) and FMM (32) projects identified by the District for the 2017 tracking year. All reviewed calculations appeared to have been completed correctly. Staff then summed the FOQ and DOQ from all the ATC application reviews in order to compare to values reported by the District in the 2017 report. These results are summarized in Tables 9 and 10 below.

Table 7 shows a minor discrepancy discovered between the calculated and reported FOQ for VOC. The source of this discrepancy is ATC projects S-1151973 and S-1152366, which were associated with a FOQ of 7.9 tons per year VOC. However, the District entered the FOQ as 5.3 tons per year VOC for these projects (in the ini_i_VOC field of the Track_Master table). This results in a difference in the FOQ of 2.6 tons per year VOC. Thus, CARB staff calculated a FOQ of 187.6 tons per year VOC, while the district reported a FOQ of 185.0 tons per year VOC.

**Table 7. Comparison Between CARB Calculated and SJVAPCD Reported Federal Offset Quantities for One New Major Source and 32 FMMs Reported in the 2017 Equivalency Demonstration.**

| FOQ Calculation Method | NOx (tons per year) | VOC (tons per year) |
|---|---|---|
| FOQ calculated using CARB reviews of each NMS and FMM | 80.5 | 187.6 |
| FOQ reported in the 2017 Equivalency Report | 80.5 | 185.0 |
| FOQ calculated in the Equivalency Database Track_Master table. | 80.5 | 185.0 |

Verification of the DOQ for Test 1 must take account of a different subset of ATC projects because the District can require offsets (DOQ) both from projects that are NMS or FMM and from new minor sources or minor modifications. CARB staff reviewed ATC application reviews for all the NMS (1) and FMM (32) identified by the District for the 2017 tracking year to identify the DOQ. However, staff did not request the ATC application reviews for those projects that had a DOQ but were not NMS or FMM. The DOQ from those projects was taken at face value from Track_Master.

Staff added up the DOQ from FMM, NMS, and minor projects. Table 8 shows the results of this analysis, by comparing differences between the CARB calculated DOQ and District reported DOQ for NOx and VOC from the 2017 Report. CARB staff identified 75.9 tons per year NOx DOQ from FMM and NMS, and 0.8 tons per year from minor projects, for a total of 76.7 tons per year NOx DOQ. However, the District in its 2017 Equivalency Demonstration, presented a DOQ of 45.6 tons per year NOx – a difference of 31.1 tons per year NOx from the CARB value.

CARB staff identified 100.2 tons per year VOC DOQ from FMM and NMS, and 119.2 tons per year VOC DOQ from minor projects for a total of 219.4 tons per year VOC DOQ. However, the District in its 2017 Equivalency Demonstration, presented a DOQ of 166.8 tons per year VOC DOQ – a difference of 52.6 tons per year VOC from the CARB value.

**Table 8. Comparison between CARB Calculated and SJVAPCD Reported District Offset Quantities in the 2017 Equivalency Demonstration**

| DOQ Calculation Method | NOx (tons per year) | VOC (tons per year) |
|---|---|---|
| DOQ calculated using CARB reviews of each NMS and FMM | 75.9 | 100.2 |
| DOQ from minor projects in Track_Master | 0.8 | 119.2 |
| Total DOQ | 76.7 | 219.4 |
| DOQ reported in the 2017 Equivalency Report* | 45.6 | 166.8 |
| Possible under-credit of DOQ | 31.1 | 52.6 |

*The source of the DOQ in the equivalency report is sum of erc_pollutant fields in Track_Master.

CARB staff identified ATC projects whose application reviews identified a DOQ, but had a different value noted in the erc_NOx field in Track_Master (Table 9). The erc_NOx field in Track_Master is the source for the DOQ in the equivalency reports.

**Table 9. List of ATC Projects from 2017 Report with a District Offset Quantity for NOx in the Authority to Construct Application Review Different from what is Recorded in the Equivalency Database (as erc_nox)**

| ATC Project Number | DOQ for NOx (tons per year) in ATC Application Review | erc_NOx (tons per year) from Track_Master* |
|---|---|---|
| S-1143503 | 1.1 | 0 |
| S-1144548 | 32.6 | 33.2** |
| S-1151973 (and S-1152366) | 18.4 | 0.0000001 |
| S-1162420 | 8.5 | 0.0000001 |
| S-1162746 | 0.3 | 0.2 |
| S-1170679 | 0.3 | 0.2 |
| S-1171052 | 0.9 | 0.1 |
| S-1171635 | 6.9 | 4.1 |
| Net Difference | +31.2 | |

* Each ERC certificate reserved or withdrawn for a given ATC project will have its own separate entry (erc_NOx) in the District's Track_Master equivalency database under erc_NOx (or erc_pollutant more generally). The DOQ for each ATC project in Table 9 could represent more than one ERC certificate.

** Both District and CARB staff agree that the erc_nox value for project S-1144548 should be 32.6 tons per year. 33.2 tons per year is the total face value of the NOx ERCs proposed for use as offsets in project S-1144548, not the DOQ.

Finally, CARB staff noted three examples where the DOQ for individual ATC projects appeared to be over-credited because the face value of the ERCs reserved for an ATC project were counted (in erc_nox field of Track_Master) instead of the actual DOQ calculated in the application review. This is shown in Table 10. District staff has acknowledged these issues and assured CARB staff that they would be corrected.

**Table 10: ATC projects where the DOQ was Over-credited in the Report Because the Face Value of the ERCs Instead of the DOQ from the ATC Application review was Transferred to erc_nox in Track_Master***

| Report year | ATC project | erc_nox from Track_Master (tons per year) | ERC # from ATC application review | Face value of ERC (tons per year) | Amount of NOx offset required in ATC project (tons per year) | Over-credit to DOQ in Test 1 Demonstration [sum of erc_nox – amount of offset required in ATC project] |
|---|---|---|---|---|---|---|
| 2017 | S-1144548 | 33.2 | S-3208-2 | 33.2 | 32.6 | 0.6 |
| - | - | - | - | - | - | - |
| 2016 | S-1151996 | 5.7 | S-4515-2 | 5.7 | 7.4 | 7.6 |
| 2016 | S-1151996 | 1.4 | S-4514-2 | 5.8 | | |
| 2016 | S-1151996 | 0.5 | S-4516-2 | 0.5 | | |
| 2016 | S-1151996 | 3.7 | S-4530-2 | 3.7 | | |
| 2016 | S-1151996 | 1.5 | N-1302-2 | 1.5 | | |
| 2016 | S-1151996 | 2.2 | N-1332-2 | 2.2 | | |
| - | - | - | - | - | - | - |
| 2016 | S-1153671 | 0.4 | S-3326-2 (?) | 0.4 | 6.8 | 6.6 |
| 2016 | S-1153671 | 1.2 | S-3625-2 | 1.2 | | |
| 2016 | S-1153671 | 0.7 | N-1327-2 | 0.7 | | |
| 2016 | S-1153671 | 0.4 | N-1329-2 (?) | 0.4 | | |
| 2016 | S-1153671 | 10.7 | C-1059-2 | 4.1 (?) | | |

Overall, CARB staffs' review of federal offset equivalency identifies issues with the accuracy and transparency of the equivalency demonstration because of the data handling system, which, for reasons noted in the findings on the equivalency database, makes it difficult to ensure the accuracy of the demonstration. The current data handling system may have been adequate when the District began the tracking system in 2001 until 2010 -- when the number of NMS and FMM projects in a tracking period

was between zero to four for every pollutant. However, after the bump-up to extreme non-attainment for ozone in 2010, the number NMS and FMM projects for NOx and VOC together has ranged from 35 to 90 every tracking period, creating a quality assurance challenge in an already complex system. The data handling issues point to a clear need for better quality control and transparency.

*3. Findings Regarding Test 2 – Surplus at Time-of-Use Equivalency*

The second federal offset equivalency test requires the District to reserve or retire sufficient surplus-at-time-of-use creditable emission reductions to mitigate the current years' FOQ. In other words, the District must demonstrate that it has retired sufficient reductions valued as surplus-at-time-of-use to match the number of reductions that would have been required under federal NSR. The emission reductions used as mitigation may come from any year since the start of the equivalency tracking system in 2001, and, as such, each annual report represents a running-total demonstration of equivalency.

The "surplus-at-time-of-use" federal requirement is based in the Clean Air Act requirements that all creditable emission reductions be surplus to all requirements under the Act. Further, this valuation is necessary to avoid double counting of reductions claimed in the SIP.[34] As U.S. EPA has explained ". . . the State cannot rely on emission reduction credits in its overall attainment plan and rely on the same credits in the issuance of an NSR permit (i.e., no 'double counting')."[35] U.S. EPA requires Test 2 as part of the equivalency demonstration because SJVAPCD relies on surplus-at-time-of-issuance valuation and does not discount the value of ERCs at time-of-use based on additional requirements that have been imposed between issuance and use.[36]

Performing a surplus-at-time-of-use determination for an ERC requires looking back at the original emission reduction, but applying the strictest applicable law or emission standard in effect at the time the ERC is used as an offset for NSR (i.e., at time of ATC issuance). As the emission standards become more stringent, the amount of the

[34] See footnotes 9 and 10.

[35] July 21, 1993 U.S. EPA Memorandum from John Seitz, Director, Office of Air Quality Planning and Standards to Air Branch Chiefs, Regions I-X, et al., "Use of Shutdown Credits for Offsets."; *see also* August 26, 1994 U.S. EPA Memorandum from John Seitz, Director, Office of Air Quality Planning and Standards, to David Howekamp, Director Region IX, Air and Toxics Division: "Response to Request for Guidance on Use of Pre-1990 ERC's and Adjusting for RACT at Time-of-use."

[36] Bay Area AQMD and Ventura County APCD are required to perform similar surplus-at-time-of-use equivalency demonstrations by U.S. EPA because they likewise only require emission reductions banked as ERCs to be surplus-at time-of-issuance. South Coast AQMD also does not discount ERCs for their time-of-use; however, South AQMD discounts emission reductions banked as ERCs to applicable Best Available Control Technology (BACT) levels at time-of-issuance. South Coast AQMD is required by U.S. EPA to make an annual demonstration of federal offset equivalency for emission reductions held in its internal bank per Rule 1315, Federal New Source Review Tracking System.

original emission reduction that is still surplus will be reduced. In aggregate, the requirement that ERC value be determined at time-of-use has a deflationary effect on the offset value of an ERC bank.[37] This is discussed in Part 1, which illustrates that the District's estimate that its NOx ERC bank's time-of-use value (as of 2016) is on average about 18 percent of its time-of-issuance value.

Test 2 requires the District to match or mitigate the federal offset quantity (FOQ) from the current tracking period with an equal amount of surplus-at-time-of-use emission reductions drawn from an "equivalency bank" of creditable emission reductions. These reductions are not formally banked, but rather tracked by the District internally through its equivalency-tracking database. To be "creditable" means an emission reduction is real, surplus,[38] quantifiable, enforceable, and permanent.[39] Rule 2201 further defines the eligibility criteria for use of such reductions in the equivalency demonstration.[40]

In practice, the District has used the following types of creditable emission reductions in its "equivalency bank" for use in the surplus-at-time-of-use equivalency demonstration:

- ERCs reserved or withdrawn for ATC projects,
- Unclaimed reductions from orphan shutdowns (i.e. closed facilities), [41]
- Electrification projects from PG&E's AG-ICE program,
- 10 percent air quality improvement deduction (AQID) from newly banked ERCs, returned credits from unimplemented NMS and FMS,
- ERCs surrendered for non-NSR actions (e.g. CEQA, variance, consent decree),

As with Test 1, Test 2 allows any excess in the amount of surplus-at-time-of-use creditable emission reductions to remain in the equivalency bank and be carried forward to future years for equivalency purposes.

To evaluate Test 2, CARB staff began by spot-checking the emission reduction calculations for the types of reductions that have been the most significant for the surplus-at-time-of-use equivalency demonstration. Table 11 compares the amount of NOx reductions used, and the amount remaining for future use in equivalency demonstrations, over the period 2001-2018. Table 11 shows that electrification

[37] The surplus value of the ERC at time-of-use could vary from 0 to 100 percent of its face value. In a April 19, 2016 draft staff report on its equivalency system, SJVAPCD estimated that approximately 18 percent of its banked NOx ERCs were currently surplus (ref. http://www.valleyair.org/Workshops/postings/2016/05-11-16_OEI/DRAFT-Staff-Report.pdf)
[38] For purposes of Test 2, surplus is understood to mean "at time-of-use," i.e. when the creditable reduction is used for a mitigation.
[39] Rule 2201, section 7.1.5.
[40] Rule 2201, section 7.2.2.2.
[41] The electrification projects discussed later in this review could be classified as a type of orphan reduction that the generator of the reduction did not claim or ceded to the District.

projects have accounted for more than 50 percent of the mitigations used to show surplus-at-time-of-use equivalency for NOx from 2001 to 2018, and were completely used by the end of the 2017 to 2018 tracking period. Table 12 shows orphan shutdowns have accounted for nearly 50 percent of the mitigations used to show surplus-at-time-of-use equivalency for VOC from 2001 to 2018 and comprise over 60 percent of the excess VOC and NOx mitigations available for use at the end of the 2018 reporting period.

**Table 11: NOx Reductions Used and Remaining by Type for Surplus-at-Time-of-Use Equivalency 2001 – 2018. (All values are tons per year from Track_Master Table.)**

| Type of Reduction | Amount Used as Mitigation (used_nox) | Remaining Reductions Available for Future Equivalency Demonstrations (r_nox) |
|---|---:|---:|
| Emission Reduction Credits | 720.7 | 160.6 |
| Electrification Projects | 1,210.7 | 0 |
| Orphan Shutdowns | 122.5 | 273.8 |
| Totals | 2,053.9 | *434.4 |

*Unused Carry-Over Reductions in 2018 Report = 434.0 tons per year NOx

**Table 12: VOC Reductions Used and Remaining by Type for Surplus-at-Time-of-Use Equivalency 2001 – 2018. (All values are tons per year from Track_Master Table.)**

| Type of Reduction | Amount Used as Mitigation (used_voc) | Remaining Reductions Available for Future Equivalency Demonstrations (r_voc) |
|---|---:|---:|
| Emission Reduction Credits | 1,752.4 | 466.2 |
| Electrification Projects | 61.2 | 0 |
| Orphan Shutdowns | 1,720.4 | 819.2 |
| Totals | 3,534.0 | *1,285.4 |

*Unused Carry-Over Reductions in 2018 Report = 1,286.0 tons per year VOC

The source of the creditable reductions from electrification projects is the Agricultural Internal Combustion Engine or AG-ICE program, which funded replacements of diesel internal combustion engines with utility electricity to power agricultural irrigation pumps from approximately 2005 - 2008. The District's equivalency database shows that 1,210.7 tons per year of surplus NOx reductions from 919 engines were claimed from AG-ICE. The electrification projects comprise 77 percent of the mitigations used to show surplus-at-time-of-use equivalency for NOx from 2008 to 2018.

CARB reviewed data and other background information to determine the amount of creditable emission reductions from a randomly selected sample of 10 electrification projects that were listed in the 2017 Equivalency Report. The diesel internal combustion engines replaced were all Tier 0, Tier 1, or Tier 2.

Because the District claimed the reductions from all 919 diesel-to-electric projects at the same time for use in the equivalency demonstration in 2008, and all the reductions were generated by replacing diesel internal combustion engines with electric motors, the sample of 10 projects appears representative of the emission reduction calculations from all 919 projects.

*a. Electrification Projects*

There are multiple issues with the use of the electrification projects for equivalency.

- *Issues Regarding Whether Reductions Were Real, Due to Load-Factor Discrepancies*

Emission reductions from the AG-ICE electrification projects involved the replacement of Tier 0, 1, or 2 diesel IC engines with electric motor power. The reductions from AG-ICE were divided into two parts: (a) the replacement of Tier 0, 1, 2 diesel emissions to the equivalent activity with Tier 3 levels of emissions, and (b) the replacement of Tier 3 level of emissions to zero (i.e. the electric motor emissions being counted as zero).

The District used the reductions from Tier 3 emissions to zero for the equivalency demonstration. The District did not use the emissions reduction benefit from the replacement of Tier 0, 1, 2 diesel emissions to the equivalent activity with Tier 3 levels of emissions. That reduction benefit was not utilized for equivalency. To be eligible for the equivalency demonstration, an emission reduction must be creditable meaning, among other criteria, that it must be based on real or actual emissions.[42] A portion of the reductions claimed by the District from AG-ICE do not qualify as real because the calculation methodology used by the District assumed the replaced engines' operated with a load factor of 1.0 rather than the actual load or the default load factor provided by the Carl Moyer Program Guidelines.

The Carl Moyer Program ensures reductions it funds are real (and thus SIP creditable) by using calculation methods that represent real emissions. For emission reductions based on the AG-ICE program, the Carl Moyer Program Guidelines in Appendix C prescribe the following method when the engine activity level is based on annual hours of operation:[43]

[42] District Rule 2201, Section 7.1.5 (amended 8/15/19)
[43] The Carl Moyer Program Guidelines Part IV, Appendix C, 1. Calculating Annual Emissions Based on Hours of Operation, C-3 (November 17, 2005)

*Formula C-4: Estimated Annual Emissions based on hours of Operation (tons/yr):*

*Emission Factor or Converted Emission Standard (g/bhp-hr) * Horsepower * **Load Factor** * Activity (hr/yr) * Percent Operation in CA * ton/907,200g*

*The engine load factor is an indicator of the nominal amount of work done by the engine for a particular application. It is given as a fraction of the rated horsepower of the engine and varies with engine application. For projects in which the horsepower of the baseline technology and reduced technology are different by more than 25 percent, the load factor must be adjusted following formula C-5 below. It is important to understand the replacement load factor must never exceed 100 percent in cases where the reduced technology engine is significantly smaller than the baseline technology engine.*

*Formula C-5:*

*Replacement Load Factor = Default Load Factor $_{baseline}$ * hp $_{baseline}$/hp $_{reduced}$*

Moyer uses a default load factor for agricultural irrigation pumps of 0.65 as determined from historical emissions inventory.[44] The default load factors for dozens of types of off-road heavy-duty diesel engines are given in Table B-13 of the Guidelines, and those range from 0.30 to 0.78.

Following the above Appendix C method, the CARL database uses the horsepower of the electric motor in the formula C-4 above and bases the Tier 3 emission factor on the horsepower rating of the electric motor. The CARL database uses the electric motor horsepower only in conjunction with the replacement load factor in the calculation of emissions. This ensures the activity used to calculate the reduction, measured as horsepower-hours, does not increase beyond the baseline of the replaced diesel IC engine.

However, in Appendix D of the same Carl Moyer Program Guidelines, an example calculation for an AG-ICE project is given where no adjustment to the default load factor (0.65) is made although the electric motor that replaced the diesel IC engine has a horsepower that is more than 25 percent different.[45] The example calculation uses the horsepower rating of the replaced diesel IC engine in the formula C-4 above and bases the Tier 3 emission factor on the rated horsepower of the IC engine. This method likewise ensures that the activity used to calculate the reduction equals the baseline of the replaced diesel IC engine.

[44] Carl Moyer Program Guidelines, Part IV, Appendix B, Table B-13 (November 17, 2005)
[45] The Carl Moyer Program Guidelines Part IV, Appendix D, XII. Zero-Emission Technologies, Example 2, D-64 (November 17, 2005)

CARB staff believe that either of the two methods (Appendix C or Appendix D of the Carl Moyer Guidelines Part IV) is an acceptable calculation for determining the amount of actual emission reductions from an AG-ICE project. The District used the Appendix D method with one significant deviation -- the District used a load factor of 1.0 rather than the default load factor of 0.65.

Staff reviewed District calculations from the 10 sample electrification projects. Table 13 lists the variables used and the results of the calculated amount of creditable emission reductions by the District compared to the Carl Moyer Program Guidelines Appendix D and CARL (Appendix C) described above. The District calculation for the amount of creditable NOx reductions that can be claimed for these projects is higher for all 10 projects compared to either Carl Moyer method. CARB staff believes the District over-credited these 10 electrification projects by 35 percent or more because of the use of a load factor of 1.0 tied to the horsepower of the diesel engine being replaced.

**Table 13: Creditable Emission Reduction Calculations from 10 Electrification Projects[46]**

| Tracking ID | Model Year | Tier | IC Engine Horsepower | Operating Hours (hr/year) | Carl Moyer Tier 3 NOx EF (g/bhp-hr)[47] | District Calculated Reduction NOx (t/yr)[48] | Moyer Appendix D Calculated Reduction NOx (t/yr)[49] | CARL Calculated Reduction NOx (t/yr)[50] |
|---|---|---|---|---|---|---|---|---|
| 2008-S-8881142-3089-1 | 1979 | 0 | 125 | 6,800 | 2.32 | 2.2 | 1.4 | 0.8 |
| 2008-S-8881145-3090-1 | 1996 | 0 | 150 | 6,739 | 2.32 | 2.6 | 1.7 | Not in CARL |
| 2008-S-8881262-3137-1 | 2003 | 2 | 152 | 4,000 | 2.32 | 1.6 | 1.0 | 0.9 |
| 2008-C-8881814-3634-1 | 2003 | 2 | 125 | 3,000 | 2.32 | 1.0 | 0.6 | 0.5 |
| 2008-C-8881829-3637-1 | 2004 | 2 | 113 | 2,500 | 2.74 | 0.9 | 0.6 | 0.6 |
| 2008-C-8881878-3659-1 | 2004 | 2 | 139 | 4,000 | 2.32 | 1.4 | 0.9 | 0.9 |
| 2008-C-8881896-2980-1 | 2001 | 1 | 105 | 2,500 | 2.74 | 0.8 | 0.5 | Not in CARL |
| 2008-C-8881901-2908-1 | 1992 | 0 | 76 | 1,600 | 2.74 | 0.4 | 0.2 | Not in CARL |
| 2008-C-8881971-2996-1 | 2001 | 1 | 230 | 2,200 | 2.32 | 1.3 | 0.8 | 0.9 |
| 2008-C-8881972-3000-1 | 2002 | 1 | 230 | 2,200 | 2.32 | 1.3 | 0.8 | Not in CARL |
| | | | | | Sum | 13.5 | 8.5 | N/A |

[46] Supplemental calculations and tables related to the electrification projects will be included in a document on the San Joaquin Valley ERC Program Review Public Documents web page.

[47] Tier 3 Emission Factors from 2008 Carl Moyer Program Guidelines Part IV, Appendix B, Tables for Emission Reduction and Cost Effectiveness Calculations, Table B-13. The emissions factor from the 2005 and 2008 guidelines differ for some horsepower ranges. CARB staff used the guideline the District proposed.

[48] District calculation: NOx (t/yr) = BHP × **Load Factor (1.0)** × Operating Hours (hr/yr) × EF (g-NOx/bhp-hr) × 1 lb/453.6 g × 1 ton/2,000 lb

[49] CARB staff calculation following Carl Moyer Guidelines Appendix D:
NOx (tons per year) = BHP × **Load Factor (0.65)** × Operating Hours (hr/yr) × EF (g-NOx/bhp-hr) × 1 lb/ 453.6 g × 1 ton/ 2,000 lb [equation from 2005 Carl Moyer Program Guidelines Part IV, Appendix D, Examples Calculations, XII. Zero Emission Technologies. Also 2008 Carl Moyer Program Guidelines Part IV, Appendix E, Examples Calculations, VII. Agricultural Sources]

[50] CARL calculation following Carl Moyer Guidelines Appendix C:
NOx (tons per year) = BHP (ICE) × Default Load Factor (0.65) × (BHP (ICE)/HP electric motor) × Operating Hours (hr/yr) × EF (g-NOx/bhp-hr) × 1 lb/ 453.6 g × 1 ton/ 2,000 lb [modified load factor equation from 2005 Carl Moyer Program Guidelines Part IV, Appendix C.

- *Issues Regarding Permitted Sources*

To be eligible for use in the surplus-at-time-of-use demonstration an unbanked reduction must have been generated as a result of a permitting action:

> *For purposes of the demonstration described in Section 7.2.2, the comparison may also include the surplus value of additional creditable emission reductions that have not been used as offsets and have been banked or have been generated as a result of permitting actions. [Rule 2201, section 7.2.2.2]*

According to the District, none of the replaced engines from the sample of 10 projects had a permit prior to removal, nor was a permit issued for the electrified pump that replaced it. Thus, the reductions associated with the replacement engines were not generated as a result of a permitting action.

- *Issues Regarding Crediting of State-Funded Projects*

Some of the AG-ICE projects received co-funding from the Carl Moyer Program. California law prohibits the use of any project funded by Carl Moyer from being used as an emissions offset. While the District recognizes that some of the projects were co-funded by Moyer and the utilities, the District believes that because they are using only the portion of the total emission reductions generated equal to the replacement of a Tier 3 engine with an electric motor the requirements of State law are met. Aside from the funding issue, it is important to note that there does not appear to have been any double counting of emissions reductions, meaning the emissions the District claimed for use in equivalency were not counted in any other way for SIP purposes.

California Health and Safety Code, section 44281 (b) states:

> *No project funded by the [Carl Moyer] program shall be used for credit under any state or federal emissions averaging, banking, or trading program. No covered emission reduction generated by the program shall be used as marketable emission reduction credits or to offset any emission reduction obligation of any person or entity.*

The 2005 Moyer Guidelines, which are incorporated by reference under the Health & Safety code and implemented the Moyer statute at the time when the AG-ICE program was implemented, also specifically provided that the reductions from AG-ICE funded project belonged to the Carl Moyer Program if the project also received Moyer funds:

> *Carl Moyer Program applicants using the PG&E and SCE incentive programs will also have to make adjustments to the emission reduction calculations. Because to date virtually no electric agricultural pump projects have been funded through Carl Moyer Program grants, the PG&E and SCE incentive programs take credit for the emission reduction*

*between a Tier 3 engine and an electric motor.* ***As a condition of the PG&E and SCE incentive programs, these emission reductions must be donated to the Carl Moyer Program for clean air.*** *The emission reduction benefit between the replaced engine and a Tier 3 engine, may be included in the cost-effectiveness calculation to determine the grant amount. An example of this calculation is provided in Appendix D. (ref. 2005 Carl Moyer Program Guidelines, Part II, Project Criteria, Chapter XII, Zero Emission Technologies, XII-p. 5)*

The AG-ICE program operated with both funding between public utilities, and the State of California in part through the Carl Moyer program. Specifically, the Carl Moyer program funded conversion to electric pumps, and the public utilities provided line extensions and rate incentives. Joint funding was necessary because funding levels from the Carl Moyer program alone were not sufficient to entice a transition from diesel to electric agricultural pumps.

A joint settlement between the California Public Utilities Commission, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), the Office of Ratepayer Advocates, the Utility Reform Network, Agricultural Energy Consumers Association, the California Farm Bureau Federation, and the California Air Resources Board[51] in March 2005 established favorable electric rates which helped encourage the transition from diesel to electric pumps.

The District believes the record of the CPUC proceedings show that the agreement apportioned emission reductions between the utilities, the State, and the District. The District believes that under the agreement the State would retain criteria pollutant emission reductions generated by the transition between the engine being replaced and a Tier 3 engine, and the District (through the utilities) would retain criteria pollutant emission reductions from a Tier 3 engine to zero emissions. The District relied on their understanding of this agreement when deciding to use the AG-ICE emission reductions from Tier 3 to zero emissions for demonstrating offset equivalency. CARB staff does not concur with this assessment.

CARB staff has not determined the exact number of electrification projects that received Carl Moyer funding. In the sample of ten AG-ICE electrification projects using serial numbers for the replaced diesel engines along with other project specific information[52] CARB staff noted that six of the ten engines matched engine records in CARB's Clean Air Reporting Log (CARL) database strongly indicating these six projects received Moyer funding or co-funding.

[51] http://docs.cpuc.ca.gov/publishedDocs/published/Graphics/47069.PDF

[52] CARB staff does not have the serial number for all 919 diesel engines replaced as this information is not part of the District's equivalency tracking database that CARB staff has access to.

A preliminary review of the 919 electrification projects suggests that a large number of those could have also received Carol Moyer funding.

*Issues Regarding Permanency of Reductions*

Another of the criteria for claiming a reduction in the surplus-at-time-of-use demonstration is that the reductions be permanent.

The AG-ICE Program had a limited life, as explained in a July 27, 2005 document titled *Agricultural Internal Combustion (IC) Engine Conversion Incentive Program Questions and Answers*, published by PG&E, California Farm Bureau Federation, and Agricultural Energy Users Association[53]

> *Q7. Do I have to stay on the AG-ICE rate for the whole 10 years?*
>
> *A. No. You will only be required to stay on the AG-ICE rate for 12 months under Electric Rule 12. However, if you elect to leave the AG-ICE rate for a different PG&E electric tariff, you may not return to the AG-ICE rate.*
>
> *After the program expires on December 31, 2015, nothing in the AG-ICE program precludes a grower from leaving PG&E to disconnect or choose an alternative power source such as an IC engine, although there is no certainty as to the air quality regulations that will be in place at that time. The customer would still be responsible for non-passable charges if going to an alternate electrical source provided those charges are in existence at the time of departure.*

With the Carl Moyer Program, to ensure satisfaction of the permanence requirement, SIP creditability of reductions ends with the contract expiration. Similarly, with the AG-ICE program, reductions from the electrification projects may not be enforceable after the expiration of the contract, meaning, after the contract expires, they may not meet the criterion for permanence under Rule 2201, section 7.1.5 to be used in the equivalency demonstration.

*b.* Orphan Shutdowns

Orphan shutdowns are unclaimed emission reductions from facilities that have shut down and surrendered their air permits, but did not claim the actual emission reductions, if any, from the cessation of emissions. The District collects the actual emission reductions from orphan shutdowns and retires them for use in the equivalency demonstration. The District never uses emission reductions from orphan shut downs to directly offset emission increases from ATC projects.

[53] Ref. Agricultural Internal Combustion (IC) Engine Conversion Incentive Program Questions and Answers from July 27, 2005, Published by PG&E, California Farm Bureau Federation, and Agricultural Energy Users Association.

Although orphan emission reductions are not formally banked as ERCs, Rule 2201 does require them to meet the same evaluation criteria as ERCs.[54] The reductions must be real, surplus, permanent, quantifiable, and enforceable.

According to the District's internal guideline document "Offset Equivalency Step-by-Step Instructions," actual emissions reductions from orphan shutdowns are calculated using the following method:[55]

> *The database will calculate the emissions for units at the deleted facilities using the following protocol:*
>
> - *use the two most recent [Emissions Inventory] years from the past 5 years.*
> - *if both years are available, average the two*
> - *if only one year is available, use that year (no average)*
> - *if both years are blank[56], use 1/2 of the PE [potential to emit]*

The District's method for crediting emission reductions from orphan shutdowns is an attempt to treat orphan shutdowns in a manner similar to ERC banking applications by applying the concepts "baseline period" and "actual emission reductions" from Rule 2201.[57] That is, the District bases the amount of creditable emissions reductions on actual operating data from the most recent two-year period from the past five years preceding shutdown. The period immediately preceding shutdown is usually the lowest emitting period in the life of a facility. Rule 2201 and federal NSR allow a different 24-month period from the past five years if the permitting authority determines that a different 24-month period is more representative of normal operation. Therefore, in this respect, by using the most recent time period instead of the most representative operating period, the District's method for crediting orphan shutdowns is more conservative than Rule 2201 or federal NSR for crediting emission reductions.

However, the District's orphan credit procedure is less stringent than its normal ERC banking procedure or federal NSR for establishing real emissions in that it allows for use of one years' worth of data, or the use of half of the potential to emit, if no emissions inventory record is available from the previous five years. For facilities where the record on actual emissions is absent or missing, relying on some fraction of the permitted or potential to emit of a source as a way of representing actual emissions may be a reasonable practical accommodation. Unlike with ERC applications, where the applicant has an active interest in providing operating data,

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[54] District Rule 2201, section 7.1.5 (8/15/19)
[55] SJVAPCD *Offset Equivalency Step-by-Step Instructions*, III.C. Entering Deleted Facilities (C.III.6)
[56] The word "blank" implies missing or absent data. However, CARB staff would note that in practice "blank" appears to include instances of zero emissions, i.e. zero actual emissions is taken to be the same as missing data, justifying the use of ½ of the potential to emit.
[57] District Rule 2201, sections 3.2 and 3.9 (8/15/19)

the District is forced to rely on its own records of operating history to discern the actual emissions from the operation, which may be incomplete for older shutdowns. The question of whether the multiplier of half of the permitted emissions is appropriate here would require further research beyond the scope of this review. For purposes of this review, CARB staff assumed, consistent with District practice, half of the potential or permitted emissions where no emissions inventory or operating record was available.

The District does not discount or surplus the orphan shutdowns when they are added to the federal offset equivalency tracking system. This practice is indicated in their internal guidance document Offset Equivalency Step-by-Step Instructions*:* [58]

> *For deleted facilities, the District does not discount the emissions reductions. Therefore, enter "0" for:*
>
> - *"Permitted Potential to Emit after the initial action (t/y)",*
> - *"Discount quantity for federal rules in place at the time of initial action (t/y)"*
> - *"Discount quantity for federal rules SINCE the time of initial action (t/y)".*

CARB staff would agree that for most orphan shutdowns, the permit at the time of surrender should reflect all the applicable emission standards. Therefore, any actual emission reductions generated in conformity with the permit should be surplus at the time of permit surrender. However, CARB staff would note several examples discovered in this review where this assumption turned out to be unwarranted, e.g. permits representing "non-compliant dormant emissions units" or "fee-paying units," which contain emission limits that are not reflective of the applicable rule standards. Nevertheless, this by itself should not cause any inaccuracies in the equivalency demonstration provided the surplus value of the reductions is determined at the time the reductions are used as mitigation.

CARB staff has determined that the District's procedure above for assessing actual emissions reductions from orphan shutdown is reasonable and appropriate, with four clarifications. First, in step 4 of the procedure for determining the amount of emission reduction, the word "blanks" should be understood to refer to an absence of data, not actual zeros, i.e., where the record clearly indicates zero emissions or non-operation. Second, orphan reductions should be subject to the surplus-at-time-of-use requirement as required by Rule 2201. Third, when a shutdown involves multiple emissions units, only one consecutive 24-month period (or 12-month period per the District's procedure referenced above) should be used to determine the actual emissions. This stipulation should be observed for determining the amount of creditable reductions from orphan shutdowns because it prevents double counting of emissions that are merely shifting from unit to unit over time (i.e., shifting to a similar

[58] SJVAPCD Offset Equivalency Step-by-Step Instructions, III.C. Bullet point i (C.III.24).

source within a facility or counting emissions that were relied on in an internal offset or netting action). Thus, to use a specific period of emissions inventory for one unit, but not for other units, (and instead using, for example, ½ PE) is inconsistent with this stipulation and inconsistent with how the District would normally bank these reductions were they to go through a formal banking process. Fourth, related to the previous point, the District should not credit emission reductions related to older cancelled permits that could not legally operate or emit at the claimed levels within the five-year look-back period to determine the actual emissions.

CARB staff reviewed a random sample of 11 orphan shutdowns used as mitigation in the 2018 tracking period (Table 14).[59] CARB staff determined a lower value for the reductions than the District had for most of the orphan shutdowns. The differences between CARB's determination and the District's determination appear to result mainly from (1) the District not following the procedure in Steps 1 – 4 noted above, or (2) the District not appropriately discounting the emission reductions to reflect their surplus value.

In orphan reduction 2011-S-9990046-4884, the District did not use the available emission inventory record, the compliance record, correspondence from the operator, or the PE value as indicated on the permit to determine the amount of creditable emission reductions. This shutdown consisted of six petroleum storage tanks and one wastewater storage tank. The District received a letter from the operator requesting cancellation of the permits on November 29, 2010. In the letter, the operator noted the tanks had not operated since summer of 2001. The District's June 29, 2010 inspection report also stated the facility had been out of service since 2001. In June of 2011, the facility submitted a 2010 emission inventory report indicating no throughput for any of the equipment in 2010.

The District claimed 525.8 tons per year of VOC creditable reductions for the surplus-at-time-of-use equivalency in 2011 as indicated by the equivalency database entries showing ini_r_voc and aer_voc = 528.8 tons per year. As of the 2018 equivalency report, 320.1 tons per year VOC had been used in the equivalency demonstrations since 2011 (used_voc) with 205.7 tons per year remaining (r_voc).

CARB staff found that the record demonstrated that actual emissions were zero for this facility since summer of 2001. Following the District's rules for crediting reductions from deleted facilities, the amount of creditable VOC reductions available from the shutdown should have been 0 tons per year. If one allows that the District system tracked these zeros as "blanks" or missing data, then ½ PE would be used. The facility-wide Title V permit S-46-0-2 renewed for this facility in 2009 had a facility-wide cap on

[59] All orphan reductions can be identified in the tracking system and annual reports by the "999----" in their tracking number. The tracking number also reveals the facility identification number associated with the permits and when the District claimed the emission reductions for the tracking system. For example, orphan reduction 2011-S-9990046-4884-1 was from the shutdown of facility S-46, and the District claimed those reductions for the equivalency demonstration in 2011.

VOC emissions of 50 tons per year. Using the District rule that would credit ½ PE for a shutdown facility in the absence of any emission inventory data from the previous five years. At most, the District could claim 25 tons per year of VOC for use in the equivalency demonstration. CARB staff believes the permissible creditable reductions for the shutdown of this facility in 2011 should be 0 tons per year VOC; however, in no case should the amount of creditable reductions be greater than 25 tons per year VOC. The District acknowledged and indicated they would address this issue.

The results from CARB staff's review of the sample of 11 emission reductions from orphan shutdowns used in whole or in part in the 2018 Equivalency Report is presented in Table 14. For each of these shutdowns, CARB staff calculated the amount of orphan actual emission reductions (AER) that could be claimed or used and compared to the amount of credit taken in the District Track_Master and Track_Allocate databases. CARB's results were consistently lower than District's recorded values. These results may or may not be representative of other orphan shutdowns, because each orphan shutdown presents a unique set of circumstances that determines the amount of credit that can be claimed. Detailed explanations and reference documents for all the orphan shutdowns indicated in Table 14 will be included on the San Joaquin Valley ERC Program Review Public Documents web page.

**Table 14. Orphan Credit Comparison between CARB and District Staff for Mitigations Used in the 2018 Report[60]**

| Track Number | NOx (tons per year) District Database | NOx (tons per year) CARB Calculated | VOC (tons per year) District Database | VOC (tons per year) CARB Calculated |
|---|---|---|---|---|
| 2011-S-9990046-4884 | - | - | 525.8 | 0 |
| 2013-C-9990512-5391 | 0.59 | 0.28 | 7.14 | 3.14 |
| 2013-S-9990204-5386 | 2.63 | 0.83 | 0.17 | 0.05 |
| 2010-C-9990263-4278 | 1.0 | 0.3 | 0 | 0 |
| 2010-C-9990583-4282 | 1.2 | 0.04 or 0.09 | 1.3 | 0.08 |
| 2004-S-9990252-1439 | 0.6 | 0.07 or 0.21 | 0.11 | 0.003 or 0.11 |
| 2015-N-9990290-6076 | 0.75 | 0.70 | 0.15 | 0.15 |
| 2015-S-9990494-6077 | 0.63 | * | 0.14 | * |
| 2017-C-9990646-6593 | 9.74 | 1.36 | 2.29 | 1.28 |
| 2018-C-9990445-6878 | 1.93 | 0 | 0.41 | 0 |
| 2018-C-9990547-6880 | 4.03 | 0 | 0.37 | 0 |

*CARB staff did not have the information to verify the District's value.

[60] The District values in the table below are found in Track_Master under one or more fields aer_pollutant ini-r_pollutant, and used_pollutant.

## V. Part 4: Application of Offset Requirements to Permitting

The District's ERC system works as part of a larger NSR program to accomplish the air quality goals in the San Joaquin Valley. ERCs are the currency of offsets, and offsets are a NSR requirement. In most cases, BACT is triggered and evaluated prior to offsets being required. As a result, BACT has a direct relation to whether offsets are triggered and how many are required as part of NSR. Therefore, the final portion of the review focused on how the District calculated and used offsets in the permitting process.

Based on the limited analysis we have conducted, we found the District generally appears to apply its NSR program consistent with its rules and policies. In addition, we found no difference in the application of the District's NSR program between ATCs selected from the community list, and those selected at random.

CARB staff selected 30 ATC projects for this portion of the review. Most of the projects were drawn from a list generated by District staff of approximately 7,200 ATC projects issued by the District from 2016 to 2018. A few projects outside this window were chosen when staff could not locate a project within the 2016 - 2018 window that met the other selection criteria. Half (15 of the ATCs) were selected from random facilities, and the other half (15 of the ATCs) were selected from a list of facilities raised by community groups: Rio Bravo Fresno, Vitro, San Fe Petroleum Terminal, MB Technology, Chevron USA Inc, Aera Energy LLC, Kern Oil and Refining, Alon Bakersfield Refining, and Gallo Glass Company. It should be noted that for the 15 facilities from the list, there were hundreds of individual ATCs from which one was selected at random, from each facility.

CARB selected projects based on several criteria. The main criterion was that the projects had to illustrate some facet of the offsetting requirements, offset exemptions, or calculation methods that feed offset determinations in District Rule 2201. Other aspects of the projects, e.g., BACT, risk assessments, application of prohibitory rules, were also reviewed, however, as they were integral to the ATC project approval. Table 15 lists the projects selected for analysis:

**Table 15. Authority-to-Construct Applications Selected for Review**

| Project ID | Project ID | Project ID | Project ID |
|---|---|---|---|
| S-1171639^ | S-1182997^ | S-1182363 | N-1153167 |
| S-1170151^ | S-1173785^ | S-1150871 | N-1172193 |
| S-1160023^ | C-1172937^ | S-1153552 | N-1162806 |
| S-1173694^ | N-1182628^ | S-1153263 | C-1141302 |
| S-1153809^ | C-1182872^ | N-1162235 | C-1181525 |
| S-1183520^ | C-1051325^ | N-1152244 | N-115001 |
| S-1182998^ | C-1181006^ | N-1153643 | |
| S-1163220^ | S-1183515 | N-1183369 | |

^ Project selected at random from one of 9 facilities requested by community stakeholders.

Consistent with CARB staff's evaluation of ERCs in Part 2 of this report, CARB staff's analysis identified transparency and record gaps as an issue. In a majority (21 of 30) of projects reviewed, the evaluation did not provide enough information to replicate or verify the information used in the District evaluation or provided in the facility application, or did not clearly document calculations. In some cases, citations were not provided for assumptions or the evaluation lacked explanation for determinations. The following ATCs were impacted by lack of information: S-1150871, S-1153263, S-1153552, S-1153809, S-1160023, S-1163220, S-1170151, S-1171639, S-1173694, S-1173785, S-1182363, S-1182997, S-1182998, S-1183515, S-1183520, N-1152244, N-1183369, C-1172937, C-1181006, C-1181525, and C-1182872.

Examples of transparency issues found include:

- S-1183520: The engineering evaluation did not include emission factors or emission calculations used to determine the potential to emit. There was no explanation for the ranking of control technologies in the BACT analysis. The PE and BE calculations were not clear, which affects the quantity of offsets required.
- S-1173694: There were no emission calculations provided, so it was not possible to verify if the District's conclusion that there would be no change in emissions. This affects applicability of BACT, Offsets, and public notice.
- S-1153552: The project was for a relaxation in monitoring requirements, but was classified as a Title V minor modification without a justification in the evaluation. Calculation issues in the PE1 and PE2 tables make the values difficult to follow.

Finally, CARB staff conducted a cursory review of the SJVAPCD and other district's offset thresholds, BACT trigger levels, BACT cost-effectiveness thresholds, and BACT cost-effectiveness assumptions. There are clear differences between the District's BACT trigger and threshold levels compared to other districts. There are also clear differences in these factors among all the districts. While all air district NSR programs have the same basic structure, they vary in their detail. As a result, staff's review of offset thresholds, BACT trigger levels, BACT cost-effectiveness thresholds, and BACT cost-effectiveness assumptions was not sufficient to make specific conclusions about the overall stringency of the District's NSR program. Such an assessment of the district's NSR program is beyond the scope this report.

California air quality policy and management is increasingly focused on addressing community scale impacts along with the long-standing focus on regional attainment of air quality standards governed by both the Clean Air Act and State law. As a result, there is a growing need to understand how existing NSR programs address both regional and community scale needs. The review necessary to develop a sufficient understanding of NSR programs and how they are applied must be broader than an evaluation of a single district's program. As noted NSR programs can vary in complex and nuanced ways. Understanding how they work and what the opportunities are to optimize the systems to ensure they meet current and future needs will require the focused efforts of staff from multiple air districts as well as CARB staff. CARB staff proposes to begin a discussion with the air districts as well as stakeholders concerning the approach for conducting such a review.

## VI. Summary and Recommendations for Future Action

The current SJVAPCD ERC bank contains nearly 11 million pounds of NOx ERCs when valued at time-of-issuance. While the bank is large, 80% of the ERCs it contains were issued more than 20 years ago. As the District's programs have become more stringent, the time-of-use value of these ERCs has declined. The District estimated in 2016 that these ERCs, when valued using time-of-use assumptions, are worth about 18% of the time-of-issuance value. This decline has no immediate impact on the holders of the ERCs, because the value of these ERCs under the District's NSR program is based on time-of-issuance. However, this decline is the reason why EPA requires the equivalency determination – to ensure that the difference between time-of-issuance and time-of-use ERC value is accounted for through sufficient offsets generated by the overall increased stringency of the District's program relative to federal requirements.

The equivalency demonstration was designed to allow the District to take credit for other reductions that are generated through their NSR program, such as the application of NSR to non-major sources, and other areas where the District's program is more stringent than federal requirements. However, when the District was reclassified to extreme non-attainment, the major source emission thresholds were reduced, which substantially reduced the advantage between the District's and federal NSR requirements. For the past decade, the District has heavily relied on orphan shutdowns and electrification projects to demonstrate equivalency. It should be noted that these projects are not related to the stringency of the District's NSR rules.

This review identified three groups of findings which, when viewed together, indicate that the District should strengthen its ERC system, to ensure the program will result in no net increase emissions across the basin, while also providing the ERCs industry needs in the San Joaquin Valley. In reviewing ERC banking actions, ATC evaluations, and the District's equivalency database, staff identified general findings in three areas:

### A. Transparency and Rigor of Analysis

- In many of the ERC and ATC projects reviewed, the evaluations lacked supporting documentation that is necessary to replicate, verify or fully review the District's actions. ERC banking actions were missing information such as emissions inventory submittals, choice of baseline period, Continuous Emissions Monitoring data, source test data, and other information. ATCs in some cases were missing citations for assumptions, and some evaluations lacked explanation for determinations.
- The District's equivalency system database is lacking technical documentation, and is not self-contained, meaning that many calculations are conducted external to the database system, performed by input from or output to spreadsheet files for additional analysis. As a result, the calculations are not fully trackable within the

database system. Staff's analysis identified orphan records in the system and calculation discrepancies in the District's offset requirement equivalency demonstration (i.e., Test 1), caused in part by issues in data entry and data processing procedures before data is entered into the database. Overall, these issues highlight areas for improvement, both in District's staff's analysis, and in the database environment where staff perform calculations and engineering analyses. After the bump-up to extreme non-attainment in 2010, the number of projects has increased, creating a quality assurance challenge in an already complex system.

- Staff's analysis identified several calculation issues relating to orphan shutdowns and electrification projects affecting the surplus-at-time-of-use equivalency demonstration (i.e., Test 2). Electrification projects and orphan shutdowns both appear to be overestimated. In particular, the emission reductions from electrification projects appear overestimated by at least 35 percent. These issues need to be addressed going forward to provide confidence in the surplus-at-time-of-use equivalency demonstration to be submitted in 2020.

B. Rule Implementation

In the second set of findings, staff identified rule implementation issues:

- ERC Timeliness

In 15 of the 52 ERC projects reviewed, the District granted ERCs, generated by facility shutdowns, in which emissions ceased more than 180 days before submission of the ERC application. The District followed its long-standing policy defining shutdown as the surrender of the operating permit, when deciding to grant these ERCs. However, the District's policy conflicts with its Rule, which requires the application to be submitted no later than 180 days after the emission reductions occurred. The District should follow its Rule as written and make adjustments so that both the policy and rule are consistent.

- ERC Surplus Reductions

In four of the 52 ERC projects reviewed, the District granted ERCs even though they appeared to not be surplus of every federal, State, or district law, rule, order, permit, or regulation. This increased the value of the ERC to the applicant, and decreased the value of the ERC in the equivalency demonstration when the ERCs are used. Over time these types of decisions may put the District's offset equivalency demonstration at risk.

C. Offset Equivalency

In the third set of findings, staff identified several issues in the District's equivalency demonstration.

- ERC Electrification Project Eligibility and Calculations

The District relies on electrification projects, generated through the Agricultural Internal Combustion Engine (AG-ICE) incentive program, to demonstrate NOx equivalency with federal requirements. In calculating and claiming credit for these projects, the District used an incorrect load factor, resulting in a significant overvaluing of reductions in the equivalency demonstration. In addition, these reductions were not documented to have resulted from a permitting action, were not documented to be permanently enforceable, and potentially half of the credited projects appeared to be funded in part through the Carl Moyer program. These issues affect the magnitude and eligibility of electrification projects that are the primary basis for NOx equivalency over the past ten years. The District should address these issues in its 2020 Equivalency Demonstration.

Recommendations for Future Action

The issues identified in this report are complex, and impact a wide array of stakeholders in the San Joaquin Valley including residents of the Valley, industries that rely on offsets and ERCs in order to expand or build new business, environmental organizations who advocate for cleaner air, and community groups representing those living near stationary and mobile sources who are impacted the most by emissions at the local level.

As a result of the findings highlighted in this report, CARB staff recommends that the District take specific action to address the following overarching findings as detailed in this evaluation.

- Revise the program to make it more transparent to the public and industry and more rigorous.
- Upgrade the District's Implementation procedures and policies.
- Review and revise assumptions in the equivalency demonstration as identified.

# Exhibit R. San Joaquin Valley Air Pollution Control District, Federal Offset Equivalency, District Advisory (2022)

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

# District Advisory

## Federal Offset Equivalency

April 4, 2022

Under District Rule 2201, new facilities and modifications to existing facilities that result in increases in permitted emissions above specified levels are required to provide offsets as mitigation as a part of the requirements to obtain an "Authority to Construct" permit. Emission Reduction Credits (ERCs) are the currency of offsets. As allowed by the federal Clean Air Act, the District's ERC program has historically differed from a direct implementation of the federal offsetting requirements. EPA approved the District's programmatic approach in 2001 as the District's local program was at least as stringent as the federal program, which is implemented at the individual project level. As included in the District's EPA-approved rule, the District is required to demonstrate ongoing equivalency with the federal offsetting requirements on a programmatic level, and, if the system is unable to demonstrate equivalency with federal requirements, immediate and specified remedies are required to be enacted to ensure federal offsetting obligations are met.

The 2020-21 Annual Offset Equivalency Report highlighted the possibility that the current surplus-value remedy in District Rule 2201 will not be sufficient to ensure the District will be able to remain equivalent with federal offsetting requirements. It is imperative that the District operates an offsetting program that ensures that federal offsetting requirements can be met on an ongoing basis. Consistent with the District's efforts to evaluate the offsetting program and ensure that all state and federal requirements are met, the District's Governing Board took action on February 17, 2022, to require that all new major sources or federal major modifications triggering offsets for NOx be required to provide ERCs for the full federal offset quantity, and that those credits be surplus at time of ATC issuance. As a result of this action, the District is no longer operating a federal offset equivalency system for NOx, and all new major sources or federal major modifications will be required to comply with the federal offset requirements of 40 CFR 51.165 and part D of Title I of the Clean Air Act. This action builds on previous actions that ended the federal offset equivalency system for VOC in late 2020. The District's Board also directed staff to begin a public process to amend Rule 2201 (New Source Review) to formalize these changes and ensure the applicability and offset requirements within Rule 2201 comply with the federal new source review requirements.

Therefore, **EFFECTIVE FEBRUARY 17, 2022**, pursuant to Sections 7.4.1.1 and 7.4.2.1 of District Rule 2201:

- **For NOx and VOC:** All ATCs issued for new major sources or federal major modifications triggering offsets for NOx or VOC are required to provide ERCs that are surplus at time of ATC issuance for the full federal offset quantity as calculated in 40 CFR 51.165(a)(3)(ii)(J).
- **For PM10, PM2.5, and SOx**: No change to the offset quantity and ERC surplus value requirements at this time.

**Questions and Assistance**

If you have any questions regarding this advisory, please contact the District's Small Business Assistance:

**Modesto: 209-557-6446 Fresno: 559-230-5888 Bakersfield: 661-392-5665**


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SBA 209-557-6446
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(661) 392-5500 ♦ FAX (661) 392-5585

# Exhibit S. CalEPA Kern Energy August 2024 and June 2026 Activity Logs

# Kern Oil & Refining Inc. (Kern Energy) Update on Environmental Compliance

August 2024

## Background

Kern Oil & Refining Inc. (Kern Energy) is located at 7724 East Panama Lane, Bakersfield, CA 93307. Kern Energy is a refinery that produces gasoline and diesel fuels. The facility has been in operation since 1934 and was originally known as El Tejon Oil and Refining Company. Kern Energy primarily receives raw material via pipeline but can also receive it by truck and has the capability to process 25,000 barrels of crude per day. In addition to processing crude oil, Kern Energy refines vegetable oil and tallow into biodiesel.

## Is the facility subject to environmental requirements?

Kern Energy is subject to federal, state, and local requirements related to air emissions, water quality, and hazardous materials and waste.

## Who is involved in this matter?

Multiple environmental agencies at the federal, state, and local level are responsible for regulating Kern Energy and have been engaged in inspection and enforcement activities, including:

- San Joaquin Valley Air Pollution Control District (San Joaquin Valley APCD)
- Kern County Certified Unified Program Agency (CUPA)
- California Air Resources Board (CARB)
- State Water Resources Control Board (SWRCB)
- Central Valley Regional Water Quality Control Board (RWQCB)
- California Department of Toxic Substances Control (DTSC)
- California Environmental Protection Agency (CalEPA)
- United States Environmental Protection Agency (US EPA)

## San Joaquin Valley APCD Actions

The San Joaquin Valley APCD is a public health agency whose mission is to improve the health and quality of life for all Valley residents through efficient, effective, and entrepreneurial air quality management strategies, which include the adoption and enforcement of rules intended to control sources of air pollution. In addition to public complaint investigations and joint inspections with other agencies, District enforcement staff perform field inspections at Kern Energy to ensure the facility's strict adherence to applicable District Rules, as well as state and federal regulations, which include District Rules 2520, 4311, 4455, 4460, 4623, and 4702, and 40 CFR Part 60 requirements.

The District takes enforcement action whenever violations are found. Following an enforcement action, the District works with the facility to expedite their return to compliance, which is often accomplished on the same day the violation was discovered.

From January 2021 through July 2023, District staff conducted over fifty inspections and other field operations at Kern Energy, including a joint inspection of the facility with USEPA in April 2023.

Additionally, Kern Energy is located in the Assembly Bill 617 (AB 617) community of Arvin/Lamont. AB 617 requires the California Air Resources Board (CARB) to select communities who are being disproportionately impacted by pollution and to work with air districts to develop and implement additional emissions reporting, monitoring, emissions reduction programs, and measures in an effort to reduce localized air pollution exposure in these communities, and in 2021, Arvin/Lamont was selected for investment of additional resources under AB 617. After extensive coordination with community members over the following months, the District's Governing Board unanimously voted to adopt the Arvin/Lamont AB 617 Community Emissions Reduction Program (CERP), which includes strategies for reducing air pollution impacts from sources of pollution that are of particular concern to community members. A detailed summary of enforcement activities for all of the Arvin/Lamont community, including those for Kern Energy, from October 2018 to September 2021, can be found in the CERP, Appendix E, which can be accessed on the District's website through the following link: https://community.valleyair.org/media/bufpshwq/appendix-e_enforcement-plan.pdf

Ongoing enforcement updates are provided to the community in Appendix B of the Annual Report on the community specific webpage. Links to the webpage and reports are both available in English and Spanish are found here: http://community.valleyair.org/selected-communities/arvin-lamont/reports-and-document-archive/

The San Joaquin Valley APCD's compliance activities at Kern Energy dating back to 2018 are summarized below:

- In 2023: 23 inspections, 16 enforcement actions taken, and 8 complaints investigated.
    - Failure to perform annual visual seal gap inspection of a tank, monitor and record stack concentrations, calibrate Flare Continuous Emissions Monitoring System (CEMS), failure to comply with emission limits, maintain infrastructure, prevent leaks, ensure functional vapor recovery systems, repair a liquid leak, operate the flare with pilot flame present at all times, remain below maximum start-up and shut-down time, and ensure lines in Reformer are close ended.
- In 2022: 27 inspections, 16 enforcement actions taken, and 2 complaints investigated.
    - Failure to submit an Emission Control Plan for Rule 4320, failure to comply with emission limits, prevent leaks, ensure all lines are close-ended and drain pit is equipped with solid covers, maintain infrastructure, ensure a functional vapor recovery system, and equip tank with a PV vent.
- In 2021: 19 inspections, 17 enforcement actions taken, and 3 complaints investigated.
    - Complaints: Flares and odors were reported. No odors were identified during investigation.
    - NOVs: Issued for failure to comply with emission standards, comply with permit requirements, control vapors, submit unplanned flaring events, ensure a functional vapor recovery system, test engine after restart, prevent leaks, and conduct a source test.
- In 2020: 16 inspections, 21 enforcement actions taken, and 8 complaints investigated.
    - Complaints: Fires, strong odors, black smoke, and flares were reported. Fires were referred to OSHA, and NOVs were issued for VOC leaks and a breakdown. No violations were identified when flares were reported.
    - NOVs: Issued for failure to conduct source tests, prevent excess emissions, prevent, and repair leaks, comply with permit requirements, submit deviations, control vapors, and ensure a functional vapor recovery system.
- In 2019: 8 inspections, 16 enforcement actions taken, and no complaints were received.
    - NOVs: Issued for failure to monitor emissions, comply with permit requirements, prevent, and repair leaks, comply with emission limits, failure to provide records, and equip exhaust controls.
- In 2018: 9 inspections, 8 enforcement actions taken, and 2 complaints investigated.
    - Complaints: Excess sulfur emissions due to upset in sulfur recovery unit. NOV issued.
    - NOVs: Issued for failure to obtain permits, monitor emissions, prevent leaks, and comply with emission limits.

## Kern County CUPA Actions

The Kern County Environmental Health Services Department operates as the Certified Unified Program Agency (CUPA) for Kern County. The CUPA ensures compliance with requirements related to hazardous materials, hazardous waste, and storage tanks.

- Kern County CUPA conducted an inspection of Kern Energy on February 15, 2023. The inspection involved: Hazardous Materials Business Plan (HMBP), Aboveground Petroleum Storage Act (APSA), Resource Conservation and Recovery Act (RCRA): Hazardous Waste Excluded or Exempted Material Recycler, and the California Accidental Release Prevention (CalARP) refinery program.
    - No violations were identified at the time of the inspection.
- Kern County CUPA conducted an inspection of Kern Energy on February 21, 2024. The inspection involved the HMBP, APSA, RCRA: Hazardous Waste, Excluded or Exempted Material Recycler, and the CalARP refinery program.
    - 2 – Class II Violations to the HMBP program were identified due to an incomplete hazardous material inventory plan and site map not meeting minimum requirements. Corrective Actions for the HMBP violations were completed for the Inventory on April 15, 2024, and for the site map on March 11, 2024.
    - 2 – Class II Violations to the APSA program were identified due to failure to amend the SPCC plan and failure to provide and maintain secondary containment. The facility ordered secondary containment pallets and was awaiting their delivery

(May-June) to update the SPCC plan. They have since acquired secondary containments for qualifying materials and amended their SPCC plan with updated containments and quantities and have resolved the violation.
    - No violations of the RCRA: Hazardous Waste, Excluded or Exempted Material Recycler program were identified at the time of the inspection.
    - 1 – Class II Violation to the CalARP program was identified due to emergency operations procedures do not meet the minimum requirements for Program 4. The facility is currently working through the revisions of their SOP's and expect this to be completed December 31, 2024.

## CARB Actions

CARB is responsible for protecting the public from the harmful effects of air pollution and developing and enforcing programs and actions to fight climate change. CARB enforcement programs protect public health by ensuring statewide regulatory requirements are met and local community concerns are addressed. CARB programs target oil and gas sources through enforcement of fuel standard and methane leak regulations. CARB has no recent compliance history for Kern Oil and Refining.

## State and Regional Water Board Actions

Kern Energy (Kern) is subject to Cleanup and Abatement Order 95-052 (Order) requirements. The order was issued in 1995 after inspections identified spill and leaks of petroleum products from aboveground tanks, pumps, valves, and piping in the tank farms.

- The Site is currently under active remediation by soil vapor extraction and regular bailing of groundwater monitoring wells to remove free product where it is present. Site groundwater and soil vapor are on a semi-annual monitoring and reporting schedule.
- In January 2022, Regional Water Board staff conducted a detailed review of the case history and issued a Case Status Review dated January 14, 2022, which identified several failures to comply with the requirements and due dates of the Order. Since the case status review was issued, Kern submitted a Comprehensive Assessment Workplan on July 12, 2022 (Workplan), designed to bring Kern into compliance with the Order and close data gaps to develop a comprehensive remedial approach. The Workplan was approved by a Water Board staff letter dated December 5, 2022. Kern Energy began implementing the Workplan during the first quarter of 2023 and the final work plan implementation report was submitted on September 26, 2023. Kern Energy indicated in the report they are preparing a corrective action plan based on the results of the comprehensive site assessment. Water Board staff are currently reviewing the workplan implementation report and recent groundwater and soil vapor extraction monitoring reports and preparing a formal response.
- Kern Energy is conducting a parallel site investigation for Per- and Polyfluoroalkyl Substances (PFAS). Kern Energy completed a site assessment in 2022 and 2023 and submitted a June 22, 2023, report which identified evidence of past releases of aqueous film forming foam (AFFF) which contains PFAS and is used for fire suppression and indicated the presence of PFAS in several areas of site in soil, stormwater, and groundwater. A workplan for additional site assessment was submitted on March 22, 2024.

## DTSC Actions

The California Department of Toxic Substances Control (DTSC) regulates the generation, handling, transportation, storage, treatment, and disposal of hazardous wastes. The petroleum refining industry is one of the largest generators of hazardous waste in California. These wastes are shipped under hazardous waste manifest to offsite treatment, storage, or disposal facilities. Many different types of hazardous wastes are generated by petroleum refineries, including inorganic solid wastes, spent catalysts, aqueous waste with organics, and aqueous waste with metals.

- DTSC conducted an inspection of Kern Energy in March of 2021. Three violations were observed during inspection and a Summary of Violations was issued. The violations are as follows:
    - Kern Energy failed to properly label one container of universal waste-lamps.
    - Kern Energy failed to properly label one container of universal waste- electronic devices.
    - Kern Energy failed to indicate the particular hazardous property on three containers storing hazardous wastes.
- The facility submitted a letter in response to the Summary of Violations on April 26th, 2021, and included photographic evidence that the violations had been corrected.

## CalEPA Actions

CalEPA is the parent agency to six boards, departments, and offices charged with protecting public health and the environment, including DTSC, CARB, and the Water Boards. CalEPA has not exercised independent enforcement authority over activities at Kern Energy but helps to ensure enforcement and compliance activities are consistent, effective, and coordinated.

## US EPA Actions

USEPA Region 9 (Pacific Southwest Region) provides regulatory oversight over states, tribes, and territories. USEPA works with state and local agencies to ensure private and public facilities maintain compliance under environmental statutes, including the Clean Air Act (CAA). USEPA has conducted inspections of Kern Energy under the CAA and entered a settlement with the refinery as described below.

- USEPA conducted an inspection of Kern Energy in April 2023 under the CAA. The inspection report was finalized July 13, 2023, and EPA identified the following concerns:
    - EPA observed that elevated background around the Transmix Unit, which was caused by maintenance operations, provoked concerns about excess emissions.
    - EPA observed that many of the rail car hose connections were leaking in the same or similar areas.
- On March 19, 2020, the U.S. Magistrate Judge signed and entered an EPA/DOJ/SJVAPCD joint settlement with the company to resolve alleged violations at the petroleum refinery. The company paid a $500,000 penalty to address failures to comply with flare emissions monitoring and leak inspection reporting under the Clean Air Act (CAA) and toxic chemical release reporting under the Emergency Planning and Community Right-to-Know Act. Additionally, the company spent $200,000 on supplemental environmental projects that included an infrared camera used to detect vapor leaks and emergency responder equipment for the Kern County Fire and Public Health Services Departments.
- USEPA conducted an inspection of Kern Oil Refinery on April 17, 2014, under the CAA.

USEPA maintains the Enforcement and Compliance History Online (ECHO) database that focuses on compliance- and enforcement-related information for EPA-regulated facilities. ECHO includes permit data, inspection/compliance evaluation dates and findings, violations of environmental regulations, enforcement actions, and penalties assessed for federally regulated sources of pollution, including Kern Energy. The ECHO page for Kern Energy can be accessed through the following link: https://echo.epa.gov/detailed-facility-report?fid=110000481611&ej_type=sup&ej_compare=US

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# Kern Oil & Refining Inc. (Kern Energy) Update on Environmental Compliance

June 2026

## Background

Kern Oil & Refining Inc. (Kern Energy) is located at 7724 East Panama Lane, Bakersfield, CA 93307. Kern Energy is a refinery that produces gasoline and diesel fuels. The facility has been in operation since 1934 and was originally known as El Tejon Oil and Refining Company. Kern Energy primarily receives raw material via pipeline but can also receive it by truck and has the capability to process 25,000 barrels of crude per day. In addition to processing crude oil, Kern Energy refines vegetable oil and tallow into biodiesel.

## Is the facility subject to environmental requirements?

Kern Energy is subject to federal, state, and local requirements related to air emissions, water quality, and hazardous materials and waste.

## Who is involved in this matter?

Multiple environmental agencies at the federal, state, and local level are responsible for regulating Kern Energy and have been engaged in inspection and enforcement activities, including:

- San Joaquin Valley Air Pollution Control District (San Joaquin Valley APCD)
- Kern County Certified Unified Program Agency (CUPA)
- California Air Resources Board (CARB)
- State Water Resources Control Board (SWRCB)
- Central Valley Regional Water Quality Control Board (RWQCB)
- California Department of Toxic Substances Control (DTSC)
- California Environmental Protection Agency (CalEPA)
- United States Environmental Protection Agency (US EPA)

## San Joaquin Valley APCD Actions

The San Joaquin Valley APCD is a public health agency whose mission is to improve the health and quality of life for all Valley residents through efficient, effective, and entrepreneurial air quality management strategies, which include the adoption and enforcement of rules intended to control sources of air pollution. In addition to public complaint investigations and joint inspections with other agencies, District enforcement staff perform field inspections at Kern Energy to ensure the facility's strict adherence to applicable District Rules, as well as state and federal regulations, which include District Rules 2520, 4306, 4311, 4320, 4455, 4460, 4623, and 4702, and 40 CFR Part 60 requirements.

The District takes enforcement action whenever violations are found. Following an enforcement action, the District works with the facility to expedite their return to compliance, which is often accomplished on the same day the violation was discovered.

From August 2023 through March 2026, District staff conducted over sixty inspections and other field operations at Kern Energy.

Additionally, Kern Energy is located in the Assembly Bill 617 (AB 617) community of Arvin/Lamont. AB 617 requires the California Air Resources Board (CARB) to select communities who are being disproportionately impacted by pollution and to work with air districts to develop and implement additional emissions reporting, monitoring, emissions reduction programs, and measures in an effort to reduce localized air pollution exposure in these communities, and in 2021, Arvin/Lamont was selected for investment of additional resources under AB 617. After extensive coordination with community members over the following months, the District's Governing Board unanimously voted to adopt the Arvin/Lamont AB 617 Community Emissions Reduction Program (CERP), which includes strategies for reducing air pollution impacts from sources of pollution that are of particular concern to community members. A detailed summary of enforcement activities for all of the Arvin/Lamont community, including those for Kern Energy, from October 2018 to September 2021, can be found in the CERP, Appendix E, which can be accessed on the District's website through the following link: https://community.valleyair.org/media/bufpshwq/appendix-e_enforcement-plan.pdf

Ongoing enforcement updates are provided to the community in Appendix B of the Annual Report on the community specific webpage. Links to the webpage and reports are both available in English and Spanish are found here: http://community.valleyair.org/selected-communities/arvin-lamont/reports-and-document-archive/

The San Joaquin Valley APCD's compliance activities at Kern Energy dating back to 2018 are summarized below:

- In 2025: 6 inspections, 16 enforcement actions taken, and 15 complaints investigated.
    - Failure to maintain vapor recovery system, submit deviation reports, comply with H2S limit, operate flare and fuel gas CEMS, and remain below start-up and shut-down time.
- In 2024: 28 inspections, 49 enforcement actions taken, and 30 complaints investigated.
    - Failure to maintain tanks and loading rack in leak free status, comply with H2S limit, maintain tank seal, prevent leaks, remain below maximum start-up and shut-down time, maintain water pit cover, comply with SOx emissions limit, comply with NOx and CO limits, maintain vapor recovery system and CEMS, maintain components in leak free status, and comply with annual heat input limit
- In 2023: 43 inspections, 32 enforcement actions taken, and 8 complaints investigated.
    - Failure to perform annual visual seal gap inspection of a tank, monitor and record stack concentrations, calibrate Flare Continuous Emissions Monitoring System (CEMS), failure to comply with emission limits, maintain infrastructure, prevent leaks, ensure functional vapor recovery systems, repair a liquid leak, operate the flare with pilot flame present at all times, remain below maximum start-up and shut-down time, and ensure lines in Reformer are close ended.
- In 2022: 27 inspections, 16 enforcement actions taken, and 2 complaints investigated.
    - Failure to submit an Emission Control Plan for Rule 4320, failure to comply with emission limits, prevent leaks, ensure all lines are close-ended and drain pit is equipped with solid covers, maintain infrastructure, ensure a functional vapor recovery system, and equip tank with a PV vent.
- In 2021: 19 inspections, 17 enforcement actions taken, and 3 complaints investigated.
    - Complaints: Flares and odors were reported. No odors were identified during investigation.
    - NOVs: Issued for failure to comply with emission standards, comply with permit requirements, control vapors, submit unplanned flaring events, ensure a functional vapor recovery system, test engine after restart, prevent leaks, and conduct a source test.
- In 2020: 16 inspections, 21 enforcement actions taken, and 8 complaints investigated.
    - Complaints: Fires, strong odors, black smoke, and flares were reported. Fires were referred to OSHA, and NOVs were issued for VOC leaks and a breakdown. No violations were identified when flares were reported.
    - NOVs: Issued for failure to conduct source tests, prevent excess emissions, prevent, and repair leaks, comply with permit requirements, submit deviations, control vapors, and ensure a functional vapor recovery system.
- In 2019: 8 inspections, 16 enforcement actions taken, and no complaints were received.
    - NOVs: Issued for failure to monitor emissions, comply with permit requirements, prevent, and repair leaks, comply with emission limits, failure to provide records, and equip exhaust controls.
- In 2018: 9 inspections, 8 enforcement actions taken, and 2 complaints investigated.
    - Complaints: Excess sulfur emissions due to upset in sulfur recovery unit. NOV issued.
    - NOVs: Issued for failure to obtain permits, monitor emissions, prevent leaks, and comply with emission limits.

## Kern County CUPA Actions

The Kern County Environmental Health Services Department operates as the Certified Unified Program Agency (CUPA) for Kern County. The CUPA ensures compliance with requirements related to hazardous materials, hazardous waste, and storage tanks.

- Kern County CUPA conducted an inspection of Kern Energy on August 22, 2024. The inspection involved: Hazardous Materials Business Plan (HMBP), Aboveground Petroleum Storage Act (APSA), Resource Conservation and Recovery Act (RCRA): Hazardous Waste Excluded or Exempted Material

Recycler, and the California Accidental Release Prevention (CalARP) refinery program.

- 1 – Class II Violation to the Hazardous Waste program was identified due to improper management of hazardous waste as a container of used oil was observed in the hazardous waste storage area without a lid and not placed in an approved hazardous waste container. Corrective Action for the Hazardous Waste violation was completed on August 22, 2024.
- 1 – Class II Violation to the CalARP program was identified due to the facility failing to update and revalidate the Process Hazard Analysis at least every five years. Corrective Action for the CalARP violation was completed on April 23, 2025.

- Kern County CUPA participated in a Process Hazard Analysis review on September 17, 2024, and September 19, 2024.
- Kern County CUPA conducted an inspection of Kern Energy on March 18, 2025. The inspection involved the California Accidental Release Prevention (CalARP) refinery program.
  - No violations were identified at the time of the inspection.
- Kern County CUPA conducted an inspection of Kern Energy on August 25, 2025. The inspection involved the California Accidental Release Prevention (CalARP) refinery program.
  - No violations were identified at the time of the inspection.
- Kern County CUPA conducted an inspection of Kern Energy on December 1, 2025. The inspection involved the California Accidental Release Prevention (CalARP) refinery program.
  - No violations were identified at the time of the inspection.
- Kern County CUPA conducted an inspection of Kern Energy on March 30, 2026. The inspection involved: Hazardous Materials Business Plan (HMBP), Aboveground Petroleum Storage Act (APSA), Resource Conservation and Recovery Act (RCRA): Hazardous Waste Excluded or Exempted Material Recycler, and the California Accidental Release Prevention (CalARP) refinery program.
  - 1 – Class II Violation to the APSA program was identified due to a secondary containment failure involving an unauthorized release. Corrective Action for the APSA violation is currently in progress.
- Kern County CUPA conducted an inspection of Kern Energy on February 15, 2023. The inspection involved: Hazardous Materials Business Plan (HMBP), Aboveground Petroleum Storage Act (APSA), Resource Conservation and Recovery Act (RCRA): Hazardous Waste Excluded or Exempted Material Recycler, and the California Accidental Release Prevention (CalARP) refinery program.
  - No violations were identified at the time of the inspection.
- Kern County CUPA conducted an inspection of Kern Energy on February 21, 2024. The inspection involved the HMBP, APSA, RCRA: Hazardous Waste, Excluded or Exempted Material Recycler, and the CalARP refinery program.
  - 2 – Class II Violations to the HMBP program were identified due to an incomplete hazardous material inventory plan and site map not meeting minimum requirements. Corrective Actions for the HMBP violations were completed for the Inventory on April 15, 2024, and for the site map on March 11, 2024.
  - 2 – Class II Violations to the APSA program were identified due to failure to amend the SPCC plan and failure to provide and maintain secondary containment. The facility ordered secondary containment pallets and was awaiting their delivery (May-June) to update the SPCC plan. They have since acquired secondary containments for qualifying materials and amended their SPCC plan with updated containments and quantities and have resolved the violation.
  - No violations of the RCRA: Hazardous Waste, Excluded or Exempted Material Recycler program were identified at the time of the inspection.
  - 1 – Class II Violation to the CalARP program was identified due to emergency operations procedures do not meet the minimum requirements for Program 4. The facility is currently working through the revisions of

their SOP's and expect this to be completed December 31, 2024.

## CARB Actions

CARB is responsible for protecting the public from the harmful effects of air pollution and developing and enforcing programs and actions to fight climate change. CARB enforcement programs protect public health by ensuring statewide regulatory requirements are met and local community concerns are addressed. CARB programs target oil and gas sources through enforcement of fuel standard and methane leak regulations. CARB has no recent compliance history for Kern Oil and Refining.

## State and Regional Water Board Actions

Kern Energy is subject to Cleanup and Abatement Order 95-052 (Order) requirements. The Order was issued in 1995 after inspections at their facility identified spills and leaks of petroleum products from aboveground tanks, pumps, valves, and piping in the tank farms.

- The facility is currently under active remediation by soil vapor extraction and regular bailing of groundwater monitoring wells to remove free product where it is present. Facility groundwater and soil vapor are on a semi-annual monitoring and reporting schedule.
- In January 2022, Regional Water Board staff conducted a detailed review of the facility history and issued a Case Status Review letter to Kern Energy dated January 14, 2022, which identified several failures to comply with the requirements and due dates of the Order. Since the Case Status Review letter was issued, Kern Energy submitted a Comprehensive Assessment Workplan on July 12, 2022 (Workplan), designed to bring Kern Energy into compliance with the Order and close data gaps to develop a comprehensive remedial approach. The Workplan was approved by Regional Water Board staff in a letter dated December 27, 2022. Kern Energy began implementing the Workplan during the first quarter of 2023 and the final Workplan implementation report was submitted on September 25, 2023 (Comprehensive Assessment Report). The Comprehensive Assessment Report identified additional source areas and widespread petroleum hydrocarbons in both soil and soil vapor. Regional Water Board staff responded in a letter dated November 20, 2024, that included the need for further plume delineation, for additional monitoring capabilities in several areas of the facility, for a plan to remediate soil and groundwater in newly identified contaminated areas, and for the consideration of additional soil vapor extraction. Kern Energy is implementing Regional Water Board comments in the November 20, 2024 letter.
- Kern Energy is conducting a parallel site investigation for per- and polyfluoroalkyl substances (PFAS). Kern Energy completed a site assessment in 2023 and submitted a June 22, 2023 report. The report identified evidence of past releases of aqueous film forming foam (AFFF) containing PFAS. AFFF was stored at the facility for fire suppression and related PFAS contamination was identified in several areas of the facility in soil, stormwater, and groundwater. A workplan for additional site assessment was submitted by Kern Energy on March 22, 2024 and approved by Regional Water Board staff in a letter dated January 8, 2025.

## DTSC Actions

The California Department of Toxic Substances Control (DTSC) regulates the generation, handling, transportation, storage, treatment, and disposal of hazardous wastes. The petroleum refining industry is one of the largest generators of hazardous waste in California. These wastes are shipped under hazardous waste manifest to offsite treatment, storage, or disposal facilities. Many different types of hazardous wastes are generated by petroleum refineries, including inorganic solid wastes, spent catalysts, aqueous waste with organics, and aqueous waste with metals.

- DTSC conducted an inspection of Kern Energy in March of 2021. Three violations were observed during inspection and a Summary of Violations was issued. The violations are as follows:
    - Kern Energy failed to properly label one container of universal waste-lamps.
    - Kern Energy failed to properly label one container of universal waste- electronic devices.

    - Kern Energy failed to indicate the particular hazardous property on three containers
    - storing hazardous wastes.
- The facility submitted a letter in response to the Summary of Violations on April 26th, 2021, and included photographic evidence that the violations had been corrected.

- DTSC conducted a Compliance Evaluation Inspection (CEI) of Kern Energy on April 7 and 8, 2026. Four violations were observed during the inspection, and a Summary of Violations was issued. The Violations are as follows:
    - #1 Violation class: Minor. Failure to store universal waste and hazardous waste in closed containers.
    - #2 Violation class: Minor. Failure to label containers containing universal waste and hazardous waste.
    - #3 Violation class: Minor. Failure to properly store hazardous waste in a container.
    - #4 Violation class: Minor. Failure to store empty containers with the dates they were emptied.
- The facility submitted a letter in response to the CEI on May 26, 2026, Kern Energy returned to compliance and included the photographic evidence that the violations had been corrected.

## CalEPA Actions

CalEPA is the parent agency to six boards, departments, and offices charged with protecting public health and the environment, including DTSC, CARB, and the Water Boards. The HMBP/CalARP Unit at CalEPA oversees the implementation of the CalARP Program at the state level. CalEPA is focused providing support to CUPA's as well as ensuring enforcement and compliance activities are consistent, effective, and coordinated. The CalEPA HMBP/CalARP unit was not a participating agency of the Environmental Justice Task Force during the Kern Oil & Refining environmental justice initiative, and therefore, has not coordinated nor provided support to Kern County Environmental Health Department regarding this facility as it relates to this initiative.

## US EPA Actions

USEPA Region 9 (Pacific Southwest Region) provides regulatory oversight over states, tribes, and territories. USEPA works with state and local agencies to ensure private and public facilities maintain compliance under environmental statutes, including the Clean Air Act (CAA). USEPA has conducted inspections of Kern Energy under the CAA and entered a settlement with the refinery as described below.

- USEPA conducted an inspection of Kern Energy in April 2023 under the CAA. The inspection report was finalized July 13, 2023, and EPA identified the following concerns:
    - EPA observed that elevated background around the Transmix Unit, which was caused by maintenance operations, provoked concerns about excess emissions.
    - EPA observed that many of the rail car hose connections were leaking in the same or similar areas.
- On March 19, 2020, the U.S. Magistrate Judge signed and entered an EPA/DOJ/SJVAPCD joint settlement with the company to resolve alleged violations at the petroleum refinery. The company paid a $500,000 penalty to address failures to comply with flare emissions monitoring and leak inspection reporting under the Clean Air Act (CAA) and toxic chemical release reporting under the Emergency Planning and Community Right-to-Know Act. Additionally, the company spent $200,000 on supplemental environmental projects that included an infrared camera used to detect vapor leaks and emergency responder equipment for the Kern County Fire and Public Health Services Departments.
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USEPA maintains the Enforcement and Compliance History Online (ECHO) database that focuses on compliance- and enforcement-related information for EPA-regulated facilities. ECHO includes permit data, inspection/compliance evaluation dates and findings, violations of environmental regulations, enforcement actions, and penalties assessed for federally regulated sources of pollution, including Kern Energy. The ECHO page for Kern Energy can be accessed through the following link: https://echo.epa.gov/detailed-facility-report?fid=110000481611&ej_type=sup&ej_compare=US

## For More Information Contact:

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# Exhibit T. 2025-2026 Kern County Grand Jury Report on Kern County Fire Department Office Of Emergency Services Disaster Readiness

# 2025-2026 KERN COUNTY GRAND JURY

## KERN COUNTY FIRE DEPARTMENT
## OFFICE OF EMERGENCY SERVICES
## DISASTER READINESS

**Preparedness is On You**

**Release Date**
**January 27, 2026**


KERN COUNTY
CALIFORNIA
GRAND JURY

# KERN COUNTY FIRE DEPARTMENT
# OFFICE OF EMERGENCY SERVICES
# DISASTER READINESS

## Preparedness is On You



Emergency Preparedness 3-day Backpack, OSHA approved.
(Go Bag with contents such as food and first aid materials displayed)
Photo from IndustrialSafety.com

## SUMMARY:

The primary questions were: Does Kern County (County) and all 11 of its incorporated cities recognize and respond to disabled, non-ambulatory, and elderly residents in emergencies? Can the County notify those residents in a timely and effective way and provide transport in the event of evacuation? The 2025-2026 Kern County Grand Jury (Grand Jury) examined how the County's Emergency Operations Plan (EOP) is implemented and how all areas of the County respond and coordinate with this plan. Particular emphasis is on aid or evacuation assistance for disabled and elderly residents. The EOP is developed in response to local needs and to comply with mandated Federal Emergency Management and California State Emergency Management laws. This all-hazards document provides for the integration and coordination of planning efforts by the County with those of its cities, special districts, and regional State agencies.

The total County population is 907,958, per *World Population Review, 2025*. There are more than 147,000 residents 60 years of age or older, comprising 16% of the total population. According to the National Council on Aging (NCOA), nearly 95% of adults aged 60 and older have at least one chronic condition; nearly 80% have two or more. Health concerns lead to increased need for assistance from local government and non-governmental organizations to meet these chronic needs. There are 47,000 older adults reporting they have one or more disabilities. This fast growing segment of the population includes almost 11,000 over the age of 85. (Area Plan 2024-2028, Message to the Community, Aging and Adult Services)

## PURPOSE OF INQUIRY:

California Penal Code §925, authorizes the Grand Jury to conduct inquiries and investigations into the operations, accounts, and records of County departments. This report is a review of city and county disaster readiness, particularly in relation to elderly or disabled residents.

Under Federal and California State law, all counties and incorporated cities are required to plan for emergency response to disasters. This must include specific plans to address the needs of disabled and/or elderly residents. Some of the primary laws are:

- Stafford Act, November 1988
- Disaster Mitigation Act of 2000
- Title II of the Federal Americans with Disability Act, rev. 2016
- California Emergency Services Act, CESA, Sept. 1970
- California State Government Code §8589.6

The County Office of Emergency Services (OES) is charged with coordinating with county, cities, special districts and regional response to large-area emergencies. The OES is critically important and is factored heavily in this report.

## METHODOLOGY:

During this investigation internet research was conducted. Interviews and a tour were performed at OES. Further onsite interviews were conducted with representatives of the cities of Bakersfield and Shafter along with the Kern County Aging and Adult Services. Then phone interviews were conducted with representatives of the remaining nine incorporated cities. Interviews were held with the Kern County Fire Department, and a safety representative of the Department of Human Services.

## DISCUSSION OF FACTS:

Kern County has significant geological elevation changes, several active earthquake faults, one major river system, and an ancient series of dry lakebeds. Seasonal droughts lead to large, difficult-to-control fires in remote regions. The County's economic bases of large-scale agricultural and oil production, along with heavy truck and rail transport, creates multiple potential ignition points for disasters.

The County is well prepared for large area disasters and emergencies. There have been extensive experiences with fire disasters in the Lake Isabella area, such as the 2016 Erskine fire, the 2024 Borel fire, and a 2024 chemical spill near Shafter.

In September of 2016, the County completed renovation of a dedicated, state-of-the-art Office of Emergency Services (OES) building. The building is self-contained with necessary systems and backups. There are administrative offices and a large conference room holding 51 seated positions, each with a computer, monitor, and phone (Addendum A). During emergencies, personnel from

emergency support services collaborate to provide real-time support to the Incident Commander. This includes specialists from fire, rescue, law enforcement, coroner, and technical support, along with damage assessments, city and support agency liaisons, and public information officers.

Their placement together in a single, large room allows staff responding to a disaster to have easy face-to-face, frequent communication which is critical for rapid, efficient response. The facility can become fully operational within hours of the initial call-out, and once it is operational, staff remain onsite or immediately available. The OES Manager is the lead administrator; however, this person is heavily reliant upon the specialists and on-scene first responders in decision-making. There are periodic practice events, termed "tabletops," where emergency specialists work out response scenarios to create efficient procedures. The OES Manager retired in September 2025 and has yet to be replaced.

The City of Bakersfield is the only city in the County that relies upon its own fire department as the initial first responder to disasters. The Cities of Shafter and Arvin use their own police departments for initial disaster responses. All other incorporated cities have contractual agreements and rely upon the Kern County Fire Department (KCFD). First responders, police or fire, make on-site assessments of potential emergencies. Once an on-scene responder has determined a need for greater services, they forward a request to their Incident Commander, who may decide an emergency declaration is needed. For all 11 cities in the County, the City Manager, in conjunction with first responders, may request activation of the County OES. Upon activation, appropriate agencies, and personnel from all over the County, which may include State and Federal resources, are pulled in to respond and coordinate with the Incident Commander and on-scene first responders. (Addendum B)

California State Government Code §8589.6, also established voluntary guidelines for "local government agencies and community-based organizations to develop a disaster registry program." The County implemented a registry titled ReadyKern, a dedicated emergency alert notification program used to notify residents of disasters or evacuations. To allow efficient disaster management, the County uses software called Genasys Protect®, which, in addition to allowing real-time control of disaster responses, coordinates with ReadyKern in providing warning notices to residents. Also, the Kern County Sheriff's Office is developing a real-time resident geolocator application, allowing deputies to immediately update their commanders.

With an emergency declaration, two of the County social service agencies are activated: The Department of Human Services (DHS) and the Kern County Aging and Adult Services (AAS). The DHS staff are activated to open and coordinate relief centers. The AAS makes efforts to identify and contact people who are listed in their system in need of extra support, such as medical or transportation help. With activation, the OES can dispatch transport assistance within 20 minutes after receiving a request. The AAS also works on pre-planning with their clients, including pre-disaster planning brochures, outreach to Kern communities, and works with In-Home Supportive Services (IHSS). This gives more outreach to elderly and disabled people.

## FINDINGS:

F1. Not all Kern County cities have current disaster plans, leading to an inability to coordinate with the OES.

F2. The County does not have a permanent Manager for the critical Office of Emergency Services. This position relies upon interpersonal communication for the efficient response to emergencies and has been left vacant for months.

F3. The OES has a state-of-the-art facility, and there is no apparent need for further upgrades at this time.

F4. The OES uses tabletop practices for disaster response but does not practice real-time field exercises.

F5. ReadyKern notification and Genasys Protect systems do not have the ability for registrants to note disabilities or the need for special transport when registering. This could lead to delays in evacuation. (Addendums C and D)

F6. There are not sufficient coordinated efforts by the County and cities to inform residents about the need to prepare for a disaster; thus, many residents are unaware of the need to have disaster plans.

F7. The OES has 10 emergency trailers: Three are Americans with Disability Act (ADA) equipped, one is a specialized ADA shower trailer. The remaining six are shelter supply trailers. This appears to be sufficient to meet the current disaster needs of the County. (Addendum E)

F8. The Kern County Sheriff's Office is implementing a new software program that allows deputies to use drop-down menus on cell phones to geolocate all residences and notify their command centers that contact has or has not been made. This system does not coordinate with Genasys or the OES.

F9. The County Emergency Operations Plan is specific in stating, "All Kern County residents share responsibility for minimizing the impacts of disasters on the community…." Therefore, the expectations are that residents should be responsible for their own welfare.

F10. County residents have been asked to have Go Bags ready should they need to evacuate. Currently, it is estimated that less than 10% of residents have a Go Bag prepared.

F11. The Federal Emergency Management Agency (FEMA) has historically been a major funder and driver of disaster preparedness. It is unknown how federal administration policies will affect FEMA's programs and their impact on OES.

F12. The County has plans for the notification, transport to, and placement in shelters for the elderly, handicapped, and disabled residents. The County does not have a reliable program for residents to pre-notify the OES of special needs in the event of a disaster.

## RECOMMENDATIONS:

The 2025-2026 Kern County Grand Jury recommends:

R1. By June 1, 2026, all incorporated cities in the County should have current Emergency Plans in place. The plans must be reviewed every 4 years. The plans should be coordinated with other local and regional authorities. (Finding F1)

R2. A field exercise incorporating the OES, along with local city resources, should be held at a minimum once every four years, allowing bottom-up input from on-the-ground responders. The first such exercise should occur not later than December 1, 2026. (Finding F4)

R3. The OES Manager is a critical position for the safety of residents. This position should never be left vacant and needs priority hiring. The process requires urgent attention and should be fully completed no later than April 1, 2026. (Finding F2)

R4. By June 1, 2026, a resident-friendly registration system should be implemented to prevent confusion and allow consistent, reliable communication of emergency notices to the public. (Findings F5, F6)

R5. By June 1, 2026, the Department of Aging and Adult Services should provide basic disaster response training to all In-Home Supportive Services (IHSS) staff. The IHSS should be encouraged to inform their clients about disaster preparation. (Findings F6, F9, F10)

R6. The KCSO's new geo-location software should be fully implemented and automatically update the OES command in real time. This should be completed by November 1, 2026. (Finding F8).

R7. Elderly and disabled residents should be assisted with preparing Go Bags by County or City volunteers. The Department of Aging and Adult Services should implement this by June 1, 2026. (Finding F6, F10)

R8. The ReadyKern form should include an option for residents to note they need assistance in emergencies. This should be implemented by April 1, 2026. (Finding F5)

**COMMENTS:**

The Grand Jury would like to thank the City and County staff who took time to answer many questions. They provided valuable insight into the management of disasters, particularly in responding to the needs of the disabled, non-ambulatory, and elderly. The staff were professional and courteous at all times, and have been directly responsible for protecting and, in some instances, saving residents' lives in times of emergency.

## NOTES:

- The Kern County Board of Supervisors should post a copy of this report where it will be available for public review.

- Persons wishing to receive an email notification of newly released reports may sign up at: https://www.kerncounty.com/grandjury

- Present and past Kern County Grand Jury Final Reports and Responses can be accessed on the Kern County Grand Jury website https://www.kerncounty.com/grandjury

## RESPONSE DEADLINE:

- **REQUESTED WITHIN 90 DAYS FROM:** The Kern County Board of Supervisors. Findings F1 - F12, Recommendations R1 - R8.

- **REQUESTED WITHIN 90 DAYS FROM**: Kern County Fire Department. Findings F1 - F7, and F9 - F12, Recommendations R1 - R4, and R8.

- **REQUESTED WITHIN 90 DAYS FROM**: Kern County Department of Aging and Adult Services. Findings F5, F6, F10, F11, and F12. Recommendations R4, R5, R7, and R8.

**RESPONSES ARE REQUIRED PURSUANT TO PENAL CODE §§933(c) AND 933.05:**

- **PRESIDING JUDGE**
  **SUPERIOR COURT OF CALIFORNIA**
  **COUNTY OF KERN**
  **1415 TRUXTUN AVENUE, SUITE 212**
  **BAKERSFIELD, CA 93301**

- **FOREMAN**
  **KERN COUNTY GRAND JURY**
  **1415 TRUXTUN AVENUE, SUITE 600**
  **BAKERSFIELD, CA 93301**

Reports issued by the Grand Jury do not identify individuals interviewed. Cal. Penal Code §929, requires that reports of the Grand Jury do not contain the name of any person or facts leading to the identity of any person who provides information to the Grand Jury.

# ADDENDUM A

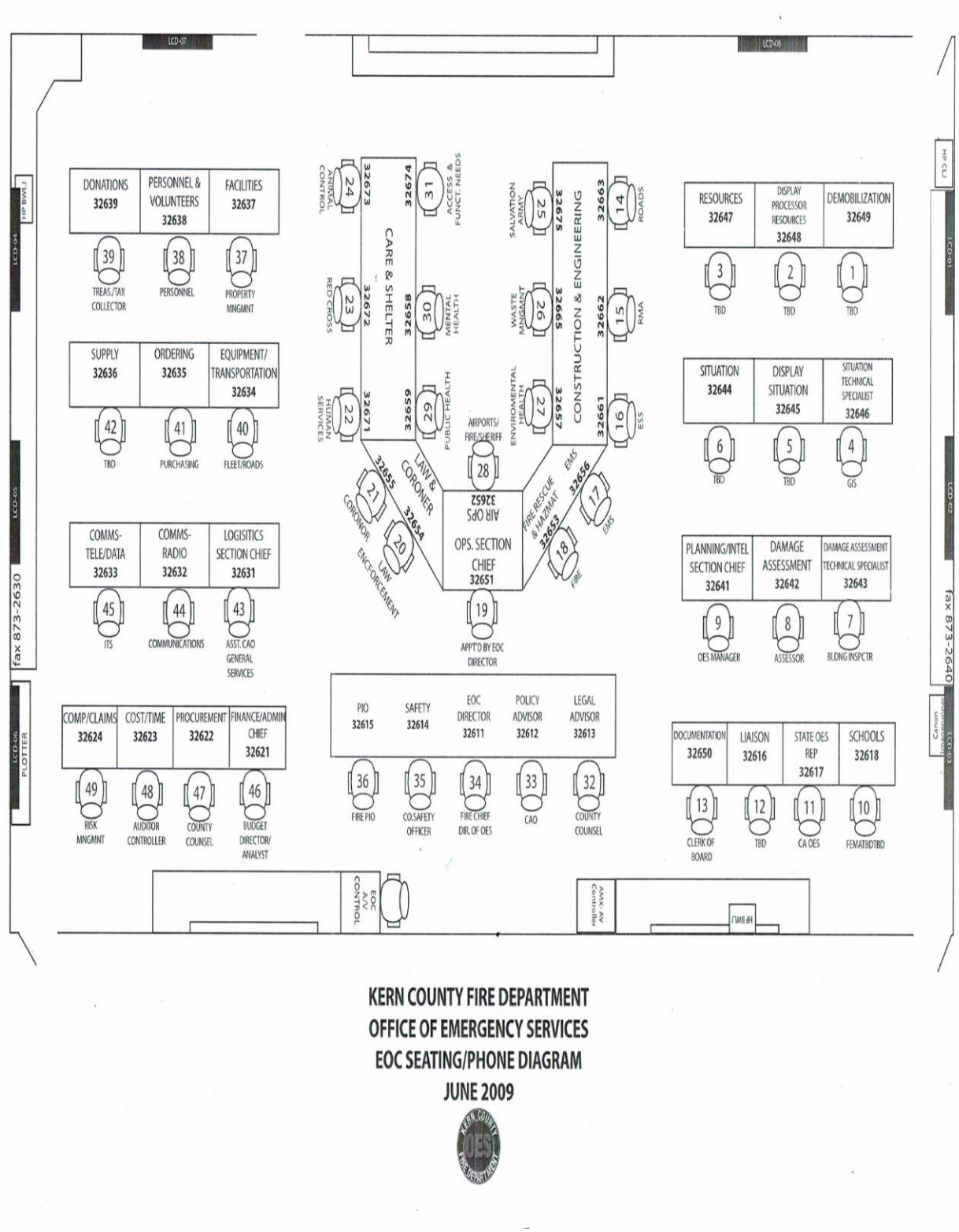



Image from the Kern County Fire Department

# ADDENDUM B




Picture of OES EOC showing layout of desks
including computers and identifying vests,
located at each station

# ADDENDUM C

## Evacuation Transportation Assistance During Disaster Response

1. When the Incident Commander issues an Evacuation Order or Evacuation Warning, Kern OES will activate the county's emergency telephone notification system [ReadyKern] to disseminate the warning information to the residents in the threatened geography who have registered to receive alerts. [approximately 10 minutes]

2. The ReadyKern message will include instructions for residents to call 855-264-6565, which is the Aging & Adult Services Elder Abuse Hotline and is staffed 24/7/365. Aging & Adult Services department staff speak with the constituent to fully understand the scope of need and complete an intake form, which is sent to the Kern EOC to an email account accessible by all Kern OES staff to ensure messages are not missed due to breaks/absences: evactransportation@kerncountyfire.org.

3. Upon receipt, Kern OES staff will make direct contact with the constituent to confirm their desire to evacuate and, if so, to confirm that transportation will be deployed to their location. [immediately, approximately 2 minutes]

4. Kern OES staff contacts the transportation provider, which at most events is handled by Kern Regional Transit, a unit of the Ken Public Works Dept. [immediately, approximately 2 minutes]

5. Kern Regional Transit then deploys the driver and van/bus to the constituent, who is often assisted into the vehicle by the driver, and transported to the mass care shelter. Residents are allowed to bring their pets to the shelter; animal sheltering is always conducted in close proximity to human sheltering operations and is supported by the Kern County Animal Services Dept. Service Animals are always allowed in the vehicle and inside the shelter.

# ADDENDUM D

## READYKERN REGISTRATION FORM

KERN COUNTY FIRE DEPARTMENT
OFFICE OF EMERGENCY SERVICES
ATTENTION: READYKERN PROGRAM
2601 PANORAMA DRIVE, BUILDING B
BAKERSFIELD, CA 93306

Please complete this form and return by mail to the Kern County Fire Department at the address provided above. (Fields in ***bold** are required.)

**To register online, visit www.ReadyKern.com.**

### REGISTER A RESIDENCE

***First Name:**_____ ***Last Name:**_____

***Address:**_____

***City:**_____ ***State:**_____ ***ZIP Code:**_____

***Primary Phone #:**_____ Secondary Phone #:_____

Primary Mobile Phone #:_____ Secondary Mobile Phone #:_____

Primary E-mail Address:_____ Secondary E-mail Address:_____

TDD/TTY Device #[1]:_____

**AND/OR**

### REGISTER A BUSINESS

***Business Name:**_____

***Contact First Name:**_____ ***Last Name:**_____

***Address:**_____

***City:**_____ ***State:**_____ ***ZIP Code:**_____

***Primary Phone #:**_____ Secondary Phone #:_____

Primary Mobile Phone #:_____ Secondary Mobile Phone #:_____

Primary E-mail Address:_____ Secondary E-mail Address:_____

TDD/TTY Device #[1]:_____

[1] **T**elecommunication **D**evice for the **D**eaf/**T**ele**ty**pewriter

Registration Form, 2017

ReadyKern Application Form
Image from ReadyKern Website

## Genasys

**KERN COUNTY, CA** – Emergencies can happen at any time, including wildfires, earthquakes, and floods. In the wake of disasters, it is repeatedly seen that every minute counts. To help our residents be better prepared for emergencies, the Kern County Fire Department and Kern County Office of Emergency Services have partnered with Genasys to divide the county into pre-established evacuation zones. This new Genasys Protect evacuation management and communication tool has been a project nearly two years in the making and is now live! We are excited to see the benefits it will bring to our community by reducing the time needed to give evacuation notifications.

- Go to protect.genasys.com to find your zone.
- Once you find your zone name, write it down and post it somewhere that is easy to find. Knowing your zone name will help you quickly identify if the status of your zone is changed due to an emergency.
- Authorities will use Zone names in emergency alerts to notify residents of which areas are affected. Sign up to receive emergency alerts at readykern.com.

### Frequently Asked Questions

#### What is the Genasys evacuation management tool, also known as Genasys Protect?

Genasys Protect is a platform utilized to allow communities and first responders to more effectively plan, communicate, and execute evacuations. The platform will be used countywide, including the County and all cities.

#### What is the Genasys Protect Community Site?

The Genasys Protect Community Site (protect.genasys.com) is a web-based platform for our community to find their evacuation zones and view emergency information. Residents can look up their address using the search bar.

Residents can also download the Genasys Protect App for iOS and Android, which will provide evacuation information to their mobile devices, including notifications if they choose to allow them. https://protect.genasys.com/download

The App allows individuals who live, follow, or are visiting zones to receive evacuation messaging as a critical alert (alarms when phones are in silent mode).

**Do I still need to sign up for ReadyKern to receive emergency notifications?**

Yes, residents in Kern County should sign up to receive emergency notifications via ReadyKern. Zone names will be used in ReadyKern notifications, so it is important to #KnowYourZone. Genasys Protect doesn't replace ReadyKern. It enhances its effectiveness.

Sign up to receive emergency notifications, readykern.com

**Why do we need evacuation zones?**

Pre-established evacuation zones help first responders and emergency service agencies prepare before an emergency strikes and help streamline the evacuation process, reducing confusion and allowing residents to evacuate quickly. It also ensures that first responders and community members are on the same page with the same information.

**How do I Find My Zone?**

Visit protect.genasys.com and type in your address in the search bar. Write the zone name down, memorize it, and post it in a high-traffic location, like on your refrigerator.

**Where does the information in Genasys Protect come from, and who keeps it updated?**

The Kern County Fire Department worked directly with Genasys to add and approve all information for the zones. Emergency response personnel update the status and information during emergencies.

Information provided by Genasys website

# ADDENDUM E

| Exhibit 3 — AFN Shelter Equipment List (per Trailer) | | |
|---|---|---|
| Equipment Item | Notes | |
| BEDDING | | |
| ADA Cots w/rolling rack | | 8 |
| Pool Noodles (18 per pk) | Protective barrier for ADA cots | 1 |
| portable playpen/bassinet | | 1 |
| MOBILITY SUPPORT | | |
| Manual Hoyer Lift w/ Lg sling | Transfer support | 1 |
| Hoyer lift Sling (various sizes) | | 4 |
| 1 8" Wheelchair with footrest | | 1 |
| Walker with folding seat | | 1 |
| Adjustable cane | | 1 |
| Folding Blind Cane with wrist strap | | 1 |
| Transfer Board | | 1 |
| Privacy curtains and curtain stand | | 3 |
| Wheelchair seat cushion 16x16x3 | | 2 |
| Grabbers | | 2 |
| Gravel Mats | | 2 |
| Threshold ramps | | 1 |
| 6' portable ramp | | 1 |
| Folding bedside commode | | 1 |
| Plastic portable urinal | | 5 |
| MEDICATION STORAGE | | |
| Refrigerator with lock | | 1 |
| HYGIENE: | | |
| infant Diapers-Size 1 (case) | | 1 |
| Infant Diapers-Size 2 (case) | | 1 |
| Infant Diapers-Size 3 (case) | | 1 |
| Infant Diapers-Size 4 (case) | | 1 |
| Infant Diapers-Size 5 (case) | | 1 |
| Infant Diapers-Size Newborn (case) | | 1 |

| | | |
|---|---|---|
| Infant Diaper Wipes (case) | | 1 |
| Chux: bed pads 23x36 (150 count/box) | | 1 |
| Pull up briefs, various sizes (case) | | 3 |
| Wipes Adult 1 case/12 pk | | 1 |
| Barrier Cream fragrance free loz 48 tubes/case | | 1 |
| Shower Bench | | 1 |
| Shower wheelchair | | 1 |
| Portable shower grab bars | | 2 |
| Portable shower caddy for toiletry supplies | | 4 |

| Exhibit 3 — AFN Shelter Equipment List (per Trailer) | | |
|---|---|---|
| Extendable shower head | | 2 |
| Long handled bath sponge | | 10 |
| 6 Quart wash basin | | 5 |
| Shower mats I f9"x1 '9" | | 2 |
| Cavicide 240z spray | | 2 |
| FEEDING | | |
| Disposable bibs- child (10/pack) | | 2 |
| Disposable infant spoons (8/pack) | | 1 |
| Bottles (12 per pk) | | 1 |
| disposable sippy cups (6 per pk) | | 2 |
| Bibs - Adult (300 count/case) | | 1 |
| Handle foam grips 3/8 inch (6 per pk) | | 1 |
| Drinking straws (100 count/box) | | 1 |
| Mini Food processor | Softened dietary needs | 1 |
| COMMUNICATIONS | | |
| Rubbermaid Audio Guard | Audio safety alert | 1 |
| Rubbermaid Safety cone | | 1 |
| Communication board | | 2 |
| UbiDuo 2 Wireless/ Carry Bag/ Power cord | | 1 |

| Exhibit 3 — AFN Shelter Equipment List (per Trailer) | | |
|---|---|---|
| Pet potty pads (35.5 x 23.5 in) 50ct | | 1 |
| animal waste bags 50rolls | | 1 |
| Laptop computer & Printer(for remote ASL/nonEnglish) | Remote ASL/language services | 2 |
| VISUAL SUPPORT | | |
| Magnifiers. 2"x4[1t] | | 4 |
| Magnifiers 5 x 7 | | 4 |
| Scrolling LED sign | | 1 |
| SENSORY SUPPORT | | |
| disposable earplugs - corded (200ct/box) & uncorded (100 ct/box) | | 2 |
| Over the ear Headphones | | 2 |
| POWER | | |
| Charger for GEL battery | | 1 |
| Charger for AGM battery | | 1 |
| Extension Cords | | 1 |
| SERVICE ANIMALS | | |
| Blankets - bedding for service animals 10yd per k | | 1 |
| Flea collar (6 count/box) | | 2 |
| Indoor pet relieving station | | 1 |

Notes:

1. UbiDuo and computer laptops/printers are NOT stored in the trailer due to potential damage. Equipment is staged with Kern DHS Sheltering staff for deployment.

2. Contact Animal Services for food and water bowels (sic) for Service Animals

Forms provided by the Department of Human Services

# APPENDICES

## Appendix A

State of California Planning Best Practices For County Emergency Plans
(First Ed. November 2021)
www.caloes.ca.gov

**Background**

On September 29, 2020, Governor Gavin Newsom signed AB-2968 – County Emergency Plans: Best Practices (Rodriguez) into California law. This amendment to California Government Code section 8593.9 requires Cal OES to develop best practices for counties developing and updating a county emergency plan, by January 1, 2022. This document aims to meet the requirements of that law.

**The Emergency Plan Definition**

An emergency plan is a document that defines the scope of preparedness and emergency management activities necessary for that jurisdiction to effectively respond to a large-scale incident or disaster. The government at each jurisdiction is responsible for ensuring that necessary and appropriate actions are taken to protect people, property, and the environment from the consequences of emergencies and disasters. An emergency plan formalizes how resources are to be used in diverse scenarios, and which courses of action should be taken so that the community has a plan for several types of response operations.

**Legal Requirements for an Emergency Plan**

Government Code section 8610 of the Emergency Services Act (ESA) permits cities and counties to form Local Disaster Councils (LDCs). If established, these councils are required to approve the development of emergency plans and send a copy of these plans to the State Office of Emergency Services.

Pursuant to Government Code section 8593.9, the California Governor's Office of Emergency Services (CalOES) is required to review ten (10) county emergency plans each year and confirm:

1. Whether the plan is consistent with CalOES' proposed best practices.
2. Whether the plan protects and accommodates vulnerable populations during
3. natural disasters.
4. Whether the plan has established procedures for alerting, evacuating, and sheltering individuals during an emergency.
5. Any other necessary and appropriate element, as determined by CalOES

An emergency plan is the base plan for the response operations that occur in a county. Emergency plans describing response operations may also be called:

- Comprehensive Emergency Management Plan (CEMP)
- Emergency Operations Plan (EOP)
- Facility Emergency Response Plan • General Plan – Safety Element
- County Emergency Management Plan (EMP) Assembly Bill 2311 (Brown, Chapter 520, 2016), which added California Government Code section 8593.3, requires each county and city to integrate access and functional needs upon the next update to its emergency response plan.

Assembly Bill 477 (Cervantes, Chapter 218, 2019), further amends California Government Code section 8593.3, requiring each county and city to include representatives from access and functional needs populations in the next regular update to its emergency plan. Specifically, jurisdictions must include internal and external stakeholders throughout each phase of the emergency planning process in:

- Emergency communications
- Emergency evacuations
- Emergency sheltering

Appendix B
Kern County Basic Emergency Plan
Introduction

THE KERN COUNTY EMERGENCY OPERATIONS PLAN ESTABLISHES AN EMERGENCY MANAGEMENT ORGANIZATION AND ASSIGNS FUNCTIONS AND TASKS CONSISTENT WITH CALIFORNIA'S STANDARDIZED EMERGENCY MANAGEMENT SYSTEM (SEMS) AND THE NATIONAL INCIDENT MANAGEMENT SYSTEM (NIMS).

THE PRESERVATION OF LIFE AND PROPERTY IS AN INHERENT RESPONSIBILITY OF ALL LEVELS OF GOVERNMENT. SINCE DISASTERS IN MANY DEVASTATING FORMS MAY STRIKE AT ANY TIME, THE COUNTY OF KERN ENDEAVORS TO SAVE LIVES AND MINIMIZE PROPERTY DAMAGE THROUGH PRIOR PLANNING, PREPAREDNESS MEASURES, AND TRAINING. SOUND EMERGENCY PLANS CARRIED OUT BY KNOWLEDGEABLE AND WELL-TRAINED PERSONNEL CAN AND WILL MINIMIZE LOSSES FROM ANY DISASTERS THAT MAY OCCUR.

AS DEFINED BY SEMS, AN OPERATIONAL AREA IS DEFINED AS AN INTERMEDIATE LEVEL OF THE STATE EMERGENCY SERVICES ORGANIZATION, CONSISTING OF A COUNTY AND ALL POLITICAL SUBDIVISIONS WITHIN THE COUNTY BOUNDARY. THE COUNTY OF KERN IS THE LEAD AGENCY FOR THE KERN OPERATIONAL AREA AND IS TASKED TO COORDINATE EMERGENCY ACTIVITIES BETWEEN THE COUNTY, CITIES AND SPECIAL DISTRICTS AND TO SERVE AS A COMMUNICATIONS LINK FOCUSING ON THE COLLECTION, PROCESSING AND DISSEMINATION OF VITAL DISASTER INFORMATION.

THE PLAN PROVIDES FOR THE INTEGRATION AND COORDINATION OF PLANNING EFFORTS OF THE COUNTY/OPERATIONAL AREA WITH THOSE OF ITS CITIES, SPECIAL DISTRICTS AND THE STATE. THE CONTENT IS BASED ON GUIDANCE PROVIDED BY THE CALIFORNIA EMERGENCY MANAGEMENT AGENCY, THE FEDERAL EMERGENCY MANAGEMENT AGENCY AND DEPARTMENT OF HOMELAND SECURITY. THE INTENT OF THE PLAN IS TO FACILITATE EMERGENCY RESPONSE AND SHORT-TERM RECOVERY BY PROVIDING A FRAMEWORK FOR RESPONSE TO ALL SIGNIFICANT EMERGENCIES, REGARDLESS OF THE NATURE OF THE EVENT.

THE PLAN IS COMPRISED OF FOUR MAJOR PARTS AS FOLLOWS:

- BASIC PLAN – OVERVIEW OF COUNTY/OPERATIONAL AREA'S EMERGENCY MANAGEMENT PROGRAM, EMERGENCY MANAGEMENT ORGANIZATION, AND CONCEPT OF EMERGENCY OPERATIONS
- GENERAL PROCEDURES – EMERGENCY PROCEDURES TO BE IMPLEMENTED BY EMPLOYEES AT THE TIME OF A MAJOR EMERGENCY OR DISASTER
- EMERGENCY OPERATIONS CENTER (EOC) PROCEDURES & ANNEXES – EOC PROCEDURES, ANNEX AND CHECKLISTS FOR EACH MAJOR EOC FUNCTION, AND RESOURCE AND CONTACT LISTS. (THIS SECTION WILL BE UPDATED IN 2009 TO BETTER SUPPORT THE NEWLY OPENED KERN COUNTY EOC)
- CONTINGENCY PLANS – EVENT-SPECIFIC INFORMATION AND EMERGENCY INSTRUCTIONS (E.G., TERRORISM). THE CONTINGENCY PLANS ARE SEPARATE DOCUMENTS THAT MAY BE IMPLEMENTED INDEPENDENT OF THE PLAN AND ARE INCORPORATED INTO THE PLAN BY REFERENCE.

© 2020 KERN COUNTY FIRE

# Exhibit U. Kern Oil & Refining Co., Permit Application for Authority to Construct for a Modification of Emission Unit with Valid PTO/Valid ATC, Application No. S-37-77-10 (Apr. 23, 2004)

S-37-77-10

# San Joaquin Valley Air Pollution Control District

www.valleyair.org

RECEIVED
APR 26 2004
SJVAPCD
Southern Region

## Permit Application For:

[ ] AUTHORITY TO CONSTRUCT (ATC) - New Emission Unit.
[X] AUTHORITY TO CONSTRUCT (ATC) - Modification Of Emission Unit With Valid PTO/Valid ATC.
[ ] AUTHORITY TO CONSTRUCT (ATC) - Renewal of Valid Authority to Construct.
[ ] PERMIT TO OPERATE (PTO) - Existing Emission Unit Now Requiring a Permit to Operate.

1. PERMIT TO BE ISSUED TO: Kern Oil & Refining Co. (Kern)

2. MAILING ADDRESS:
STREET/P.O. BOX: 7724 E. Panama Lane
CITY: Bakersfield STATE: CA 9-DIGIT ZIP CODE: 93307-9210

3. LOCATION WHERE THE EQUIPMENT WILL BE OPERATED:
STREET: same as above CITY:
/4 SECTION TOWNSHIP RANGE

WITHIN 1,000 FT OF A SCHOOL? [ ] YES [X] NO

S.I.C. CODE(S) OF FACILITY (If known): 2911

4. GENERAL NATURE OF BUSINESS: Petroleum Refining

INSTALL DATE:

5. TITLE V PERMIT HOLDERS ONLY: Do you request a COC (EPA Review) prior to receiving your ATC? [X] YES [ ] NO

6. DESCRIPTION OF EQUIPMENT OR MODIFICATION FOR WHICH APPLICATION IS MADE (include Permit #'s if known, and use additional sheets if necessary)

(1) Modify Diesel Hydrotreater (DHT) Unit to for production of ultra-low sulfur diesel (ULSD) mandated by California and federal requirements. [Permit No. S-37-77-X]

(2) See attached equipment lists, cover letter, prior correspondence dated January 27, 2004 and March 12, 2004 for additional project details.

(3) Request is made for Certificate of Conformity (COC) with the application.

7. PERMIT REVIEW PERIOD: Do you request a three- or ten-day period to review the draft Authority to Construct permit? Please note that checking "YES" will delay issuance of your final permit by a corresponding number of working days. See instructions for more information on this review process.
[ ] 3-day review
[X] 10-day review
[ ] No review requested

8. HAVE YOU EVER APPLIED FOR AN ATC OR PTO IN THE PAST? [X] YES [ ] NO
If yes, ATC/PTO #:

9. HAVE ALL NECESSARY LAND-USE AUTHORIZATIONS BEEN OBTAINED? (If "No" is checked, please attach explanation.) [X] YES [ ] NO

10. IS THIS APPLICATION SUBMITTED AS THE RESULT OF EITHER A NOTICE OF VIOLATION OR A NOTICE TO COMPLY? [ ] YES [X] NO
If yes, NOV/NTC #:

**Optional Section**

11. CHECK WHETHER YOU ARE A PARTICIPANT IN EITHER OF THESE VOLUNTARY PROGRAMS:
"SPARE THE AIR"
[ ]Yes [X ]No [ ]Send info
"INSPECT"
[ ]Yes [X ]No [ ]Send info

12. TYPE OR PRINT NAME OF APPLICANT: CHAD TUTTLE
TITLE OF APPLICANT: MGR, ENVIRONMENTAL AFFAIRS

13. SIGNATURE OF APPLICANT: Chad Tuttle DATE: APRIL 23, 2004
PHONE #: (661) 845-0761
FAX #: (661) 845-0330
E-MAIL:

RECEIVED

FOR APCD USE ONLY:

DATE STAMP: APR 27 2004
FINANCE
SJVUAPCD

FILING FEE RECEIVED: $ 120.- CHECK #: 5-1995 360.-
DATE PAID: PM 4/23/04

Northern Regional Office * 4230 Kiernan Avenue, Suite 130 * Modesto, California 95356-9321 * (209) 557-6400 * FAX (209) 557-6475
Central Regional Office * 1990 East Gettysburg Avenue * Fresno, California 93726-0244 * (559) 230-5900 * FAX (559) 230-6061

5-1040995 5-37

S.T. S-37-118-0

# San Joaquin Valley Air Pollution Control District

www.valleyair.org

## Permit Application For:

[X] AUTHORITY TO CONSTRUCT (ATC) - New Emission Unit.
[ ] AUTHORITY TO CONSTRUCT (ATC) - Modification Of Emission Unit With Valid PTO/Valid ATC.
[ ] AUTHORITY TO CONSTRUCT (ATC) - Renewal of Valid Authority to Construct.
[ ] PERMIT TO OPERATE (PTO) - Existing Emission Unit Now Requiring a Permit to Operate.

RECEIVED APR 2 [illegible]

1. PERMIT TO BE ISSUED TO:
Kern Oil & Refining Co. (Kern)

2. MAILING ADDRESS:
STREET/P.O. BOX: 7724 E. Panama Lane
CITY: Bakersfield STATE: CA 9-DIGIT ZIP CODE: 93307-9210

3. LOCATION WHERE THE EQUIPMENT WILL BE OPERATED:
STREET: same as above CITY:
/4 SECTION TOWNSHIP RANGE

WITHIN 1,000 FT OF A SCHOOL? [ ] YES [X] NO

S.I.C. CODE(S) OF FACILITY (If known): 2911

4. GENERAL NATURE OF BUSINESS: Petroleum Refining

INSTALL DATE:

5. TITLE V PERMIT HOLDERS ONLY: Do you request a COC (EPA Review) prior to receiving your ATC? [X] YES [ ] NO

6. DESCRIPTION OF EQUIPMENT OR MODIFICATION FOR WHICH APPLICATION IS MADE (include Permit #'s if known, and use additional sheets if necessary)

(1) Install new Reformer Facility for production of ultra-low sulfur diesel (ULSD) mandated by California and federal requirements.

(2) See attached equipment lists, cover letter, prior correspondence dated January 27, 2004 and March 12, 2004 for additional project details.

(3) Request is made for Certificate of Conformity (COC) with the application.

7. PERMIT REVIEW PERIOD: Do you request a three- or ten-day period to review the draft Authority to Construct permit? Please note that checking "YES" will delay issuance of your final permit by a corresponding number of working days. See instructions for more information on this review process.
[ ] 3-day review
[X] 10-day review
[ ] No review requested

8. HAVE YOU EVER APPLIED FOR AN ATC OR PTO IN THE PAST? [X] YES [ ] NO
If yes, ATC/PTO #:

9. HAVE ALL NECESSARY LAND-USE AUTHORIZATIONS BEEN OBTAINED? (If "No" is checked, please attach explanation.) [X] YES [ ] NO

10. IS THIS APPLICATION SUBMITTED AS THE RESULT OF EITHER A NOTICE OF VIOLATION OR A NOTICE TO COMPLY? [ ] YES [X] NO
If yes, NOV/NTC #:

**Optional Section**

11. CHECK WHETHER YOU ARE A PARTICIPANT IN EITHER OF THESE VOLUNTARY PROGRAMS:
"SPARE THE AIR"
[ ]Yes [X ]No [ ]Send info
"INSPECT"
[ ]Yes [X ]No [ ]Send info

12. TYPE OR PRINT NAME OF APPLICANT: CHAD TUTTLE
TITLE OF APPLICANT: MGR, ENVIRONMENTAL AFFAIRS

13. SIGNATURE OF APPLICANT: M Chad Tuttle DATE: APRIL 23, 2004
PHONE #: (661) 845-0761
FAX #: (661) 845-0330
E-MAIL:

FOR APCD USE ONLY:

DATE STAMP: RECEIVED APR 27 2004 FINANCE SJVUAPCD

FILING FEE RECEIVED: $ 120.— CHECK #: 51995 360.—
DATE PAID: PM 4/23/04 MP



PEXH 000522

5-1040995 5-37

S-37-119-0

# San Joaquin Valley Air Pollution Control District

www.valleyair.org

RECEIVED
APR 2 6 2004
SJVAPCD
Southern Region

## Permit Application For:

[X] AUTHORITY TO CONSTRUCT (ATC) - New Emission Unit.
[ ] AUTHORITY TO CONSTRUCT (ATC) - Modification Of Emission Unit With Valid PTO/Valid ATC.
[ ] AUTHORITY TO CONSTRUCT (ATC) - Renewal of Valid Authority to Construct.
[ ] PERMIT TO OPERATE (PTO) - Existing Emission Unit Now Requiring a Permit to Operate.

1. PERMIT TO BE ISSUED TO:
Kern Oil & Refining Co. (Kern)

2. MAILING ADDRESS:
STREET/P.O. BOX: 7724 E. Panama Lane
CITY: Bakersfield STATE: CA 9-DIGIT ZIP CODE: 93307-9210

3. LOCATION WHERE THE EQUIPMENT WILL BE OPERATED:
STREET: same as above CITY:
/4 SECTION TOWNSHIP RANGE

WITHIN 1,000 FT OF A SCHOOL? [ ] YES [X] NO

S.I.C. CODE(S) OF FACILITY (If known): 2911

4. GENERAL NATURE OF BUSINESS: Petroleum Refining

INSTALL DATE:

5. TITLE V PERMIT HOLDERS ONLY: Do you request a COC (EPA Review) prior to receiving your ATC? [X] YES [ ] NO

6. DESCRIPTION OF EQUIPMENT OR MODIFICATION FOR WHICH APPLICATION IS MADE (include Permit #'s if known, and use additional sheets if necessary)

(1) Install new Sulfur Recovery Facility for production of ultra-low sulfur diesel (ULSD) mandated by California and federal requirements. Facility includes Claus Section, Amine Section and Sour Water Stripping Section.

(2) See attached equipment lists, cover letter, prior correspondence dated January 27, 2004 and March 12, 2004 for additional project details.

(3) Request is made for Certificate of Conformity (COC) with the application.

7. PERMIT REVIEW PERIOD: Do you request a three- or ten-day period to review the draft Authority to Construct permit? Please note that checking "YES" will delay issuance of your final permit by a corresponding number of working days. See instructions for more information on this review process.
[ ] 3-day review
[X] 10-day review
[ ] No review requested

8. HAVE YOU EVER APPLIED FOR AN ATC OR PTO IN THE PAST? [X] YES [ ] NO If yes, ATC/PTO #:

9. HAVE ALL NECESSARY LAND-USE AUTHORIZATIONS BEEN OBTAINED? (If "No" is checked, please attach explanation.) [X] YES [ ] NO

10. IS THIS APPLICATION SUBMITTED AS THE RESULT OF EITHER A NOTICE OF VIOLATION OR A NOTICE TO COMPLY? [ ] YES [X] NO If yes, NOV/NTC #:

**Optional Section**

11. CHECK WHETHER YOU ARE A PARTICIPANT IN EITHER OF THESE VOLUNTARY PROGRAMS:
"SPARE THE AIR"
[ ]Yes [X ]No [ ]Send info
"INSPECT"
[ ]Yes [X ]No [ ]Send info

12. TYPE OR PRINT NAME OF APPLICANT: CHAD TUTTLE
TITLE OF APPLICANT: MGR, ENVIRONMENTAL AFFAIRS

13. SIGNATURE OF APPLICANT: Chad Tuttle DATE: APRIL 23, 2004
PHONE #: (661) 845-0761
FAX #: (661) 845-0338
E-MAIL:

RECEIVED

FOR APCD USE ONLY:

| DATE STAMP: APR 27 2004 | FILING FEE RECEIVED: $ 120.- CHECK #: 57995 360.- |
|---|---|

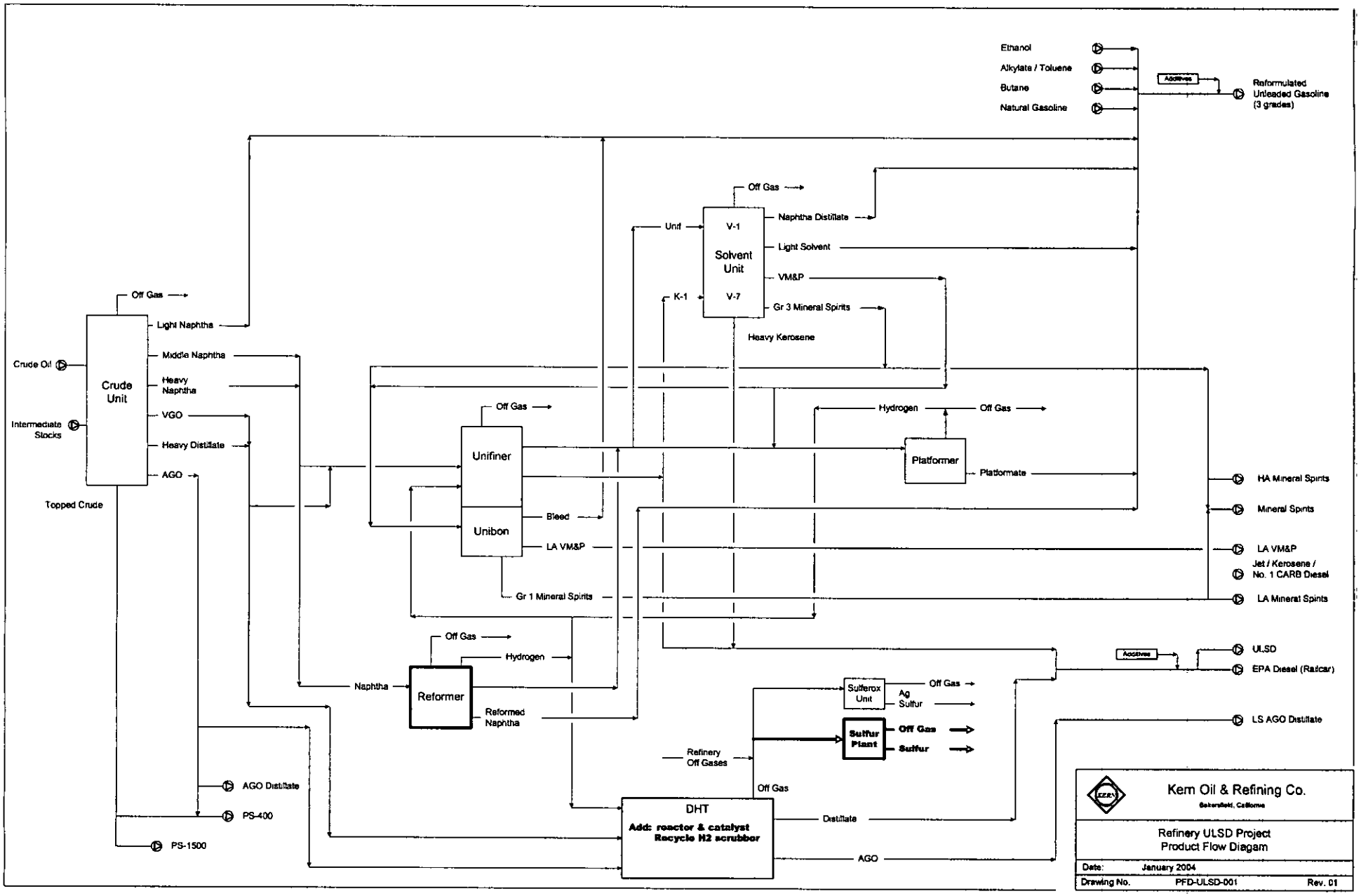


S-1040995 S-37

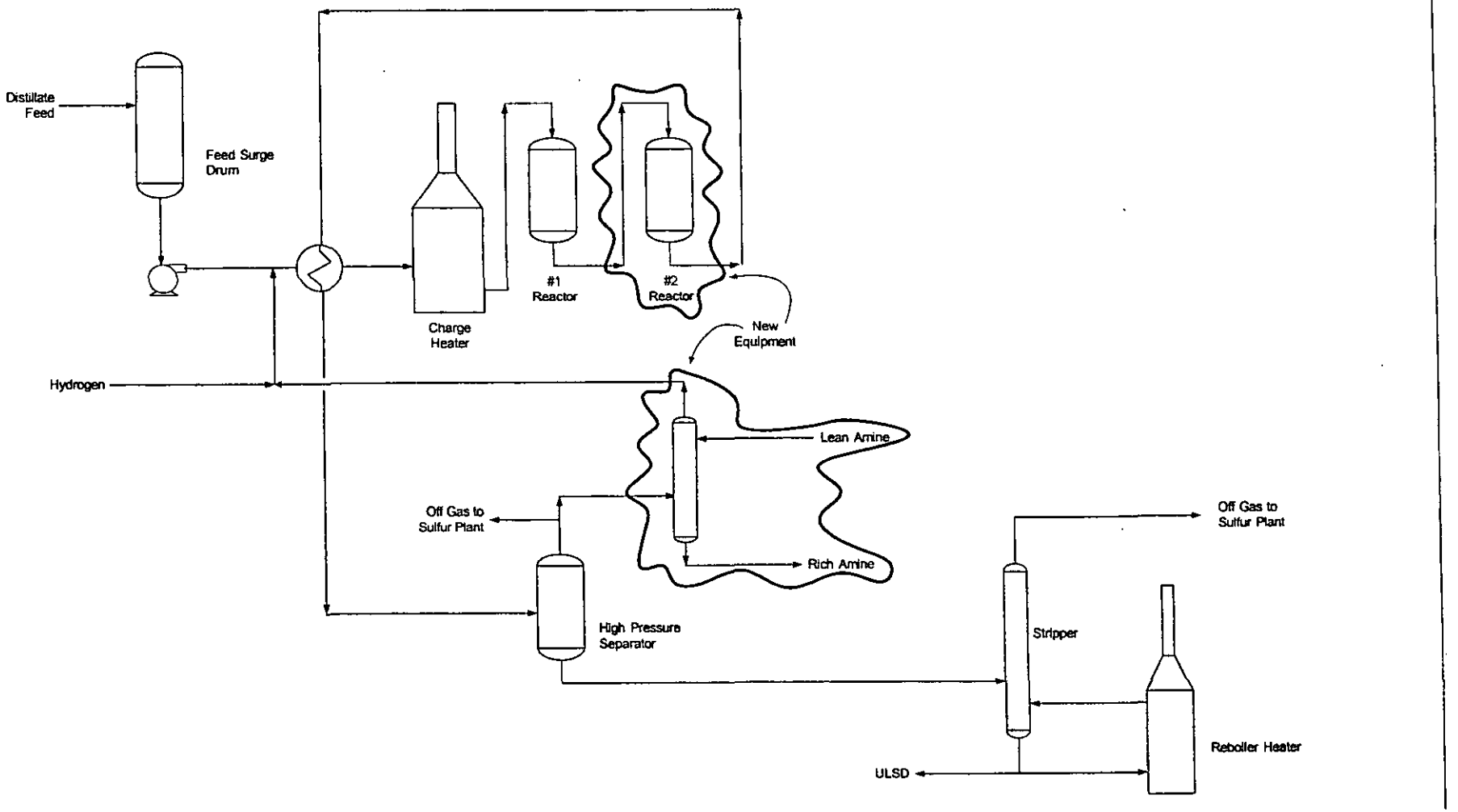
RECEIVED
SJVAPCD
Southern Region

RECEIVED
APR 2 6 2004
SJVAPCD
Southern Region

# Attachment No. 1
# **DHT Block Flow**


Ethanol
Alkylate / Toluene
Butane
Natural Gasoline
Additives
Reformulated Unleaded Gasoline (3 grades)
Off Gas
Unif
V-1
Solvent Unit
V-7
K-1
Naphtha Distillate
Light Solvent
VM&P
Gr 3 Mineral Spirits
Heavy Kerosene
Crude Oil
Intermediate Stocks
Crude Unit
Topped Crude
Light Naphtha
Middle Naphtha
Heavy Naphtha
VGO
Heavy Distillate
AGO
Unifiner
Unibon
Bleed
LA VM&P
Gr 1 Mineral Spirits
Hydrogen
Platformer
Platformate
HA Mineral Spirits
Mineral Spirits
LA VM&P
Jet / Kerosene / No. 1 CARB Diesel
LA Mineral Spirits
Naphtha
Reformer
Reformed Naphtha
Sulferox Unit
Ag Sulfur
Sulfur Plant
Refinery Off Gases
ULSD
EPA Diesel (Railcar)
LS AGO Distillate
AGO Distillate
PS-400
PS-1500
DHT
Add: reactor & catalyst
Recycle H2 scrubber
Distillate
AGO
Kern Oil & Refining Co.
Bakersfield, California
Refinery ULSD Project
Product Flow Diagam
Date: January 2004
Drawing No. PFD-ULSD-001
Rev. 01

PEXH 000525




Kern Oil and Refining Co.
Bakersfield, California

DHT Unit
Process Flow Diagram

Date: January 2004

Drawing No. Rev. 01

Attachment No. 2

# DHT (New) Equipment List

| KERN OIL & REFINING CO. - ULSD PROJECT<br>EXISTING DIESEL HYDROTREATER - ADDITIONAL/MODIFIED EQUIPMENT | |
|---|---|
| **EQUIPMENT** | **DESCRIPTION** |
| ***Vessels*** | Add Second Reactor<br><br>Add Inlet Distributors To Reactors<br><br>Add Recyle Gas Scrubber |
| ***Heaters*** | Upgrade Existing Feed Heater (Increase to 15.0 MMBtu/hr)<br><br>Upgrade Existing Stripper Reboiler Heater (Increase to 15.0 MMBtu/hr) |
| ***Pumps*** | |
| ***Compressors*** | |

**Kern Oil & Refining Co.**
**Facility # S - 37**

**Fugitive Component Count - Proposed Reformer Complex**

| Equipment Type | Service | Component Count (Naphtha Hydrotreater) | Component Count (Naphtha Reformer) | Component Count (Naphtha Splitter) | Total Component Count 2X Factor | Annual Factor, lbs/yr CAPCOA | Annual Factor, lbs/hr CAPCOA | TOC wt% VOC | Total VOC Rate lbs/day |
|---|---|---|---|---|---|---|---|---|---|
| Valves | Gas | | | | 0 | | 0.000128 | N/A | 0.00 |
| | Light Liquid | | | | 0 | | 0.000128 | N/A | 0.00 |
| | Heavy Liquid | | | | 0 | | 0.000128 | N/A | 0.00 |
| | All | 300 | 300 | 127 | 1454 | 1.12606 | 0.000128 | N/A | 4.47 |
| Pump Seals | Light Liquid | | | | 0 | | 0.003755 | N/A | 0.00 |
| | Heavy Liquid | | | | 0 | | 0.003755 | N/A | 0.00 |
| | All | 16 | 10 | 4 | 60 | 32.8933 | 0.003755 | N/A | 5.41 |
| Compressor Seals | Gas | 12 | 12 | 0 | 48 | 1.6847 | 0.000192 | N/A | 0.11 |
| Pressure Relief Valves | Gas | 11 | 17 | 1 | 58 | 9.5683 | 0.001092 | N/A | 1.52 |
| Connectors | Gas | | | | 0 | | | N/A | 0.00 |
| Open-Ended Lines | All | 5 | 5 | 5 | 30 | 44.4 | 0.005068 | N/A | 3.65 |
| Flanges | Gas | | | | 0 | | 0.000582 | N/A | 0.00 |
| | Light Liquid | | | | 0 | | 0.000582 | N/A | 0.00 |
| | Heavy Liquid | | | | 0 | | 0.000582 | N/A | 0.00 |
| | All | 300 | 900 | 168 | 2736 | 0.5096 | 0.000582 | N/A | 38.22 |
| Drains | All | 15 | 11 | 3 | 58 | 1.2066 | 0.000138 | N/A | 0.19 |
| Others | All | | | | 0 | 2.6116 | 0.000298 | N/A | 0.00 |
| Threaded Connection | All | 100 | 200 | 235 | 1070 | 0.2462 | 0.000028 | N/A | 0.72 |
| Sampling Lines | Gas | | | | 0 | | | N/A | 0.00 |
| | Light Liquid | | | | 0 | | | N/A | 0.00 |
| | Heavy Liquid | | | | 0 | | | N/A | 0.00 |
| Sampling Connections | All | 10 | 10 | 10 | 60 | | 0.000298 | N/A | 0.43 |
| | | | | | | | | Total | 54.71 |

Attachment No. 3

# Sulfur Facility Equipment List

| KERN OIL & REFINING CO.<br>NEW SULFUR RECOVERY UNIT | |
|---|---|
| **EQUIPMENT** | **DESCRIPTION** |
| ***Columns*** | Desuperheater/Contact Condensor |
| ***Vessels*** | Acid Gas K.O. Drum<br>Ammonia Gas K.O. Drum |
| ***Reactors*** | No. 1, No. 2, No. 3 Converter<br>& Hydrogenation Reactor |
| **Exchangers** | Waste Heat Boiler<br>No. 1 Condenser<br>No. 2 Condenser<br>No. 3 Condenser<br>No. 4 Condenser<br>No. 1 Reheater<br>No. 2 Reheater<br>No. 3 Reheater<br>Reactor Effluent Cooler<br>Contact Cond Air Cooler<br>Contact Cond Water Cooler |
| ***Furnaces*** | Reaction Furnace<br>Incinerator<br>Incinerator Stack<br>Reducing Gas Generator |
| ***Pumps*** | Acid Gas KO Drum Pump (2)<br>Ammonia Gas KO Drum Pump (2)<br>Sulfur Transfer Pump (2)<br>Desuperheater Circ. Pump (2)<br>Contact Condenser Circ. Pump (2) |
| ***Blowers*** | Combustion Air Blower (2) |
| ***Ejectors*** | Sulfur Pit Vent Eductor |
| ***Concrete Pits*** | Sulfur Pit |

| NEW AMINE SECTION EQUIPMENT LIST | DESCRIPTION |
|---|---|
| ***Columns*** | HP Amine Absorber<br>LP Amine Absorber<br>Amine Regenerator |
| ***Vessels*** | Rich Amine Flash Drum<br>Regenerator Overhead Accumulator<br>Reboiler Condensate Drum<br>Amine Sump<br>Amine Surge Drum |
| ***Exchangers*** | Lean Amine Cooler<br>Lean/Rich Amine Exchanger<br>Regenerator Reboiler<br>Regenerator Overhead Condenser |
| ***Pumps*** | Lean Amine Pump (2)<br>Lean Amine Booster Pump (2)<br>Regenerator Reflux Pump (2)<br>Amine Sump Pump (1) |
| ***Filters*** | Lean Amine Particle Filter<br>Lean Amine Carbon Filter<br>Lean Amine Post Carbon Filter<br>Drains (10) |

| KERN OIL & REFINING CO. - ULSD PROJECT<br>NEW SOUR WATER STRIPPING SECTION | |
|---|---|
| **EQUIPMENT** | **DESCRIPTION** |
| ***Columns*** | Stripper Tower |
| ***Vessels*** | Feed Drum<br>Steam Reboiler<br>Overhead Receiver |
| ***Exchangers*** | Effluent Coolers (4)<br>Bottoms Finfan |
| ***Pumps*** | Feed Pump (2)<br>Recovered Hydrocarbon Pump (2)<br>O.H.Reflux Pump (2) |
| ***Drains*** | Section Drains (6) |

**Kern Oil & Refining Co.**
**Facility # S - 37**

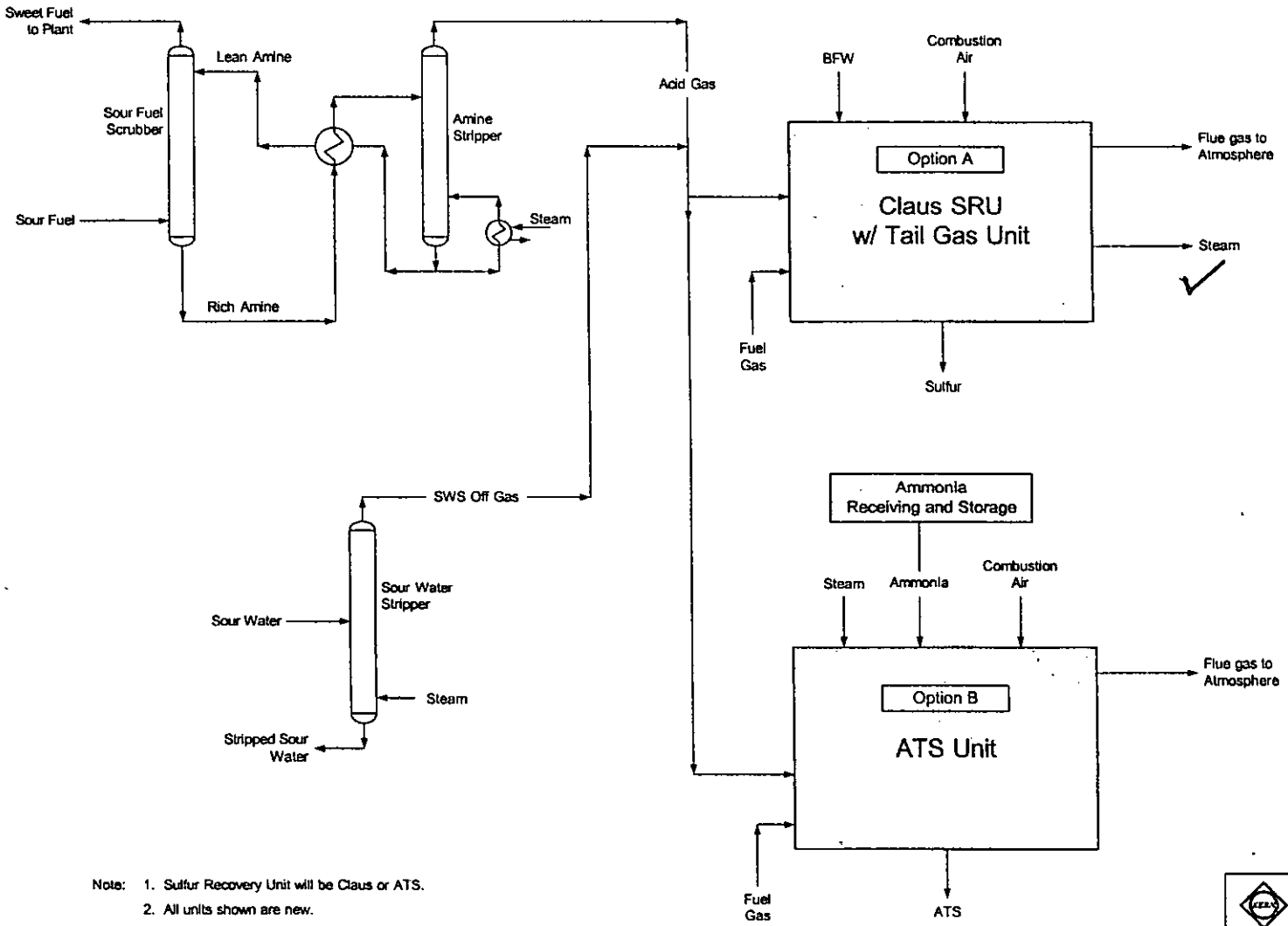
**Fugitive Component Count - Proposed Claus-TGTU/Amine/SWS/Incinerator Facility**

| Equipment Type | Service | Component Count | Component Count 2X Factor | Annual Factor, lbs/yr CAPCOA | Annual Factor, lbs/hr CAPCOA | TOC wt% VOC | Total VOC Rate lbs/day |
|---|---|---|---|---|---|---|---|
| Valves | Gas | | 0 | | 0.000128 | N/A | 0.00 |
| | Light Liquid | | 0 | | 0.000128 | N/A | 0.00 |
| | Heavy Liquid | | 0 | | 0.000128 | N/A | 0.00 |
| | All | 20 | 40 | 1.12606 | 0.000128 | N/A | 0.12 |
| Pump Seals | Light Liquid | | 0 | | 0.003755 | N/A | 0.00 |
| | Heavy Liquid | | 0 | | 0.003755 | N/A | 0.00 |
| | All | 6 | 12 | 32.8933 | 0.00375 | N/A | 1.08 |
| Compressor Seals | Gas | | 0 | 1.6847 | 0.000192 | N/A | 0.00 |
| Pressure Relief Valves | Gas | 4 | 8 | 9.5683 | 0.001092 | N/A | 0.21 |
| Connectors | Gas | | 0 | | | N/A | 0.00 |
| Open-Ended Lines | All | | 0 | 44.4 | 0.005068 | N/A | 0.00 |
| Flanges | Gas | | 0 | | 0.000582 | N/A | 0.00 |
| | Light Liquid | | 0 | | 0.000582 | N/A | 0.00 |
| | Heavy Liquid | | 0 | | 0.000582 | N/A | 0.00 |
| | All | 60 | 120 | 0.5096 | 0.000582 | N/A | 1.68 |
| Drains | All | | 0 | 1.2066 | 0.000138 | N/A | 0.00 |
| Others | All | | 0 | 2.6116 | 0.000298 | N/A | 0.00 |
| Threaded Connection | All | 30 | 60 | 0.2462 | 0.000028 | N/A | 0.04 |
| Sampling Lines | Gas | | 0 | | | N/A | 0.00 |
| | Light Liquid | | 0 | | | N/A | 0.00 |
| | Heavy Liquid | | 0 | | | N/A | 0.00 |
| Sampling Connections | All | 20 | 40 | | 0.000298 | N/A | 0.29 |
| | | | | | | Total | 3.42 |

Note 1: Include all systems in amine service. Sour water streams are exempt from counting.

Attachment No. 4

**Sulfur Facility Block Flow**




Note: 1. Sulfur Recovery Unit will be Claus or ATS.
2. All units shown are new.

Kern Oil and Refining Co.
Bakersfield, California

Sulfur Recovery Unit
Process Flow Diagram

Date: January 2003
Drawing No. Rev. 01

ATS = Ammonium Thiosulfate

Attachment No. 5

# Reformer Facility Equipment List

**EQUIPMENT LIST FOR**
**NEW REFORMER (HYDROTREATER SECTION)**

1. ***Fired Heaters:***

   Charge (11.1 MMBtu/hr)
   Stripper Reboiler (~~18.9~~ 12.6 MMBtu/hr)

2. ***Heat Exchangers:***

   H.P. Feed/Effluent
   H.P. Effluent Cooler
   Stripper Product Cooler
   Stripper O.H. Cooler
   Stripper Bottoms/Feed

3. **Air Coolers:**

   H.P. Effluent Cooler
   Stripper O.H. Condenser
   Product Cooler

4. ***Vessels:***

   Reactor
   Feed Surge Drum
   Compressor Suction Drum
   High Pressure Separator
   Stripper Tower
   Stripper Overhead Accumulator

5. ***Compressors:***

   H2 Makeup (2)
   H2 Recycle (2)

6. ***Pumps:***

   Charge (2)
   Stripper Reflux (2)
   Stripper Reboiler (2)

7. ***Drains:***

   Unit Drains (20)

**EQUIPMENT LIST FOR**
**NEW REFORMER (REFORMER SECTION)**

***1. Fired Heaters:***

Charge 1 (25.7 MMBtu/hr)
Charge 2 (13.4 MMBtu/hr)
Charge 3 (8.9 MMBtu/hr)
Splitter Reboiler (8.3 MMBtu/hr)

***2. Heat Exchangers:***

H.P. Effluent Cooler
Splitter O.H. Cooler
Splitter Feed/Effluent
Splitter Product Cooler
Light Reformate Cooler
Side Stripper Reboiler Heater

***3. Air Coolers:***

H.P. Effluent Cooler
Splitter O.H. Cooler
Splitter Product Cooler
Light Reformate Cooler

***4. Vessels:***

Reactors (3)
Feed Surge Drum
Compressor Suction Drum
High Pressure Separator
Splitter Tower
Splitter Side Stripper
Splitter O.H. Accumulator

***5. Compressors:***

H2 Recycle (2)

***6. Pumps:***

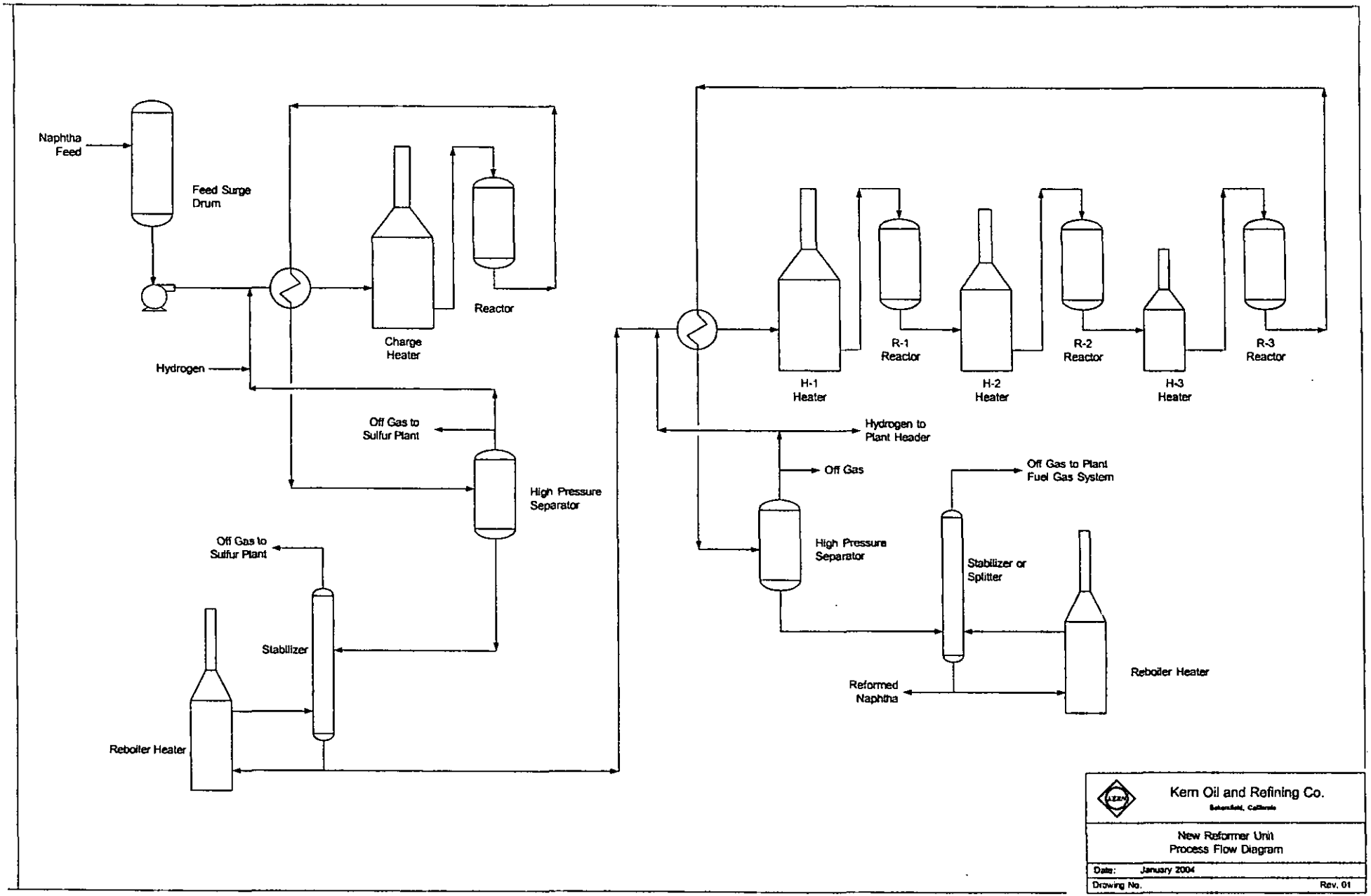
Charge (2)
Splitter Reflux (2)
Splitter Reboiler (2)

***7. Drains:***

Section Drains (30)

Attachment No. 6

# Reformer Facility Block Flow


Naphtha Feed
Feed Surge Drum
Charge Heater
Reactor
Hydrogen
Off Gas to Sulfur Plant
High Pressure Separator
Off Gas to Sulfur Plant
Stabilizer
Reboiler Heater
H-1 Heater
R-1 Reactor
H-2 Heater
R-2 Reactor
H-3 Heater
R-3 Reactor
Hydrogen to Plant Header
Off Gas
Off Gas to Plant Fuel Gas System
High Pressure Separator
Stabilizer or Splitter
Reboiler Heater
Reformed Naphtha
Kern Oil and Refining Co.
Bakersfield, California
New Reformer Unit
Process Flow Diagram
Date: January 2004
Drawing No.
Rev. 01

Attachment No. 7

**Application Forms**

Attachment No. 8

# Compliance Certification Form

# San Joaquin Valley
# Unified Air Pollution Control District

## TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

### I. TYPE OF PERMIT ACTION (Check appropriate box)

[X] SIGNIFICANT PERMIT MODIFICATION
[ ] MINOR PERMIT MODIFICATION
[ ] ADMINISTRATIVE AMENDMENT

| COMPANY NAME: Kern Oil & Refining Co. (Kern) | FACILITY ID: S -37 |
|---|---|
| 1. Type of Organization: [X] Corporation [ ] Sole Ownership [ ] Government [ ] Partnership [ ] Utility | |
| 2. Owner's Name: Kern Oil & Refining Co. (Kern) | |
| 3. Agent to the Owner: na | |

### II. COMPLIANCE CERTIFICATION *(Read each statement carefully and initial all circles for confirmation):*

(30) Based on information and belief formed after reasonable inquiry, the source identified in this application will continue to comply with the applicable federal requirement(s).

(30) Based on information and belief formed after reasonable inquiry, the source identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.

(30) Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.

(30) Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

Bruce Cogswell
Signature of Responsible Official

4-23-04
Date

Bruce W. Cogswell
Name of Responsible Official (please print)

Vice President
Title of Responsible Official (please print)

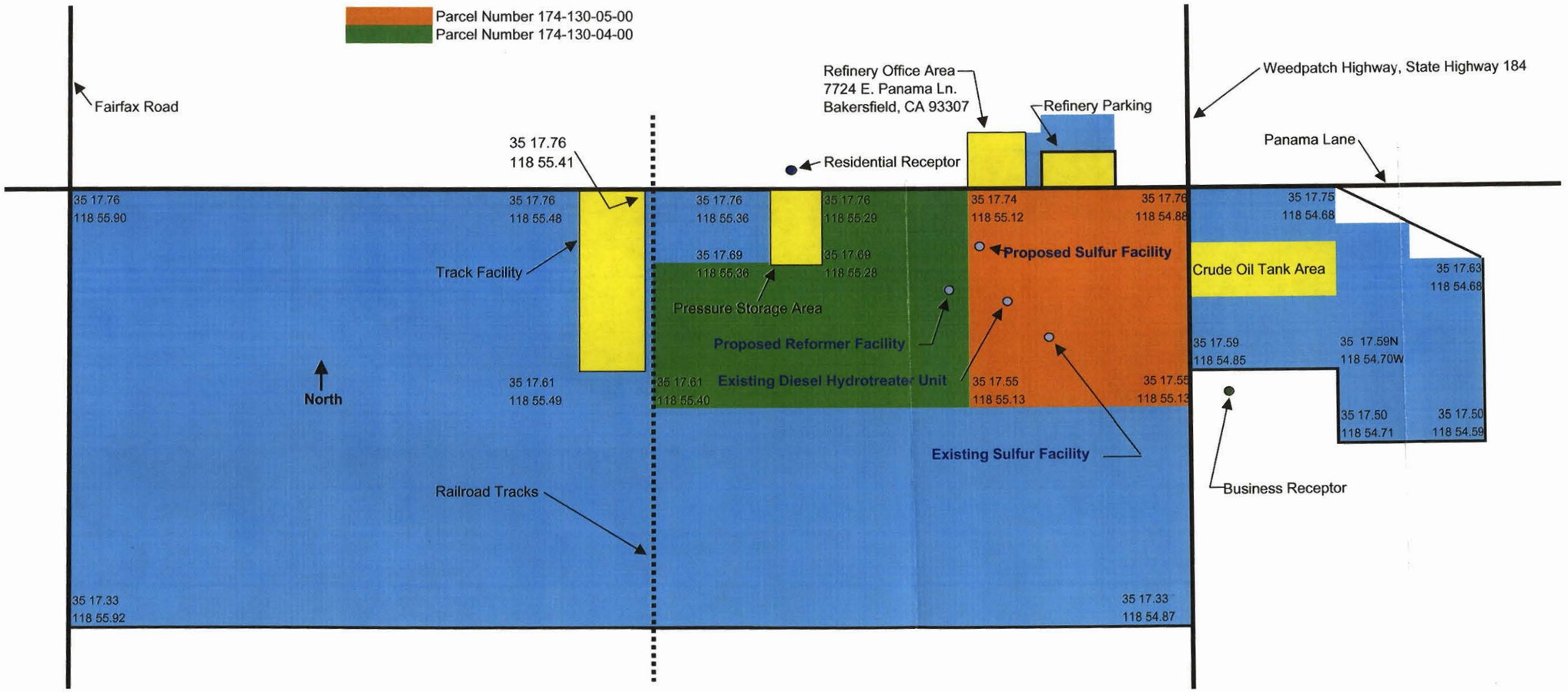
Attachment No. 9

**Updated Plot Map w/Parcel Numbers**

## Coordinates | Kern Oil & Refining Co. | Ultra-Low Sulfur Diesel Project

| Permit Number | Permit Description | Longitude Degrees | Minutes | Seconds | Latitude Degrees | Minutes | Seconds | |
|---|---|---|---|---|---|---|---|---|
| S-37-77 | Exisiting DHT Unit | 35 | 17 | 64 (N) | 118 | 55 | 9 (W) | |
| S-37-78 | Existing Sulfur Facility | 35 | 17 | 60 (N) | 118 | 55 | 5 (W) | |
| S-37- | Proposed Reformer Facility | 35 | 17 | 63 (N) | 118 | 55 | 14 (W) | |
| S-37- | Proposed Sulfur Facility | 35 | 17 | 70 (N) | 118 | 55 | 12 (W) | |
| S-37-104 | Vacuum Tower | 35 | 17 | 73 (N) | 118 | 55 | 12 (W) | This project was not implemented and expires July 2004. |
| S-37-113 | SRU No. 2 | 35 | 17 | 60 (N) | 118 | 55 | 06 (W) | This project was not implemented and expired in December 2003. |
| S-37-114 | Cogeneration Unit | 35 | 17 | 74 (N) | 118 | 55 | 08 (W) | |
| Residence Receptor | | 35 | 17 | 76 (N) | 118 | 55 | 33 (W) | |
| Business Receptor | | 35 | 17 | 57 (N) | 118 | 54 | 81 (W) | |

**Refinery Overview - Not To Scale**



Attachment No. 10

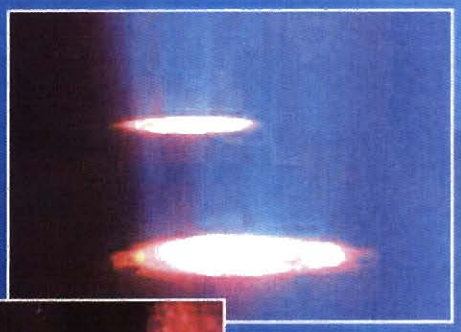
**Check No. 51995 - Application Fee**

Attachment

**District Rule List**

# Project Support Information

# CALLIDUS TECHNOLOGIES



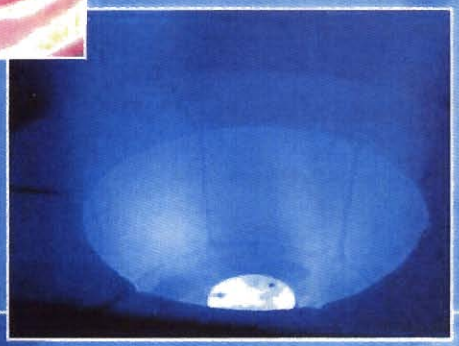
ROUND
FLAME
CUB 8-W



CUBF-4W

## *UltraBlue™ Burner*

***Meeting the Challenge, Setting the Standards***



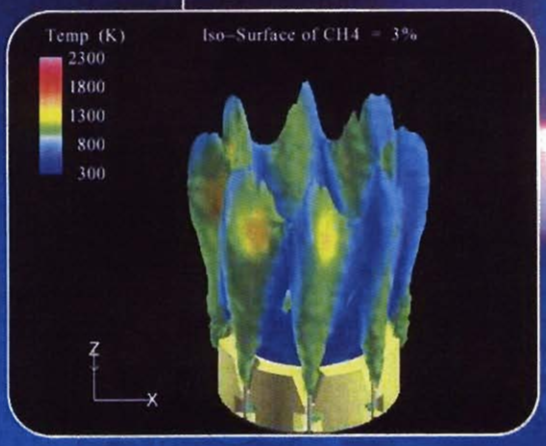
ADVANCED ULTRABLUE™
TECHNOLOGY

CALLIDUS
TECHNOLOGIES, L.L.C.
The Environmental & Combustion Experts.

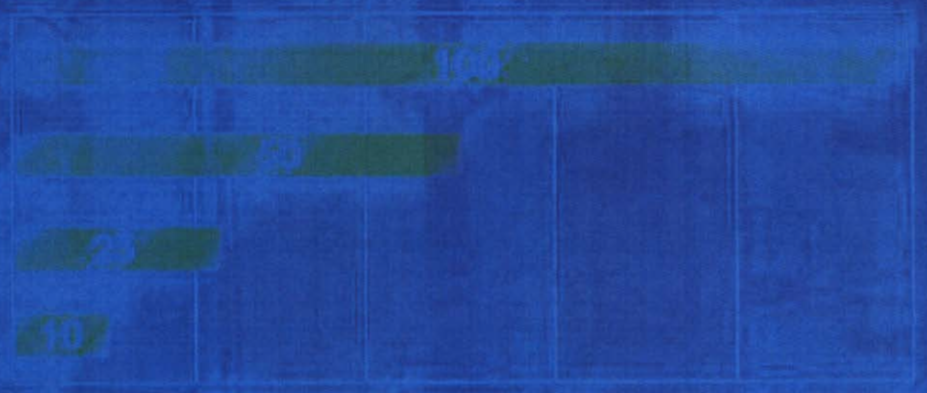
PEXH 000550

## $NO_X$ Reduction

| (100 mg/Nm³) | (50 mg/Nm³) | | (20 mg/Nm³) | |
|---|---|---|---|---|
| 50 ppm | <25 ppm | | <10 ppm | |
| 1989 | 1991 | 1996 | 2000 | 2002 |
| Callidus begins operations | Low emission burners developed by Callidus | Callidus begins UltraBlue™ burner development for ultra low $NO_X$ emissions | First installation of CUB burners | 800th CUB installation |




*Advanced Combustion Modeling*






*The Callidus UltraBlue™ burner was the first process heater burner to achieve <10ppm (20mg/Nm³) $NO_X$.

PEXH 000551

# To Meet Ultra low $NO_X$ emissions - Turn To [Callidus Technologies] And Our Proven UltraBlue™ burners

Innovation and technology have established Callidus among the world leaders in ultra low $NO_X$ burner development. The Callidus burner group has been on the leading edge of burner design for more than a decade. Working in conjunction with our customers, Callidus has developed the Callidus UltraBlue™ (CUB) burner, the first process heater burner to achieve < 10ppm *(20mg/Nm³)** $NO_X$.

With hundreds of installations in operation today, the broad acceptance of the CUB burner has made it the ultra low $NO_X$ burner of choice for many of the industry's leading companies.

### CUB Capabilities and Performance

- Less than 10ppm *(20mg/Nm³)* $NO_X$ achieved in the field with optimum fuel composition and furnace temperatures
- $NO_X$ levels between 10-20ppm *(20-40mg/Nm³)* are typical results in hundreds of CUB burners currently in service
- Eliminates or reduces the need for expensive post-combustion equipment
- Burner is totally self-contained; no external flue gas recirculation or steam injection necessary
- Burner heat releases from 2 to 30MMBtu/hr *(0.5 to 7.6 Gcal/hr)* with higher capacities under development
- Turndown of at least 3:1
- Flame length approximately 1.25'/MMBtu *(1.6m/Gcal)* fired
- Natural and forced draft operation
- Ambient and preheated air
- Round and flat flame designs

### CUB Applications

- Process Heaters for Refining and Petro-Chemical Industries
- Reforming Furnaces
- Cracking Furnaces
- Coking Furnaces

## Meeting $NO_X$ Regulations with the [Callidus UltraBlue™ Retrofit Kit]

$NO_X$ regulations are becoming more stringent each year. To meet the new regulations, Callidus has developed a cost effective upgrade for existing heaters and furnaces. The UltraBlue™ retrofit kit (CUBR) is designed to retrofit existing Callidus low emission (LE) burners in service by reducing $NO_X$ emissions up to 50%. The CUBR Kit can be easily installed during a scheduled routine or major shutdown and requires no special equipment or heavy machinery.

### CUBR Kit includes:

- Tile assembly
- Burner tip/riser assembly
- Updated general arrangement drawings
- Easy to understand change-out procedures
- On-site technical assistance available on request

## Computational Fluid [Dynamic Modeling]

Our in-house Computational Fluid Dynamics (CFD) capabilities were used to create a three-dimensional model showing various CUB designs under different firing conditions. This information and real world experience combined with Fluent® software helped solve the thermodynamic equations required to create a burner with less than 10-ppm *(20mg/Nm³)* $NO_X$. Our CFD models are also used to help assure that our customers' CUB retrofit projects meet their performance expectations. CFD can effectively predict the system efficiencies, reducing production time and avoiding potential installation problems.

**Callidus, Meeting The Challenge - Setting The Standards**

*Burners • Flares • Vapor Control Systems • Rotary Kilns • Thermal Oxidizers • CFD Modeling*

* *Measurements shown in italics are metric conversions.*



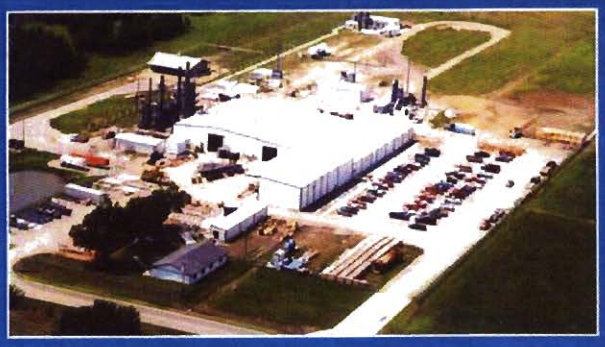
PEXH 000552

## *[Global Installation]* *and Field Service*

Callidus installation and field service teams provide first class service to our customers. Familiarity and experience with Callidus UltraBlue™ burners enable us to provide enhanced product management, efficient turn-a-rounds, start-up assistance and turn-key installations with a high level of quality control.

**Callidus Advantages:**

- Turnkey installation of CUB burners:
  - Demolition of existing equipment
  - Field modifications
  - Floor/wall panel replacements
  - Fuel piping modifications
- Single point responsibility
- Detailed assessment of existing situations
- Project reporting
- Quality control



*Callidus research, development and manufacturing facility*

## *Continuing* *[Research and Development]*

The CUB is a prime example of Callidus leadership in environmental and combustion technology development at our world class R&D facility. The facility includes furnaces dedicated to burner innovation, testing and customer demonstrations.

**Our test facility features:**

- 7 water cooled furnaces vertical cylindrical, box and horizontal heaters
- Custom designed ethylene service testing
- Multiple observation points
- Heat flux profile measurement ports
- Fully instrumented for remote gathering of live test data

## *[Manufacturing]*

Each step of our manufacturing process is consistently reviewed to ensure the highest quality control standards are met and to make sure that our customers expectations are achieved. Callidus CUB Burners are produced at our manufacturing and fabrication facility in Beggs, Oklahoma, USA. Callidus fabrication and manufacturing process are certified ISO 9002

**Home Office:** 7130 South Lewis, Suite 335 • Tulsa*, OK 74136
Phone: 1-918-496-7599 • FAX: 1-918-496-7587 • **Web site: www.callidus.com**
Sales offices worldwide.

**Callidus Japan**
Phone: +81-(0)44-850-8209
FAX: +81-(0)44-850-8217

**Callidus U.K.**
Phone: +44(0)1438 747550
FAX: +44(0)1438 747551

CALLIDUS TECHNOLOGIES, L.L.C.
The Environmental & Combustion Experts.

***"Meeting The Challenge, Setting The Standards"***

CB&I

Callidus Technologies, L.L.C. is a wholly owned subsidiary of Chicago Bridge & Iron Company N.V. CB&I is a global specialty engineering fabrication and construction company focused on turnkey, design-built solutions for the hydrocarbon industry.

REGISTERED COMPANY ISO 9002 SGS *

# Section I: AQMD BACT Determinations

## Application No.: 352869

## Equipment Category - Heater - Refinery

### 1. GENERAL INFORMATION

DATE: 1/3/2001

A. MANUFACTURER: Tulsa Heaters Inc.

B. TYPE: Horizontal Cabin

C. MODEL:

D. STYLE:

E. APPLICABLE AQMD REGULATION XI RULES: None (This facility is a RECLAIM facility. All previously applicable Regulation XI rules have been supplanted by RECLAIM rules - See AQMD Regulation XX - RECLAIM)

F. COST: $500,000 (1999) SOURCE OF COST DATA: Owner/Operator

G. OPERATING SCHEDULE: 24 HRS/DAY 7 DAYS/WK 52 WKS/YR

### 2. EQUIPMENT INFORMATION

APP. NO.: 352869

A. FUNCTION: This is a new coker charge heater for a delayed coking unit at the refinery.

B. MAXIMUM HEAT INPUT: 50

C. MAXIMUM THROUGHPUT: MMBtu/hr

D. BURNER INFORMATION: NO.: 8 TYPE: John Zink Low NOx

E. PRIMARY FUEL: Natural Gas

F. OTHER FUEL: NONE

G. OPERATING CONDITIONS: Variable Load

### 3. COMPANY INFORMATION

APP. NO.: 352869

A. NAME: CENCO Refining Company

B. ADDRESS: 12345 Lakeland Road
CITY: Santa Fe Springs STATE: CA ZIP: 90670

C. CONTACT PERSON: June Christman

D. PHONE NO.: 562-906-2913

### 4. PERMIT INFORMATION

APP. NO.: 352869

A. AGENCY: `SCAQMD

B. APPLICATION TYPE: new construction

C. AGENCY CONTACT PERSON: Emmanuel R. Ruivivar

D. PHONE NO.: 909-396-2509

E. PERMIT TO CONSTRUCT INFORMATION: P/C NO.: 352869 ISSUANCE DATE: 11/17/2000
☐ CHECK IF NO P/C

F. START-UP DATE: One year upon receiving financing to resume crude oil refining.

G. PERMIT TO OPERATE INFORMATION: P/O NO.: ISSUANCE DATE:

### 5. EMISSION INFORMATION

APP. NO.: 352869

**A. PERMIT**

A1. PERMIT LIMIT: NOx - 5 ppmvd @3% O2, 3-hr ave ; CO - 10 ppmv @3% O2, 1-hr ave. ; NH3 - 9 ppmvd @3%O2, 1-hr ave.

## 5. EMISSION INFORMATION

APP. NO.: 352869

A2. BACT/LAER DETERMINATION: The above permit limits are based on the following:

For NOx - [AN368005, 82.8 MMBtu/Hr Refinery Heater, Chevron Products, P/C 9/1/2000; AN368005]

For NH3 - [AN 368005, see above]

For CO - [AN337979, 764 MMBtu/Hr Refinery Heater, Air Products, P/C 9/11/1998]

### B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Technip USA

B2. TYPE: Selective Catalytic Reduction (SCR)

B3. DESCRIPTION: The proposed refinery heater will be provided with low NOx burners to reduce NOx emissions to about 30 ppmv in the exhaust gas before it goes to SCR. In the SCR system, ammonia is injected into the flue gas in the presence of a catalyst. The ammonia selectively reacts with NOx to form molecular nitrogen and water. This reaction takes place in the temperature range of approximately 315-400 deg. C. Injection of ammonia from an aqueous solution will be controlled to achieve the desired NOx outlet and slip ammonia.

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: 352870 ISSUANCE DATE:
P/O NO.: ISSUANCE DATE:

B5. WASTE AIR FLOW TO CONTROL EQUIPMENT: FLOW RATE: 685,107 scfh
ACTUAL CONTAMINANT LOADING: 30 ppmv NOx BLOWER HP: HP

B6. WARRANTY: Three(3) years

B7. PRIMARY POLLUTANTS: VOC, NOx, CO, SOx AND PM10

B8. SECONDARY POLLUTANTS: NH3

B9. SPACE REQUIREMENT: SCR Reactor: 7.5 ' W. x 3.63' L. x 2.8' H.

B10. LIMITATIONS: none

B11. LOCATION OF PRIOR DEMONSTRATION & AGENCY:
FACILITY:
CONTACT PERSON: PHONE NO.:
AGENCY: SCAQMD
ADDRESS:
CONTACT PERSON: PHONE NO.:

B12. OPERATING HISTORY: Heater/SCR not yet installed.

B13. SOURCE TEST/PERFORMANCE DATA ANALYSIS:
DATE OF SOURCE TEST: CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICEINCY:
PERFORMANCE DATA:

B14. SOURCE TEST CONDITIONS/PERFORMANCE DATA:

### C. COST

C1. CONTROL EQUIPMENT COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN CAPITAL COST
CAPITAL: $550,000 INSTALLATION: $338,000 (1999) SOURCE OF COST DATA: Owner/Operator

C2. ANNUAL OPERATIONAL/MAINTENANCE COST: $50,000 (1999) SOURCE OF COST DATA: Owner/Operator

## 5. EMISSION INFORMATION

APP. NO.: 352869

### D. DEMONSTRATION OF COMPLIANCE

| | | | | |
|---|---|---|---|---|
| D1. | STAFF PERMFORMING FIELD EVALUATION: | | | |
| | ENGINEER'S NAME: | INSPECTOR'S NAME: | | DATE: |
| D2. | COMPLIANCE DEMONSTRATION: | | | |
| D3. | VARIANCE: | NO. OF VARIANCES: | DATES: | |
| | CAUSES: | | | |
| D4. | VIOLATION: | NO. OF VIOLATIONS: | DATES: | |
| | CAUSES: | | | |
| D5. | FREQUENCY OF MAINTENANCE: | | | |

## 6. COMMENTS

APP. NO.: 352869

Only natural gas fuel will be used in the heater to comply with BACT for SOx. Hitachi Zosen NOxNON catalyst will be used in the SCR system. RECLAIM CEMS will be provided for the equipment. Source tests will be required to verify compliance with the emission limits.

# Section I: AQMD BACT Determinations

## Application No.: 371784

## Equipment Category – Process Heater - Non-Refinery

### 1. GENERAL INFORMATION

DATE: 11/7/2002

| | | | |
|---|---|---|---|
| A. | MANUFACTURER: American Hydrotherm | | |
| B. | TYPE: Forced Circulation | C. MODEL: 1200-4D-90 | |
| D. | STYLE: Horizontal Double-Pipe Coil | | |
| E. | APPLICABLE AQMD REGULATION XI RULES: 1146 | | |
| F. | COST: $ (2000) | SOURCE OF COST DATA: | |
| G. | OPERATING SCHEDULE: 24 HRS/DAY | 7 DAYS/WK | 52 WKS/YR |

### 2. EQUIPMENT INFORMATION

APP. NO.: 371784

| | | | |
|---|---|---|---|
| A. | FUNCTION: Heats recirculating oil used in laminating presses. | | |
| B. | MAXIMUM HEAT INPUT: 19 MMBtu/hr | C. MAXIMUM THROUGHPUT: | |
| D. | BURNER INFORMATION: NO.: 1 | TYPE: Ultra Low-NOx | |
| E. | PRIMARY FUEL: Natural Gas | F. OTHER FUEL: NONE | |
| G. | OPERATING CONDITIONS: Average firing rate = 60% | | |

### 3. COMPANY INFORMATION

APP. NO.: 371784

| | | | |
|---|---|---|---|
| A. | NAME: NELCO Products, Inc. | B. SIC CODE: 3672 | |
| C. | ADDRESS: 1411 E. Orangethorpe Ave.<br>CITY: Fullerton | STATE: CA | ZIP: 92831 |
| D. | CONTACT PERSON: Jennifer Sanchez | E. PHONE NO.: 714-879-4293 | |

### 4. PERMIT INFORMATION

APP. NO.: 371784

| | | | |
|---|---|---|---|
| A. | AGENCY: SCAQMD | B. APPLICATION TYPE: new construction | |
| C. | AGENCY CONTACT PERSON: Rick Lee | D. PHONE NO.: 909-396-2629 | |
| E. | PERMIT TO CONSTRUCT/OPERATE INFORMATION: | P/C NO.: 371784 | ISSUANCE DATE: 8/4/2000 |
| | ☐ CHECK IF NO P/C | P/O NO.: 371784 | ISSUANCE DATE: 12/5/2001 |
| F. | START-UP DATE: 2/1/01 (Approx.) | | |

### 5. EMISSION INFORMATION

APP. NO.: 371784

| | | |
|---|---|---|
| **A.** | **PERMIT** | |
| A1. | PERMIT LIMIT: 12 ppmd NOx (3% O2), 50 ppmd CO (3% O2), Natural Gas Only | |
| A2. | BACT/LAER DETERMINATION: Same as 5-A1 | |
| A3. | BASIS OF THE BACT/LAER DETERMINATION: Suggested by Applicant | |
| **B.** | **CONTROL TECHNOLOGY** | |
| B1. | MANUFACTURER/SUPPLIER: Alzeta Corp. | |

## 5. EMISSION INFORMATION

APP. NO.: 371784

B2. TYPE: Ultra Low-NOx Burner (ULNB)

B3. DESCRIPTION: Model CSB-22-250-30/15 pre-mixed, porous-surface burner. Dimensions: 22" D x 45" L. Turndown: 4:1. Operates at 70% excess air at full load (5090 scfm). Pressure drop at full load is 4-6" w.g.. 25 hp blower required.

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: ISSUANCE DATE:
P/O NO.: ISSUANCE DATE:

B5. WASTE AIR FLOW TO CONTROL EQUIPMENT: FLOW RATE:
ACTUAL CONTAMINANT LOADING: BLOWER HP:

B6. WARRANTY: 12 ppm NOx and 50 ppm CO were guaranteed by American Hydrotherm. 9 ppm NOx and 50 ppm CO were guaranteed by Alzeta. All guaranteed ppm were dry basis, corrected to 3% O2.

B7. PRIMARY POLLUTANTS: NOx, CO, NMHC, PM, SOx

B8. SECONDARY POLLUTANTS: None

B9. SPACE REQUIREMENT:

B10. LIMITATIONS: B11. UNUSED

B12. OPERATING HISTORY: Has been in regular use since startup. Facility contact person believes the heater may have started up before the expected Feb 2001 date.

B13. UNUSED B14. UNUSED

## C. CONTROL EQUIPMENT COSTS

C1. CAPITAL COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN EQUIPMENT COST
EQUIPMENT: $ INSTALLATION: $ (2000) SOURCE OF COST DATA:

C2. ANNUAL OPERATING COST: $ (2000) SOURCE OF COST DATA:

## D. DEMONSTRATION OF COMPLIANCE

D1. STAFF PERMFORMING FIELD EVALUATION:
ENGINEER'S NAME: INSPECTOR'S NAME: Lily Henry DATE: 10/23/2001

D2. COMPLIANCE DEMONSTRATION:

D3. VARIANCE: NO. OF VARIANCES: None DATES:
CAUSES:

D4. VIOLATION: NO. OF VIOLATIONS: None DATES:
CAUSES:

D5. MAINTENANCE REQUIREMENTS: D6. UNUSED

## 5. EMISSION INFORMATION

APP. NO.: 371784

D7. SOURCE TEST/PERFORMANCE DATA RESULTS AND ANALYSIS:

DATE OF SOURCE TEST: 3/27/2001

CAPTURE EFFICIENCY:

DESTRUCTION EFFICIENCY:

OVERALL EFFICEINCY:

| Test Condition | Low Fire | High Fire |
|---|---|---|
| Heat Input, MMBtu/hr | 5.1 | 15.3 |
| O2, % (dry) | 8.8 | 9.2 |
| NOx, ppm (dry, 3% O2) | 4.5 | 3.3 |
| CO, ppm (dry, 3% O2) | <1 | <1 |

Source test accepted by AQMD Monitoring & Source Test Engineering group.

SOURCE TEST/PERFORMANCE DATA:

OPERATING CONDITIONS: High and low firing rates

TEST METHODS: AQMD Method 100.1

## 6. COMMENTS

APP. NO.: 371784

American Hydrotherm is no longer in business. However, Alzeta still offers this burner for horizontal double-coil heaters (e.g., American Heater Co.).

# Section I: AQMD BACT Determinations

## Application No.: 347641

## Equipment Category – Heater - Other Process

### 1. GENERAL INFORMATION

DATE: 11/20/2002

A. MANUFACTURER: American Heater Co.

B. TYPE: Hot oil heater

C. MODEL: AHE-650

D. STYLE: Horizontal double pipe coil

E. APPLICABLE AQMD REGULATION XI RULES: 1146

F. COST: $73,000 (1999) SOURCE OF COST DATA: Owner/Operator

G. OPERATING SCHEDULE: 24 HRS/DAY 7 DAYS/WK 22 WKS/YR

### 2. EQUIPMENT INFORMATION

APP. NO.: 347641

A. FUNCTION: Heater No. 416. Used to regenerate liquid absorbent (triethylene glycol) by heating it to approximately 450 degrees Fahrenheit to remove absorbed water.

B. MAXIMUM HEAT INPUT: 6.5 MMbtu/hr

C. MAXIMUM THROUGHPUT:

D. BURNER INFORMATION: NO.: one TYPE: Power Flame low-NOx burner

E. PRIMARY FUEL: Natural Gas

F. OTHER FUEL: NONE

G. OPERATING CONDITIONS: Variable

### 3. COMPANY INFORMATION

APP. NO.: 347641

A. NAME: Southern California Gas Company

B. ADDRESS: 12801Tampa Avenue
CITY: Northridge STATE: CA ZIP: 91326

C. CONTACT PERSON: John Clark

D. PHONE NO.: (818) 700-3812

### 4. PERMIT INFORMATION

APP. NO.: 347641

A. AGENCY: SCAQMD

B. APPLICATION TYPE: new construction

C. AGENCY CONTACT PERSON: Henrique Nascimento

D. PHONE NO.: (909) 396-2519

E. PERMIT TO CONSTRUCT INFORMATION: P/C NO.: 347641 ISSUANCE DATE: 8/17/1999
☐ CHECK IF NO P/C

F. START-UP DATE: August 1999

G. PERMIT TO OPERATE INFORMATION: P/O NO.: pending ISSUANCE DATE:

### 5. EMISSION INFORMATION

APP. NO.: 347641

**A. PERMIT**

A1. PERMIT LIMIT: NOx =< 20 ppmvd @ 3% O2, CO =< 50 ppmvd @ 3% O2

A2. BACT/LAER DETERMINATION: Compliance with the above permit limits.

## 5. EMISSION INFORMATION

APP. NO.: 347641

### B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Power Flame

B2. TYPE: Model C5-G-30B

B3. DESCRIPTION: Low-NOx burner with flue gas recirculation

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: ISSUANCE DATE:
P/O NO.: ISSUANCE DATE:

B5. WASTE AIR FLOW TO CONTROL EQUIPMENT: FLOW RATE: N/A
ACTUAL CONTAMINANT LOADING: N/A BLOWER HP: N/A HP

B6. WARRANTY: Will meet emission limits for 1-year.

B7. PRIMARY POLLUTANTS: NOx, CO, ROG, PM10, and SOx

B8. SECONDARY POLLUTANTS: None

B9. SPACE REQUIREMENT: N/A

B10. LIMITATIONS:

B11. LOCATION OF PRIOR DEMONSTRATION & AGENCY:
FACILITY: None at 6.5 MMbtu/hour rating
CONTACT PERSON: PHONE NO.:
AGENCY:
ADDRESS:
CONTACT PERSON: PHONE NO.:

B12. OPERATING HISTORY: These three heaters have operated satisfactorilly under widely varying load conditions since their startups.

B13. SOURCE TEST/PERFORMANCE DATA ANALYSIS:
DATE OF SOURCE TEST: 6/22/2000 CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICEINCY:
PERFORMANCE DATA:

| Test Date | June 22, 2000 | | | September 21, 2000 | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Heater No. | 416 | | | 417 | | | 418 | | |
| Test Condition | High | Mid | Low | High | Mid | Low | High | Mid | Low |
| Load, % | 99.4 | 87.7 | 47.7 | 96.8 | 88.1 | 38.7 | 94 | 87 | 28 |
| Input, MMBtu/hr | 6.5 | 5.7 | 3.1 | 6.3 | 5.7 | 2.5 | 6.1 | 5.7 | 1.8 |
| FGR setting, % | 80 | 50 | 20 | 50 | 75 | 20 | 90 | 50 | 20 |
| O2, % (dry) | 4.6 | 4.3 | 4.0 | 3.3 | 2.0 | 2.0 | 1.86 | 1.86 | 4.95 |
| NOx, ppm (dry @ 3% O2) | 19.1 | 19.8 | 19.6 | 20.1 | 16.5 | 17.1 | 17.5 | 19.5 | 19.2 |
| CO, ppm (dry @ 3% O2) | <22 | <22 | <21 | <20 | <19 | <19 | <19 | <19 | <22 |

Source test accepted by AQMD Monitoring & Source Test Engineering group

B14. SOURCE TEST CONDITIONS/PERFORMANCE DATA:

### C. COST

C1. CONTROL EQUIPMENT COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN CAPITAL COST
CAPITAL: $ INSTALLATION: $ ( ) SOURCE OF COST DATA:

## 5. EMISSION INFORMATION

APP. NO.: 347641

C2. ANNUAL OPERATIONAL/MAINTENANCE COST: $ ( ) SOURCE OF COST DATA:

## D. DEMONSTRATION OF COMPLIANCE

D1. STAFF PERMFORMING FIELD EVALUATION:

ENGINEER'S NAME: INSPECTOR'S NAME: DATE:

D2. COMPLIANCE DEMONSTRATION:

D3. VARIANCE: NO. OF VARIANCES: None DATES:

CAUSES:

D4. VIOLATION: NO. OF VIOLATIONS: None DATES:

CAUSES:

D5. FREQUENCY OF MAINTENANCE:

## 6. COMMENTS

APP. NO.: 347641

The manufacturer of the heater provided the District with a written guarantee that the unit will achieve the specified permit limits (i.e., NOx less than or equal to 20 ppmvd and CO less than or equal to 50 ppmvd). Along with this application, the applicant submitted two additional applications (A/Ns 347643 and 347644) for identical equipment (used for the same purpose) at the same location.

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
# *Best Available Control Technology (BACT) Guideline*

## *Source Category*

| | | | |
|---|---|---|---|
| Source: | ***Heater - Refinery Process, Natural or Induced Draft*** | Revision: | *3* |
| | | Document #: | *94.1.1* |
| Class: | ***5 MMBtu/hr to <50 MMBtu/hr Heat Input*** | Date: | *08/12/94* |

## *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *n/s* | 1. *n/d*<br>2. *Good Combustion Practice*[a] |
| NOx | 1. *10 ppmv @ 3% $O_2$ Dry*[a,b,c,e]<br>2. *25 ppmv @ 3% $O_2$ Dry*[a,b,e] | 1. *Selective Catalytic Reduction (SCR) + Low $NO_x$ Burners*[a,b,c]<br>2. *Low $NO_x$ Burners; or Low $NO_x$ Burners + Selective Non-Catalytic Reduction (SNCR)*[a,d] |
| $SO_2$ | 1. *Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur*[a]<br>2. *Natural Gas or Treated Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur*[a] | 1. *Fuel Selection*[a]<br>2. *Fuel Selection*[a] |
| CO | 1. *n/d*<br>2. *50 ppmv @ 3% $O_2$ Dry*[a,f] | 1. *n/d*<br>2. *Good Combustion Practice*[a] |
| $PM_{10}$ | 1. *n/d*<br>2. *Natural Gas or Treated Refinery Gas Fuel*[a,b] | 1. *n/d*<br>2. *Fuel Selection*[a,b] |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

## *References*

*a. BAAQMD*
*b. BAAQMD A #30783*
*c. BAAQMD A #3318*
*d. BAAQMD A #8407*
*e. $NO_x$ determination by BAAQMD Source Test Method ST-13A or B (average of three 30-minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.*
*f. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD*

*approved equivalent.*

# COOL*star*™ Burner

## The Industry's Most Compact Ultra Low-NOx Gas Burner

John Zink Company, the world leader in advanced clean-air solutions and technologies, introduces its COOL*star* burner, the industry's most compact, ultra low-NOx burner.

The patent-pending COOL*star* burner employs a new proprietary flue-gas entrainment and mixing strategy using the potential energy of incoming fuel and air streams. The result? Stable, compact flames with single-digit NOx.

The engineers at Zink® developed the COOL*star* burner from the customer's point of view with a focus on safety, ease of operation and optimum performance. Its compact design fits the furnace cutouts of conventional burners with little to no modifications. The COOL*star* burner requires minimal maintenance and operates with a range of fuels, setting a new standard for economical, ultra low-NOx combustion.

To learn more about the COOL*star* burner, call the clean combustion experts at John Zink Company.

| Americas | Asia-Pacific | Europe |
|---|---|---|
| +1-918-234-1800 | +81-3-5435-8551 | +352-518991 |
| +1-800-421-9242 | +65-6732-7555 | +44-1932-769830 |
| | +61-2-8833-4600 | +39-02-6698-1232 |
| | | +33-1-4119-4100 |

| JZ Burner | Predicted NOx (ppm) | Heater Cutout (in.) | Tile O.D. (in.) |
|---|---|---|---|
| PVYD-17RM | 163 | 18.5 | 24.5 |
| PSFG-16RM | 50 | 18.5 | 24.25 |
| PQMR-17RM | 15 | 31.5 | 30.5 |
| COOL*star*-315 | 8 | 15.5 | 24.25 |

- Predicted NOx: single burner test furnace for comparison basis
- Fuel: 50% natural gas; 25% propane; 25% hydrogen
- Furnace temperature: 1,600 °F
- Draft: 0.3 in.
- Heat release: 8 MM Btu/hr

## COOL*star* Burner Features

- **Ultra low-NOx**
  - Reduces emissions by as much as 90%
  - Delivers single digit (ppm) NOx in some refinery conditions
- **Compact size**
  - Installs into existing burner opening
  - Innovative axial damper reduces space required around burner plenum
- **Ease of operation**
  - Provides stable cold-furnace start-up
  - Features single fuel gas connection
  - Features single air control
- **Low maintenance**
  - Eliminates metal flame holder
  - Fewer tips and larger orifices than other burners in its class
  - Tips positioned in furnace floor for protection from heat
- **Short, stable flame**
  - Exhibits short visible flame (as low as 1.5 ft/MM Btu)
- **Wide-range of fuels**
  - Natural gas through refinery fuel containing $H_2$ and other components
- **High turndown**
  - 4:1 and higher turndown

The COOL*star*™ burner has patent pending in the USA.

JOHN ZINK
JOHN ZINK COMPANY LLC

11920 East Apache, Tulsa, OK 74116 www.johnzink.com

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www.johnzink.com Think Zink®

# BACT Clearinghouse Search Results

5 matching record(s) found

District - All Districts
Category - Heater: Refinery Process, Natural or Induced Draft < 50 MMBtu/hr
Pollutant - All

| Capacity / Dimention | Pollutant | District Name<br>District Contact | Plant Name | |
|---|---|---|---|---|
| 16 MMBtu/hr | NOx, CO, VOC, SOx | Santa Barbara County APCD<br>Mike Goldman | Torch Operating Co. (Lompc Oil and Gas Plant) | View Determination |
| 16 MMBtu/hr | NOx, | Santa Barbara County APCD<br>Michael Goldman | Unocal Corp. (Pt. Pedernales Project) | View Determination |
| 6 MMBtu/hr | NOx, | San Joaquin Valley APCD<br>Tom Goff | Macpherson Oil Company | View Determination |
| 2.36 MMBtu/hr | NOx, CO, VOC, SOx | Santa Barbara County APCD<br>Bil Master | Chevron - Gaviota | View Determination |
| 8.4 to 47.1 MMBtu/hr | NOx, VOC, PM 10, | San Joaquin Valley APCD<br>George Heinen | San Joaquin Refining Company Inc. | View Determination |

# BACT Determination Detail

## Category

| | |
|---|---|
| *Source Category:* | Heater: Refinery Process, Natural or Induced Draft < 50 MMBtu/hr |
| *SIC Code* | 99 |
| *NAICS Code* | |

## Emission Unit Informaiton

| | |
|---|---|
| *Manufacturer:* | |
| *Type:* | |
| *Model:* | |
| *Equipment Description:* | Three oil-emulsion treaters |
| *Capacity / Dimentions* | 16 MMBtu/hr |
| *Fuel Type* | Propane |
| *Multiple Fuel Types* | |
| *Operating Schedule (hours/day)/(days/week)/ (weeks/year)e* | Variable ( / / ) |
| *Function of Equipment* | |

## Bact Information

| | |
|---|---|
| *NOx Limit* | 22 |
| *NOx Limit Units* | ppmvd @ 3% O2 |
| *NOx Average Time* | |
| *NOx Control Method* | |
| *NOx Control Method Desc* | Alzeta low NOx burner |

| | |
|---|---|
| *CO Limit* | 25 |
| *CO Limit Units* | ppmvd @ 3% O2 |
| *CO Average Time* | |
| *CO Control Method* | |
| *CO Control Method Desc* | Alzeta low NOx burner |

| | |
|---|---|
| *VOC Limit* | 4 |
| *VOC Limit Units* | ppmvd @ 3% O2 |
| *VOC Average Time* | |
| *VOC Control Method* | |
| *VOC Control Method Desc* | Alzeta low NOx burner |

| | |
|---|---|
| *SOx Limit* | 0.011 |
| *SOx Limit Units* | lbm/MMBtu |

| | |
|---|---|
| *SOx Average Time* | |
| *SOx Control Method* | |
| *SOx Control Method Desc* | Alzeta low NOx burner |

## Project / Permit Information

| | |
|---|---|
| *Application/Permit No.:* | 9522 |
| *New Construction/Modification:* | New Construction |
| *ATC Date:* | |
| *PTO Date:* | |
| *Startup Date:* | |
| *Technology Status:* | BACT Determination |
| *Source Test Available:* | Yes |
| *Source Test Results:* | |

## Facility / District Information

| | |
|---|---|
| *Facility Name:* | Torch Operating Co. (Lompc Oil and Gas Plant) |
| *Facility Zip Code:* | |
| *Facility County:* | |
| *District Name:* | Santa Barbara County APCD |
| *District Contact:* | Mike Goldman |
| *Contact Phone No.:* | (805) 961-8821 |
| *Contact E-Mail:* | goldmanm@sbcapcd.org |

## Notes

| | |
|---|---|
| *Notes:* | |

Report Error In Determination

# BACT Determination Detail

## Category

| | |
|---|---|
| *Source Category:* | Heater: Refinery Process, Natural or Induced Draft < 50 MMBtu/hr |
| *SIC Code* | 99 |
| *NAICS Code* | |

## Emission Unit Informaiton

| | |
|---|---|
| *Manufacturer:* | |
| *Type:* | |
| *Model:* | |
| *Equipment Description:* | Three heater treaters |
| *Capacity / Dimentions* | 16 MMBtu/hr |
| *Fuel Type* | Other |
| *Multiple Fuel Types* | |
| *Operating Schedule (hours/day)/(days/week)/ (weeks/year)e* | Variable ( / / ) |
| *Function of Equipment* | |

## Bact Information

| | |
|---|---|
| *NOx Limit* | 22 |
| *NOx Limit Units* | ppmd @ 3% O2 |
| *NOx Average Time* | |
| *NOx Control Method* | |
| *NOx Control Method Desc* | Alzeta pyrocore low NOx ceramic fiber radiant burners |

## Project / Permit Information

| | |
|---|---|
| *Application/Permit No.:* | 8696 |
| *New Construction/Modification:* | New Construction |
| *ATC Date:* | |
| *PTO Date:* | |
| *Startup Date:* | |
| *Technology Status:* | BACT Determination |
| *Source Test Available:* | Yes |
| *Source Test Results:* | |

## Facility / District Information

| | |
|---|---|
| *Facility Name:* | Unocal Corp. (Pt. Pedernales Project) |
| *Facility Zip Code:* | |
| *Facility County:* | |
| *District Name:* | Santa Barbara County APCD |
| *District Contact:* | Michael Goldman |
| *Contact Phone No.:* | (805) 961-8821 |
| *Contact E-Mail:* | goldmanm@sbcapcd.org |

## Notes

| | |
|---|---|
| *Notes:* | |

Report Error In Determination

# BACT Determination Detail

## Category

| | |
|---|---|
| *Source Category:* | Heater: Refinery Process, Natural or Induced Draft < 50 MMBtu/hr |
| *SIC Code* | 99 |
| *NAICS Code* | |

## Emission Unit Informaiton

| | |
|---|---|
| *Manufacturer:* | C.E. Natco |
| *Type:* | |
| *Model:* | |
| *Equipment Description:* | heater treater |
| *Capacity / Dimentions* | 6 MMBtu/hr |
| *Fuel Type* | Natural Gas |
| *Multiple Fuel Types* | |
| *Operating Schedule (hours/day)/(days/week)/ (weeks/year)e* | Variable ( / / ) |
| *Function of Equipment* | |

## Bact Information

| | |
|---|---|
| *NOx Limit* | 0.048 |
| *NOx Limit Units* | lbm/MMBtu |
| *NOx Average Time* | |
| *NOx Control Method* | |
| *NOx Control Method Desc* | N. American Lo-NOx burner with flue gas recirculation |

## Project / Permit Information

| | |
|---|---|
| *Application/Permit No.:* | 4126060 |
| *New Construction/Modification:* | New Construction |
| *ATC Date:* | |
| *PTO Date:* | |
| *Startup Date:* | |
| *Technology Status:* | BACT Determination |
| *Source Test Available:* | Yes |
| *Source Test Results:* | |

## Facility / District Information

| | |
|---|---|
| *Facility Name:* | Macpherson Oil Company |
| *Facility Zip Code:* | |
| *Facility County:* | |
| *District Name:* | San Joaquin Valley APCD |
| *District Contact:* | Tom Goff |
| *Contact Phone No.:* | (805) 862-5200 |
| *Contact E-Mail:* | |

## Notes

| | |
|---|---|
| *Notes:* | |

Report Error In Determination

# BACT Determination Detail

## Category

| | |
|---|---|
| *Source Category:* | Heater: Refinery Process, Natural or Induced Draft < 50 MMBtu/hr |
| *SIC Code* | 99 |
| *NAICS Code* | |

## Emission Unit Informaiton

| | |
|---|---|
| *Manufacturer:* | |
| *Type:* | |
| *Model:* | |
| *Equipment Description:* | Four hot oil heaters |
| *Capacity / Dimentions* | 2.36 MMBtu/hr |
| *Fuel Type* | Natural Gas |
| *Multiple Fuel Types* | |
| *Operating Schedule (hours/day)/(days/week)/ (weeks/year)e* | Variable ( / / ) |
| *Function of Equipment* | |

## Bact Information

| | |
|---|---|
| *NOx Limit* | 1.42 |
| *NOx Limit Units* | lbm/hr total |
| *NOx Average Time* | |
| *NOx Control Method* | |
| *NOx Control Method Desc* | Low NOx burner, low excess air |

| | |
|---|---|
| *CO Limit* | 0.57 |
| *CO Limit Units* | lbm/hr total |
| *CO Average Time* | |
| *CO Control Method* | |
| *CO Control Method Desc* | Pipeline quality gas as fuel, proper burner operation |

| | |
|---|---|
| *VOC Limit* | 0.05 |
| *VOC Limit Units* | lbm/hr total |
| *VOC Average Time* | |
| *VOC Control Method* | |
| *VOC Control Method Desc* | Pipeline quality gas as fuel, proper burner operation |

| | |
|---|---|
| *SOx Limit* | 0.01 |
| *SOx Limit Units* | lbm/hr total |

| | |
|---|---|
| *SOx Average Time* | |
| *SOx Control Method* | |
| *SOx Control Method Desc* | Pipeline quality gas as fuel, 4 ppmv H2S max. |

## Project / Permit Information

| | |
|---|---|
| *Application/Permit No.:* | 5704 |
| *New Construction/Modification:* | New Construction |
| *ATC Date:* | |
| *PTO Date:* | |
| *Startup Date:* | |
| *Technology Status:* | BACT Determination |
| *Source Test Available:* | Yes |
| *Source Test Results:* | |

## Facility / District Information

| | |
|---|---|
| *Facility Name:* | Chevron -Gaviota |
| *Facility Zip Code:* | |
| *Facility County:* | |
| *District Name:* | Santa Barbara County APCD |
| *District Contact:* | Bil Master |
| *Contact Phone No.:* | (805) 961-8800 |
| *Contact E-Mail:* | |

## Notes

| | |
|---|---|
| *Notes:* | |

Report Error In Determination

# BACT Determination Detail

## Category

| | |
|---|---|
| *Source Category:* | Heater: Refinery Process, Forced Draft < 50 MMBtu/hr |
| *SIC Code* | |
| *NAICS Code* | 323 |

## Emission Unit Informaiton

| | |
|---|---|
| *Manufacturer:* | American Hydrotherm |
| *Type:* | Forced circulation |
| *Model:* | 1200-4D-90 |
| *Equipment Description:* | |
| *Capacity / Dimentions* | 19 MMBtu/hr |
| *Fuel Type* | Natural Gas |
| *Multiple Fuel Types* | |
| *Operating Schedule (hours/day)/(days/week)/ (weeks/year)e* | Variable (24/7/52) |
| *Function of Equipment* | Heats recirculating oil used in laminating presses |

## Bact Information

| | |
|---|---|
| *NOx Limit* | 12 |
| *NOx Limit Units* | ppmvd 3% O2 |
| *NOx Average Time* | |
| *NOx Control Method* | |
| *NOx Control Method Desc* | Ultra-Low NOx burner-Alzeta Corp. |

| | |
|---|---|
| *CO Limit* | 50 |
| *CO Limit Units* | ppmvd 3% O2 |
| *CO Average Time* | |
| *CO Control Method* | |
| *CO Control Method Desc* | |

## Project / Permit Information

| | |
|---|---|
| *Application/Permit No.:* | 371784 |
| *New Construction/Modification:* | New Construction |
| *ATC Date:* | 08-04-2000 |
| *PTO Date:* | |
| *Startup Date:* | 02-01-2001 |

| | |
|---|---|
| *Technology Status:* | BACT Determination |
| *Source Test Available:* | No |
| *Source Test Results:* | |

## Facility / District Information

| | |
|---|---|
| *Facility Name:* | NELCO Products. Inc, |
| *Facility Zip Code:* | 92831 |
| *Facility County:* | Orange |
| *District Name:* | South Coast AQMD |
| *District Contact:* | Martin Kay |
| *Contact Phone No.:* | 909-396-3115 |
| *Contact E-Mail:* | mkay@aqmd.gov |

## Notes

| | |
|---|---|
| *Notes:* | The applicant proposed to use the Alzeta ULNB. Although the model CBS burner has not been demonstrated in a process heater, it has been successfully demonstrated in a variety of water-tube and fired-tube boilers. While this application has not yet been source tested, It is highly probable that it will prove successful and will become achieved-in-practice technology for small process heaters of this type. The level was suggested by the applicant. |

Report Error In Determination

VII. CALCULATIONS (Continued):

The fugitive emissions are based on the best available control technology (BACT) requirement of a 100 ppm maximum emission rate for valve/flange VOC emissions, and a 500 ppm maximum emission rate for pumps/compressor VOC emissions. These emission levels were established as BACT for this class of source by project 2007 - 920825 (Texaco R&M). For valves/flanges the emission concentration of 100 ppm is 1% of 10,000 ppm; therefore the BACT requirement provides a 99% control efficiency. For pump/compressors seals the emission concentration of 500 ppm is 5% of 10,000 ppm; therefore, the BACT requirements provides a 95% control efficiency. The 99% and 95% control efficiencies are used in the calculations on page 12.

The emissions from the heaters are based on District recognized (AP-42, 10/92) emission factors and applicant proposed emission factors. To satisfy BACT requirements for $NO_x$, the new gas fired emissions units are proposed to operate at a minimum of 30 ppm @ 3% $O_2$. All the new fired equipment is associated with the hydrotreater unit.

Aside from the increases associated with the increased number of components and the fired equipment, there are also emission reductions associated with the proposed modification to the facility. The facility currently uses a fuel gas (generated at the refinery) to fuel fired equipment. The addition of the sulfur recovery unit allows the fuel gas stream to be treated for sulfur removal. $SO_2$ emissions that would have been generated by the fuel fired equipment at the facility are expected to be reduced by 208 lb/day. The fuel gas stream is treated by the sulfur removal unit where the $H_2S$ in the fuel gas stream is converted to elemental sulfur. The project, thus, results in a net reduction in $SO_x$ emissions.

VOC IPE for FUGITIVE EMISSIONS (new components)

| COMPONENT TYPE | No. of COMPNTS | WEIGHT PERCENT OF VOC | EMISSION FACTOR* LB/HR-# | CONTROL EFFCNCY | EMSSNS LB/HR | EMSSNS LB/DAY |
|---|---|---|---|---|---|---|
| VALVES | | | | | | |
| fuel gas | 83 | 84 | 0.0590 | 99 | 0.0411 | 0.99 |
| make-up H2 | 16 | 58 | 0.0590 | 99 | 0.0055 | 0.13 |
| recyc. H2 | 48 | 29 | 0.0590 | 99 | 0.0082 | 0.20 |
| hvy. liqd. | 180 | 100 | 0.0005 | 99 | 0.0009 | 0.02 |
| lt. liqd. | 23 | 100 | 0.0240 | 99 | 0.0055 | 0.13 |
| FLANGES | | | | | | |
| fuel gas | 101 | 84 | 0.0050 | 99 | 0.0042 | 0.10 |
| make-up H2 | 16 | 58 | 0.0050 | 99 | 0.0005 | 0.01 |
| recyc. H2 | 47 | 29 | 0.0050 | 99 | 0.0007 | 0.02 |
| hvy. liqd. | 192 | 100 | 0.0050 | 99 | 0.0096 | 0.23 |
| lt. liqd. | 25 | 100 | 0.0050 | 99 | 0.0013 | 0.03 |
| PSV'S** | 15 | 100 | 2.3560 | 98 | 0.7068 | 16.96 |
| PUMPS | | | | | | |
| hvy. liqd | 3 | 100 | 0.0460 | 95 | 0.0069 | 0.17 |
| lt. liqd | 1 | 100 | 0.2500 | 95 | 0.0125 | 0.30 |
| COMPRESSORS | | | | | | |
| make-up H2 | 1 | 58 | 1.4000 | 95 | 0.0406 | 0.97 |
| recyc. H2 | 2 | 29 | 1.4000 | 95 | 0.0406 | 0.97 |
| PROCESS DRAINS | | | | | | |
| all streams | | | | | 0.0000 | 0.00 |
| TOTALS | | | | | 0.8849 | 21.24 |

FLUID TYPE

Charge, Reactor Effulent, Stripper Bottoms - Heavy Liquid
Stripper Reflux Light Liquid
Fuel Gas 84% by wt. Non Methane HC (VOC) - Gas
Make-up Hydrogen 58% by wt. Non Methane HC (VOC) - Gas
Recycle Hydrogen 29% by wt. Non Methane HC (VOC) - Gas

* AP-42 EMISSION FACTORS (see page 13)

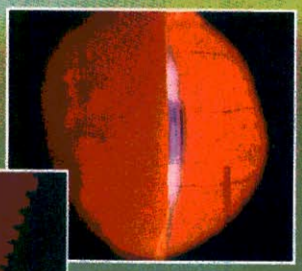
** PSV (pressure relief valves -- vented to flare)

# CALLIDUS TECHNOLOGIES

ETHYLENE TEST FURNACE

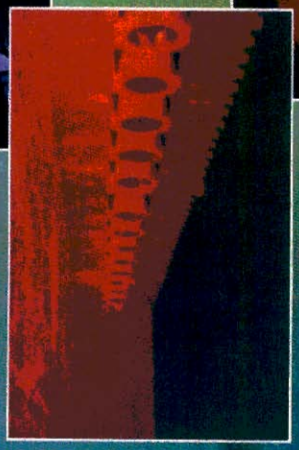


RADIANT WALL BURNER





ULTRA LOW $NO_x$
ULTRA BLUE™ BURNER



DOWNFIRED LOW $NO_x$



FLAT FLAME LOW $NO_x$

*Callidus Burners*

*Industry Leader*

*Compliance Driven*

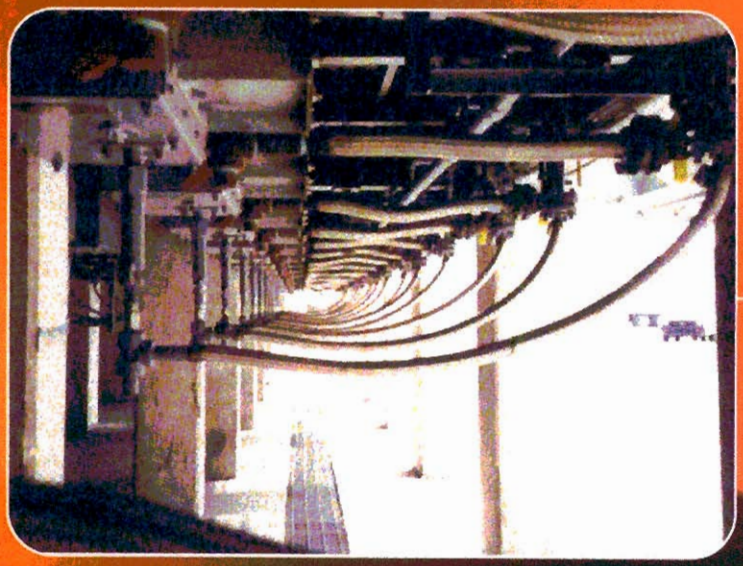
*Certification Assured*

CALLIDUS TECHNOLOGIES INC.
The Environmental & Combustion Experts.

PEXH 000579



*Ethylene technology test furnace*



*U.S. coker furnace installation*



PEXH 000580

# Callidus Has A Burner To Match Your Application

Callidus Technologies Inc. has established itself as a world leader in burner technology. Over the years we have repeatedly broken new ground with innovative new products to meet our customers' requirements. Callidus was the first to break the 10 PPM $NO_X$ barrier, using natural gas, with our patented Ultra Low $NO_X$ burner. Now our new ULTRA BLUE™ burner achieves less than 10 PPM $NO_X$ on a wide range of fuels.

We offer a full range of process heater burners, speciality fired burner equipment, and burner related services for the petroleum and chemical refining industry.

## We Pride Ourselves On [Quality]

Our manufacturing facility employs the highest quality standards in the industry. Callidus quality assurance personnel thoroughly inspect each assembly prior to shipment, reducing field installation time. Callidus fabrication and manufacturing is certified to ISO 9002 standards.

Our burner projects require state-of-the-art equipment. However, our biggest strength is our people. Everyone is highly trained for his specialized task. Ongoing training is regularly scheduled to assure that the high level of quality is maintained from one project to the next.

## Callidus Leads The Way With Engineering [Excellence]

Callidus is committed to providing the highest quality engineered products and services to the combustion industry. We focus on providing a custom designed solution for every project, based on each customer's individual requirements.

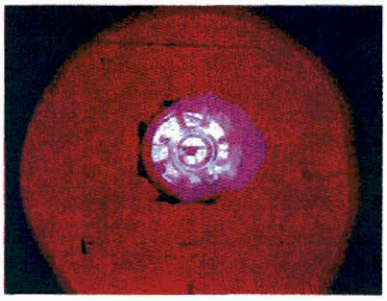
**Our Products and Services Include:**

- Conventional, Low $NO_X$, and Ultra Low $NO_X$ process heater burners
- Burners designed for new heater and retrofit applications
- Direct fired air heaters
- Thermal reaction furnaces and inline heaters for sulfur recovery systems
- Operator training services
- Burner maintenance/tune-up services
- Combustion optimization services

**Our Installation Services:**

- Turnkey installation of Callidus burners, including demolition of existing equipment, field modifications, floor/wall panel replacements, and fuel piping modification
- Single point of responsibility
- Detailed assessment of existing structures to avoid costly changes and delays





***At Callidus We Don't Just Follow The Standards - We Set The Standards***

*• Burners • Flares • Vapor Control Systems • Rotary Kilns • Thermal Oxidizers*



PEXH 000581

## Burners For Refinery [Process] Heaters

Refinery process heaters come in an infinite array of shapes, sizes, and orientations. While most heaters fall into a typical design category, no two heaters are identical, so every heater's burner needs are somewhat unique.

Callidus Technologies offers a comprehensive range of burners for every imaginable combination of fired heater design and stack emissions requirement:

- Premix, Conventional, Low $NO_X$, Ultra Low $NO_X$, and ULTRA BLUE technologies
- Natural draft, forced draft, induced draft applications
- Ambient or preheated combustion air
- Low noise restrictions, including stringent European requirements
- Individual air plenums, or mounting in a common air plenum
- Wide range of fuel gas compositions
- High and low Btu gases
- Single or multiple fuel streams

## Burners For [Reforming] Furnaces

Callidus has supplied thousands of burners for reformers in hydrogen, ammonia and methanol service for every major heater manufacturer including down-fired, up-fired, side-fired and terrace wall configurations. Our designs include the following features:

- Single-piece high-strength tile for down-firing applications
- Conventional, Low $NO_X$, and Ultra Low $NO_X$ designs
- The lowest-$NO_X$ technology currently on the market for down-fired heaters
- Single or multiple gases, including low-pressure, low Btu offgases
- Extensive experience with air distribution modeling for preheated air ductwork
- Designs which minimize down-firing flame buoyancy and mis-alignment of flame
- Approved Haldor-Topsoe burner supplier

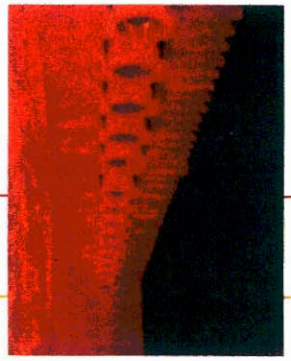
## Burners For [Cracking] Furnaces

Cracking furnaces subject burners to the most abusive firing environment of all process heaters. The intense heat present in these furnaces can lead to the eventual destruction of the burners if they are not properly designed; Ultra Low $NO_X$ burners are the most vulnerable.

Our cracking furnace burner design incorporates numerous mechanical and technological features which help it out-perform our competitors' burners in this harsh environment.

**Design Features Include:**

- Conventional, Low $NO_X$, and Ultra Low $NO_X$ technologies
- Custom designs for hearth, balcony, and radiant wall positions
- "Unitized" burner/tile construction where specified for ease of field installation
- Gas tip/riser anti-plugging/anti-coking design
- Burner tile throat design which eliminates presence of metallic parts which can fail in the intense heat
- Superior turndown performance (up to 10:1 with all gas tips firing)
- Uniform flame pattern for even heat profile on furnace wall and even heat transfer to process tubes
- Jackshaft air control linkages for precise combustion air flow trim



*Downfiring Ultra Low $NO_X$ Burners in Hydrogen Reformer*



PEXH 000582



*Radiant Wall Burner in Side-Fired Cracking Furnace*

## Cracking Furnaces

### Typical Equipment

- Hearth or radiant wall burners
- Conventional, Low $NO_X$, Ultra Low $NO_X$
- Wide range of fuel gases
- High turndown
- Even heat flux profile
- Low maintenance

### Typical Models

- LE-CFSG-W flat flame hearth burners
- LE-CARW radiant wall burners

### Representative Installation

- Ethylene unit on gulf coast
- Floor level LE-CFSG-W hearth burners
- Multiple levels of LE-CARW wall burners
- 0.060 #/MM Btu LHV $NO_X$ requirement
- Methane/hydrogen fuel

## Process Heaters

### Typical Equipment

- Round flame or flat flame
- Noise-reducing windbox
- Continuous pilot
- Single gas connection
- Multiple position high-efficiency damper

### Typical Models

- CUB-W ULTRA BLUE
- LE-CSG-W Ultra Low $NO_X$
- CSG-W Staged Fuel Low $NO_X$
- CRG-W Conventional

### Representative Installation

- West coast crude furnace
- LE-CSG-W Ultra Low $NO_X$ burners
- 1600˚F firebox
- 15% excess air
- Ambient air
- Refinery fuel gas
- 0.033 #/MM Btu HHV $NO_X$

## Reforming Furnaces

### Typical Equipment

- Downfiring burners
- Round flame
- Fuel gas + PSA off-gas
- 1850˚F firebox
- Ambient air
- 0.040 #/MM Btu $NO_X$

### Typical Models

- LE-CSG-WDF-PSA for non-mixed Gases
- CFRG-WDF for mixed PSA + fuel gases
- LE-CARW for radiant wall

### Representative Installation

- Hydrogen plant in upper midwest
- Forty-two (42) LE-CSG-WDF-PSA down-firing ULN burners
- Separate fuel & PSA gas connections
- Ambient air



PEXH 000583



## Coking Furnaces

### Typical Equipment

- Flat flame burners firing along wall
- Noise-reducing windbox
- High turndown
- Even heat flux profile
- High-efficiency damper

### Typical Models

- LE-CFSG-W Ultra Low $NO_x$
- CFSG-W Staged Fuel Low $NO_x$
- CFRG-W Conventional

### Representative Installation

- New coker in Ohio
- 144 Ultra Low $NO_x$ burners
- Ambient air
- Refinery fuel gas
- 1600°F firebox
- 0.040 #/MM Btu $NO_x$

## Burner Test Facility

### Equipment

- Seven test furnaces
- Up-firing
- Down-firing
- Horizontal-firing
- Radiant wall
- Fuel blending system
- Completely automated data acquisition
- Air-preheat system
- Experienced engineering staff
- Highly-trained test technicians
- Complete test facility machine shop staff



*Multiple radiant wall burners firing in unison in Ethylene test furnace.*



PEXH 000584

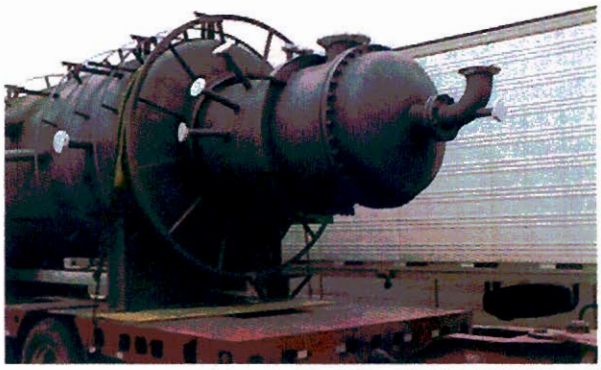
## Burners For [Coking] Furnaces

Like cracking furnaces, coking furnace efficiency is closely tied to the burners' ability to deliver a uniform heat flux pattern to the wall, and then to the process tubes. Our coker and cracking furnace burners share many of the same design features:

- Conventional, Low $NO_X$, and Ultra Low $NO_X$ technologies
- Gas tip/riser anti-plugging/anti-coking design
- Burner tile throat design which eliminates presence of metallic parts which can fail in the intense heat
- Superior turndown performance (up to 10:1 with all gas tips firing)
- Uniform flame pattern for even heat profile on furnace wall and even heat transfer to process tubes
- Jackshaft air control linkages for precise combustion air flow trim

## [Sulfur] Plant Equipment

- Thermal reaction furnaces
- Inline mixers/burners
- Acid gas burners
- LMV burners



*Reaction furnace with acid gas burner ready for shipment*

## [Burner] Test Facility

Our burner testing facility is in continual use for burner technology research and design and customer witnessed demonstrations. Burner test results are only as reliable and accurate as the simulation; our array of test furnaces allows us to closely match our customers' actual field operating conditions, providing results which will accurately predict the measured performance of the same burners once installed in customers' heaters.

Our testing facility south of Tulsa, Oklahoma features the following:

- Seven water-cooled fired heaters
- Vertical cylindrical heaters, box heaters, horizontal heaters
- Specialty heaters for use when firing radiant wall burners
- Customer-designed Ethylene service testing heater with 45' tall radiant section, ability to fire multiple burners at multiple levels in unison
- Ample platforms and sight ports to observe burner flame pattern from multiple vantage points
- Flux measurement ports to allow optimization of heat flux profile
- Heaters fully-instrumented for remote gathering and compiling of live test parameters
- Each heater equipped with a video camera to allow taping of burner testing inside heater for internal and customer use

## Callidus Technologies Offers [The Best] In Design, Quality, Performance And Delivery

## *[Unequaled] Research And Development*

Our industrial scale research center is a fully instrumented and computerized facility totally devoted to research and development of new products, new combustion processes, and problem solving applications. Our R&D center also serves as a test center for regulatory agencies as well as private clients. The test center has the capability to fully test and provide reports on all types of burner configurations. The Callidus test facility investment underscores our commitment to being the leader in the combustion industry.

## *[Advanced] Manufacturing And Fabrication Capabilities*

Upgrading our manufacturing and fabrication operation is an ongoing process at Callidus Technologies. Our current facility occupies over 30,000 sq. ft. consisting of the latest manufacturing techniques and equipment. As a world player in the combustion equipment market, some of our fabrication takes place around the world in strategic locations. Proprietary items are fabricated at our U.S. facility. This "satellite" approach makes good economic sense assuring that the customer gets the absolute best equipment for their installation.

At Callidus, quality assurance is everyone's job. Every step of the project is consistently reviewed to make sure that we live up to the expectations of our customers. Where applicable, each piece of equipment is pre-assembled and tested to assure performance. All machining and fabrication of critical components are accomplished in-house or by trusted experienced suppliers. Our rigorous quality inspection program is underscored by our ISO9002 certification.



***Burner research facility***

## *Callidus Technologies Inc. - best in design, quality, performance and delivery*


**Callidus Japan**
Phone: 011-81-448508209
FAX: 011-81-448508217

**Home Office:** 7130 South Lewis, Suite 335 • Tulsa*, OK 74136
Phone: 918/496-7599 • FAX: 918/496-7587 • **Website:** www.callidus.com
Sales offices world wide.

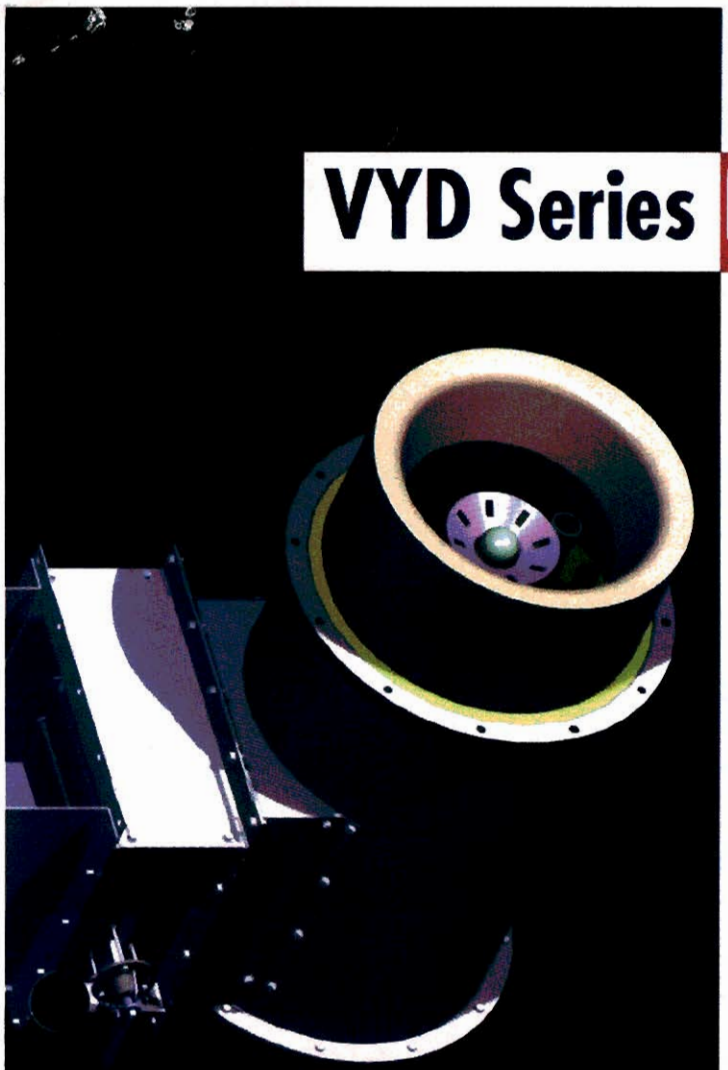
**Callidus U.K.**
Phone: 011-44-1438747550
FAX: 011-44-1438747551


CALLIDUS TECHNOLOGIES INC.
The Environmental & Combustion Experts.

***We Don't Just Follow The Standards — We Set The Standards.***

REGISTERED COMPANY ISO 9002 SGS *

# VYD Series Burners

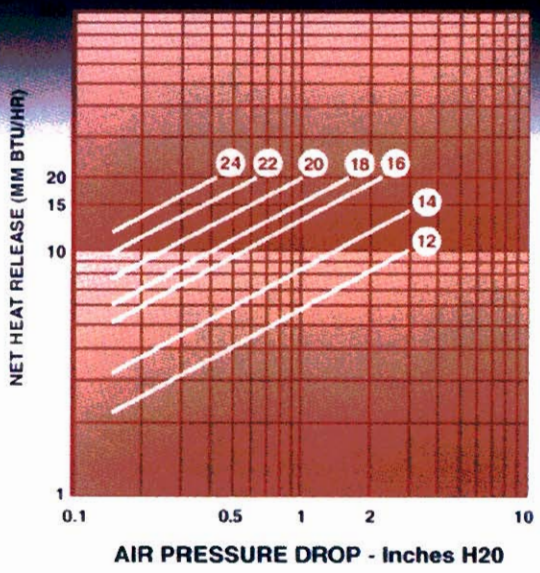


- **Compact flames**
- **Superb turndown ratios**
- **Durable – many in service over 30 years**

The VYD family epitomizes John Zink's traditional raw gas burners by exhibiting reliable, conventional design and operation. The VYD burners safely and efficiently burn most fuel gases and will afford superb stability. An extremely wide turn down range makes it possible to satisfactorily operate with a wide range of gases – high hydrogen to heavy hydrocarbons (butane). VYD burners have a small footprint and provide compact flames.

| VYD Emissions | |
|---|---|
| Fuel | Tulsa Natural Gas |
| Excess $O_2$ (Air) | 3% (15%) |
| Bridgewall Temp. (BWT) | 1400°F |
| Predicted NOx | 95 ppm (0.132 lb/MMBtu) |

## VYD Burner Capacities




JOHN ZINK
JOHN ZINK COMPANY LLC

PEXH 000587

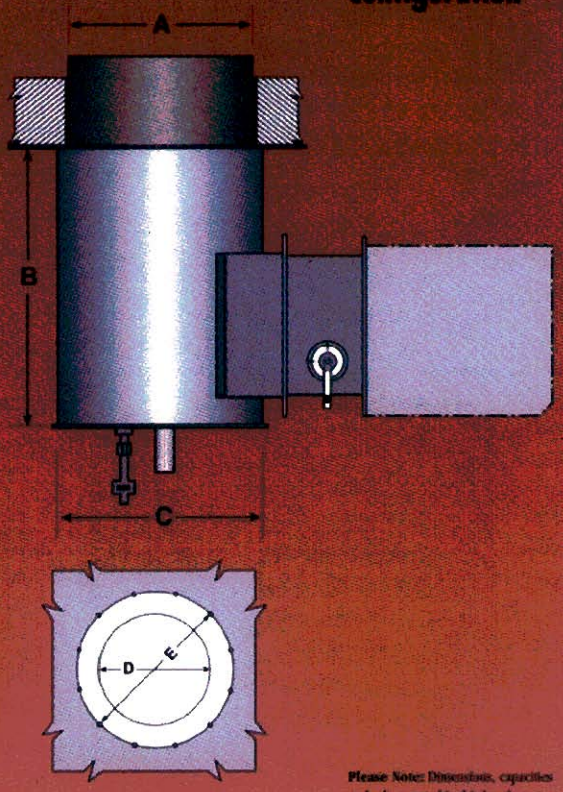
# VYD Series Burners

The PVYD models come complete with their own plenum and can be used in either forced or natural draft applications. The integral plenum has an inlet damper which allows for easy individual control of combustion air.

## Burner Quick Facts

- Fuel: gas only
- Flame Shape: round
- Burner Configuration: vertical/horizontal
- NOx Reduction Method: none
- Heat Release Range: 2 – 20 MMBtu/hr

### Burner Configuration




**Please Note:** Dimensions, capacities and values stated in this brochure are for reference purposes only. Actual numbers may vary, depending upon the specific equipment requirements.

| MODEL VYD | | Inches | | | | |
|---|---|---|---|---|---|---|
| | | A | B | C | D | E |
| Burner Sizes | 12 | 18.50 | 28.125 | 23.50 | 14.50 | 22.00 |
| | 14 | 20.50 | 29.25 | 23.50 | 16.50 | 22.00 |
| | 16 | 22.50 | 35.00 | 27.50 | 18.50 | 26.00 |
| | 18 | 24.50 | 38.00 | 27.50 | 20.50 | 26.00 |
| | 20 | 26.50 | 38.125 | 29.50 | 22.50 | 28.00 |
| | 22 | 28.50 | 41.00 | 31.50 | 24.50 | 30.00 |
| | 24 | 30.50 | 44.00 | 32.50 | 26.50 | 31.00 |

| MODEL VYD | | Millimeters | | | | |
|---|---|---|---|---|---|---|
| | | A | B | C | D | E |
| Burner Sizes | 12 | 470 | 714 | 597 | 368 | 559 |
| | 14 | 521 | 743 | 597 | 419 | 559 |
| | 16 | 572 | 889 | 699 | 470 | 660 |
| | 18 | 622 | 965 | 699 | 521 | 660 |
| | 20 | 673 | 972 | 749 | 572 | 711 |
| | 22 | 724 | 1041 | 800 | 622 | 762 |
| | 24 | 775 | 1118 | 826 | 673 | 787 |


JOHN ZINK
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www.johnzink.com

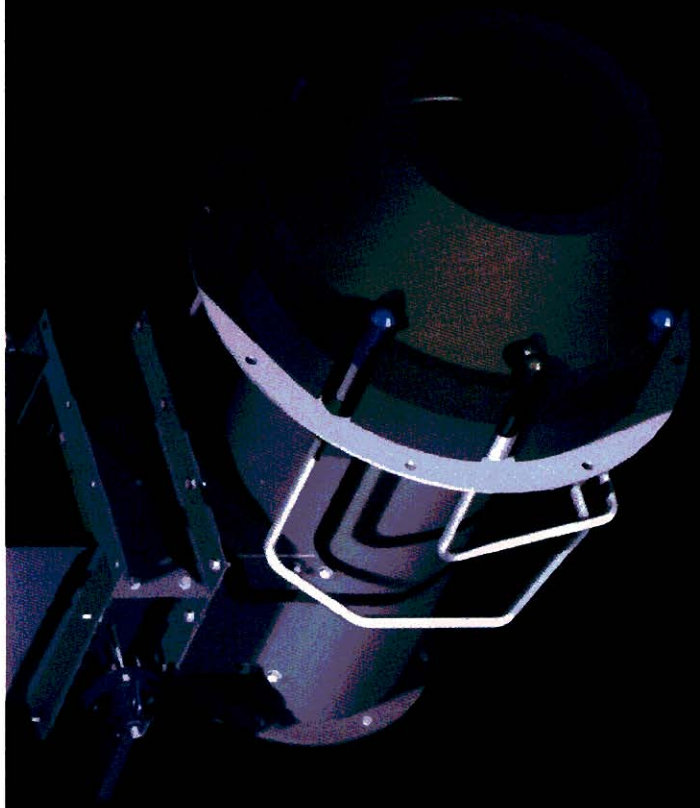

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# SMR Series Burners

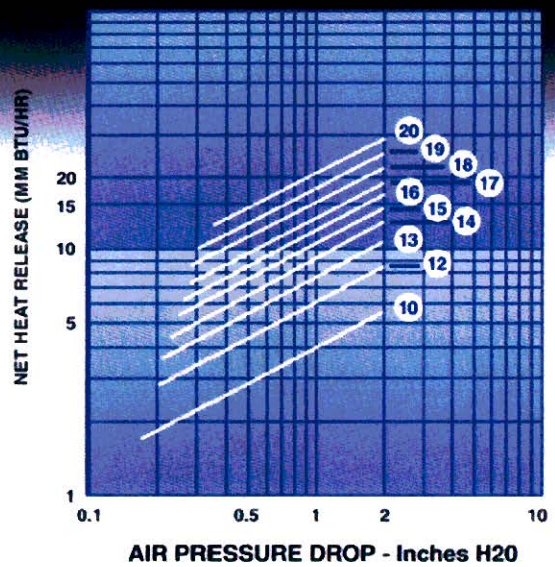
Patented*

- INFURNO$_x$™ technology — 12 ppm NO$_x$
- Best Available Control Technology (BACT)
- Flame stabilizes on tile for dramatically increased service life
- Exceptional stability



As a major supplier of combustion products to the hydrocarbon and petrochemical industries, John Zink® has spent millions of dollars over the last several years developing low emission burners. INFURNOx technology, our latest contribution, produces inherently stable burners with superior turndown and operating flexibility. The Swirl Mix Recirculation (SMR) burners use fuel gas energy and natural convection to promote in-furnace flue gas inspiration, a key component of John Zink's INFURNOx technology. In each design the flame is stabilized on a THERMBOND® refractory ledge instead of a bluff body. The primary advantage of these Ultra LoNOx burners is that strict emission limits are met without sacrificing furnace thermal efficiency or adding costly FGR systems or catalyst.

## SMR Burner Capacities




## SMR Emissions

| | |
|---|---|
| Fuel | Tulsa Natural Gas |
| Excess $O_2$ (Air) | 3% (15%) |
| Bridgewall Temp. (BWT) | 1400°F |
| Predicted NOx | 12 ppm (0.017lb/MMBtu) |

JOHN ZINK
JOHN ZINK COMPANY LLC

*THERMBOND is a registered trademark of Stellar Materials, Inc.

PEXH 000589

# SMR Series Burners

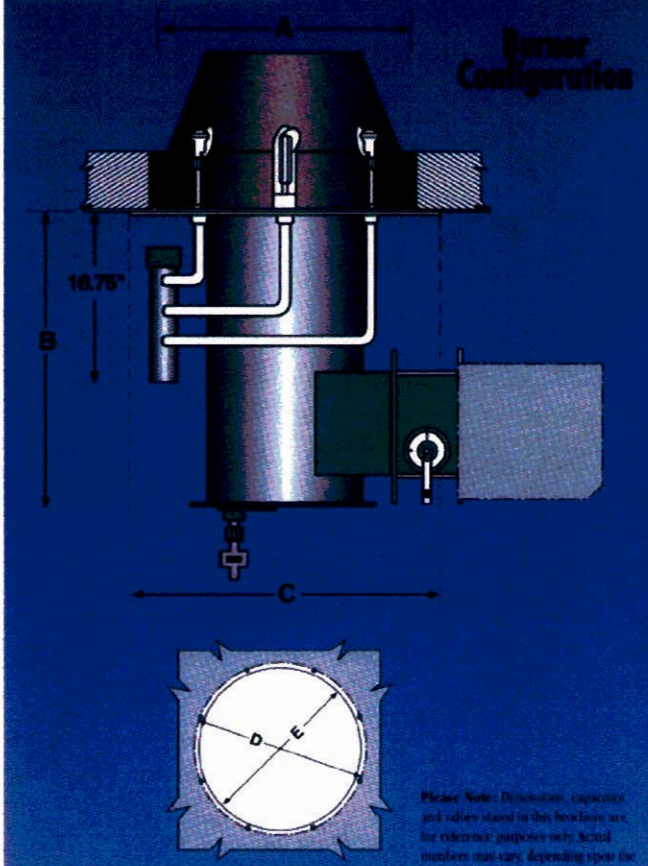
The PSMR models come complete with their own plenums and can be used in either forced or natural draft applications. The integral plenum provides an opposed motion, dual vane inlet damper to control combustion air flow.

The SMR-PC model is designed for use in a common plenum chamber. It is equipped with an air register which allows for easy individual control of combustion air.

The SMR-PC-CR uses vertical vanes instead of sliding concentric cylinders for combustion air control. This is recommended for forced air applications with high preheat temperatures.

## Burner Quick Facts

- Fuel: gas only
- Flame Shape: round
- Burner Configuration: vertical/horizontal
- NOx Reduction Method: internal flue gas recirculation
- Heat Release Range: 2–25 MMBtu/hr




Please Note: Dimensions, capacities and values stated in this brochure are for reference purposes only. Actual numbers may vary, depending upon the specific equipment requirements.

| MODEL SMR | | Inches | | | | |
|---|---|---|---|---|---|---|
| | | A | B | C | D | E |
| Burner Sizes | 10 | 21.75 | 30.25 | 25.75 | 24.25 | 22.75 |
| | 11 | 22.75 | 31.25 | 26.75 | 25.25 | 23.75 |
| | 12 | 23.75 | 27.50 | 27.75 | 26.25 | 24.75 |
| | 13 | 24.75 | 29.50 | 28.75 | 27.25 | 25.75 |
| | 14 | 25.75 | 31.50 | 29.75 | 28.75 | 26.75 |
| | 15 | 26.75 | 33.50 | 30.75 | 29.25 | 27.75 |
| | 16 | 27.75 | 35.50 | 31.75 | 30.25 | 28.75 |
| | 17 | 28.75 | 37.50 | 32.75 | 31.25 | 29.75 |
| | 18 | 29.75 | 39.50 | 33.75 | 32.25 | 30.75 |
| | 19 | 30.75 | 41.50 | 34.75 | 33.25 | 31.75 |
| | 20 | 31.75 | 43.50 | 35.75 | 34.25 | 32.75 |

| MODEL SMR | | Millimeters | | | | |
|---|---|---|---|---|---|---|
| | | A | B | C | D | E |
| Burner Sizes | 10 | 553 | 768 | 654 | 616 | 578 |
| | 11 | 578 | 794 | 680 | 641 | 603 |
| | 12 | 603 | 699 | 705 | 667 | 629 |
| | 13 | 629 | 749 | 730 | 692 | 654 |
| | 14 | 654 | 800 | 756 | 718 | 680 |
| | 15 | 680 | 851 | 781 | 743 | 705 |
| | 16 | 705 | 902 | 806 | 768 | 730 |
| | 17 | 730 | 953 | 832 | 794 | 756 |
| | 18 | 756 | 1003 | 857 | 819 | 781 |
| | 19 | 781 | 1054 | 883 | 845 | 807 |
| | 20 | 807 | 1105 | 908 | 870 | 832 |

JOHN ZINK
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UNITED STATES OF AMERICA
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Fax: +1-918-234-2700
www.johnzink.com

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* SMR Series is covered by one or more of the following Patents: U.S. Pat. No. 5344307, 5238395, 5275552, 5269678, 5195884, 5154596, 5098282, Canada Pat. No. 2076689, 2076705, Japan Pat. No. 2633453, 2633452, Taiwan Pat. No. NI-66951

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– DRAFT –

– Cook –

# TITLE V APPLICATION REVIEW

Administrative Amendment
Project #: S-1040631

Engineer: Duane Goodwin
Date: April 23, 2004

Facility Number: S-37
Facility Name: Kern Oil & Refining Co. (Kern)
Mailing Address: 7724 E. Panama Lane
Bakersfield, CA 93307-9210

Contact Name: Jerry Frost
Phone: (661) 845-0761

Responsible Official: Bruce Cogswell
Title: Vice President, Manufacting

## I. PROPOSAL

Kern Oil & Refining Company proposes to incorporate the requirements from ATCs S-37-3-4, '-4-9, '-6-10, '-77-9, and '-103-4 into the Title V permit. The ATCs were issued under District project 1040631 and modify the operating permits to include startup and shutdown periods for each heater/boiler in each permit unit. The ATCs were issued with a Certificate of Conformity with procedural requirements of 40 CFR part 70, therefore this project is considered administrative amendment. ATCs S-37-4-7, '-77-8 and '-103-1 were used as a bases for ATCs S-37-4-9, '-77-9 and '-103-1, therefore these ATCs will be implement concurrently with ATCs S-37-4-9, '-77-9 and '–103-4.

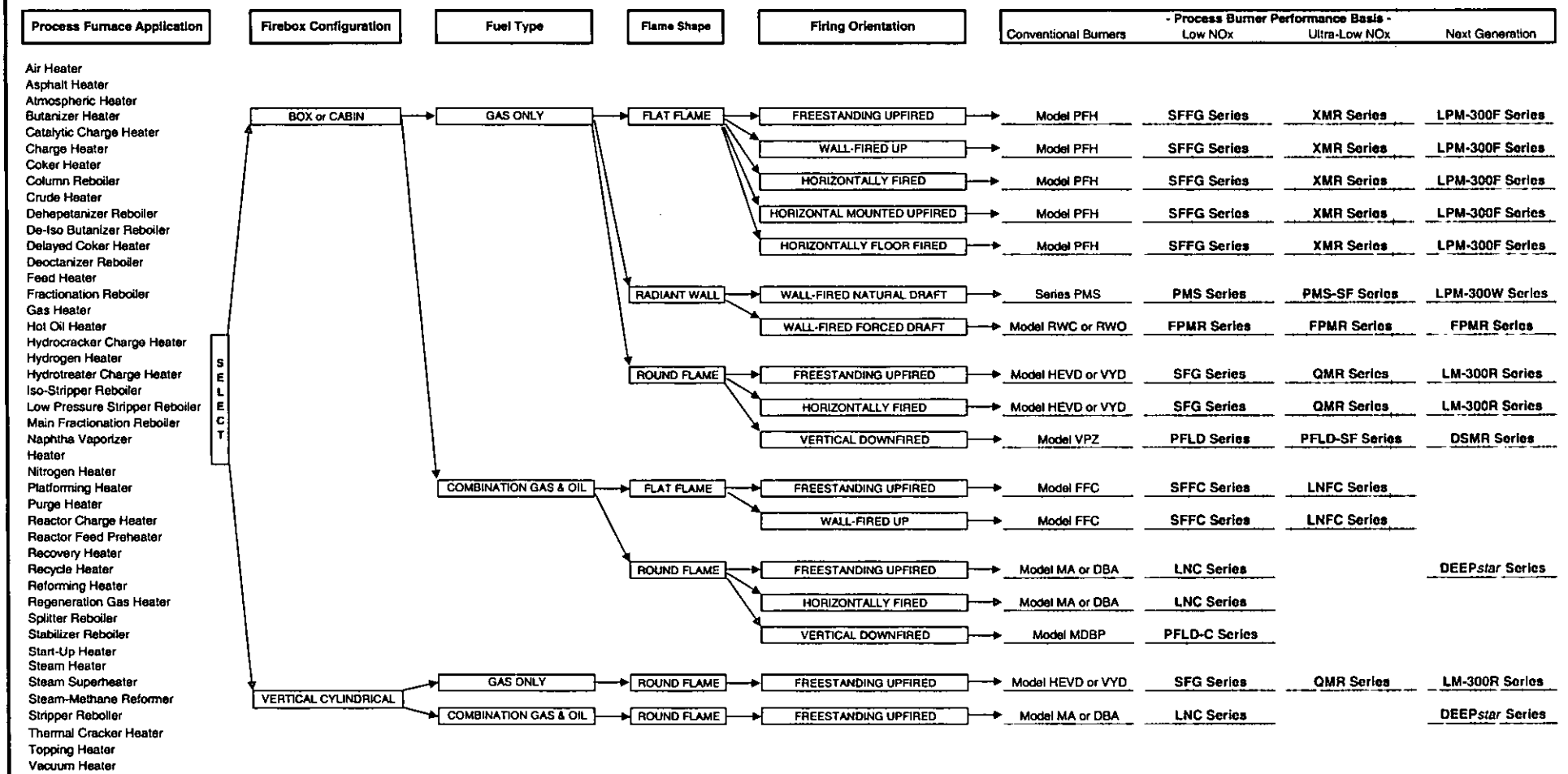
The purpose of this evaluation is to identify all applicable requirements, determine if the facility will comply with the applicable requirements and to provide the legal and factual basis for the proposed revisions.

## II. FACILITY LOCATION

Kern Oil and Refining Company is located at 7724 E. Panama Lane at the intersection of Panama Lane and Weedpatch Highway (Section 25, Township 30S, Range 28E), in Bakersfield, California, in a CO-Attainment area.

JOHN ZINK
A KOCH INDUSTRIES COMPANY

# PROCESS BURNER SELECTION MATRIX




**CONTACT: For more information on process burner products or other clean-air combustion applications, please call or write for a John Zink combustion engineer.**


**JOHN ZINK COMPANY WORLD HEADQUARTERS**

11920 East Apache Street, Tulsa, Oklahoma 74116 USA PHONE: 918.234.1800 FAX: 918.234.1806 EMAIL: jzbuinfo@kochind.com WEB: www.johnzink.com



Revised: 17-May-2001

**Kern Oil & Refining Co.**
**Facility # S - 37**

| **District Project No. S-1040995**<br>**New Sulfur Plant** | | Estimated Actual Stack Flow | | Dry, Excess-Air Free Basis | | Mass Emission | Complaince Margin Added Dry, Excess-Air-Free Basis | |
|---|---|---|---|---|---|---|---|---|
| Mol. Wt. | | #mol/hr | ppmv | #mol/hr | ppmv | lb/hr | ppmv | lb/hr |
| 2.0159 | H2 | 3.3247 | | 3.3247 | | | | |
| 18.0153 | H2O | 21.0639 | | | | | | |
| 28.0104 | CO | 0.0711 | 356.4 | 0.0711 | 411.1 | 1.992 | 493.4 | 2.390 |
| 17.0304 | NH3 | 0.0020 | 9.8 | 0.0020 | 11.3 | 0.033 | 13.5 | 0.040 |
| 28.0134 | N2 | 149.2395 | | 149.2395 | | | | |
| 31.9988 | O2 | 5.5231 | | | | | | |
| 44.0098 | CO2 | 20.2749 | | 20.2749 | | | | |
| 34.0799 | H2S | 0.0009 | 4.6 | 0.0009 | 5.3 | 0.031 | 6.3 | 0.037 |
| 64.0628 | SO2 | 0.0365 | 182.9 | 0.0365 | 211.0 | 2.338 | 253.2 | 2.806 |
| 60.0744 | COS | 0.0003 | 1.3 | 0.0003 | 1.5 | 0.016 | 1.8 | 0.019 |
| 76.1390 | CS2 | 0.0004 | 2.0 | 0.0004 | 2.3 | 0.030 | 2.7 | 0.036 |
| 46.0055 | NOx as NO2 | 0.0048 | 24.1 | 0.0048 | 27.8 | 0.221 | 33.4 | 0.266 |
| | Total #mol/hr | 199.5420 | | 172.9550 | | | | |
| | ppmv total reduced Sulfur | | 9.8 | | 11.3 | 0.076 | 13.5 | 0.1 |
| | ppmv total SO2 equivalent | | 192.7 | | 222.3 | 2.463 | 266.8 | 3.0 |
| | Total lb/hr | 5640.3 | | 5084.1 | | | | |
| | | | | | | | | |
| | Stack Temperature, °F | 1200 | | 1200 | | | | |
| | Stack Exit Pres., psia | 14.45 | | 14.45 | | | | |
| | | | | | | | | |
| | MSCFH | 75.722 | | 65.633 | | | | |
| | MACFH | 245.951 | | 213.181 | | | | |

1000 ar mth an.

200 ft³/mn × 64 lb / 379.5 × .0757 = 2.55 lb/hr SO₂

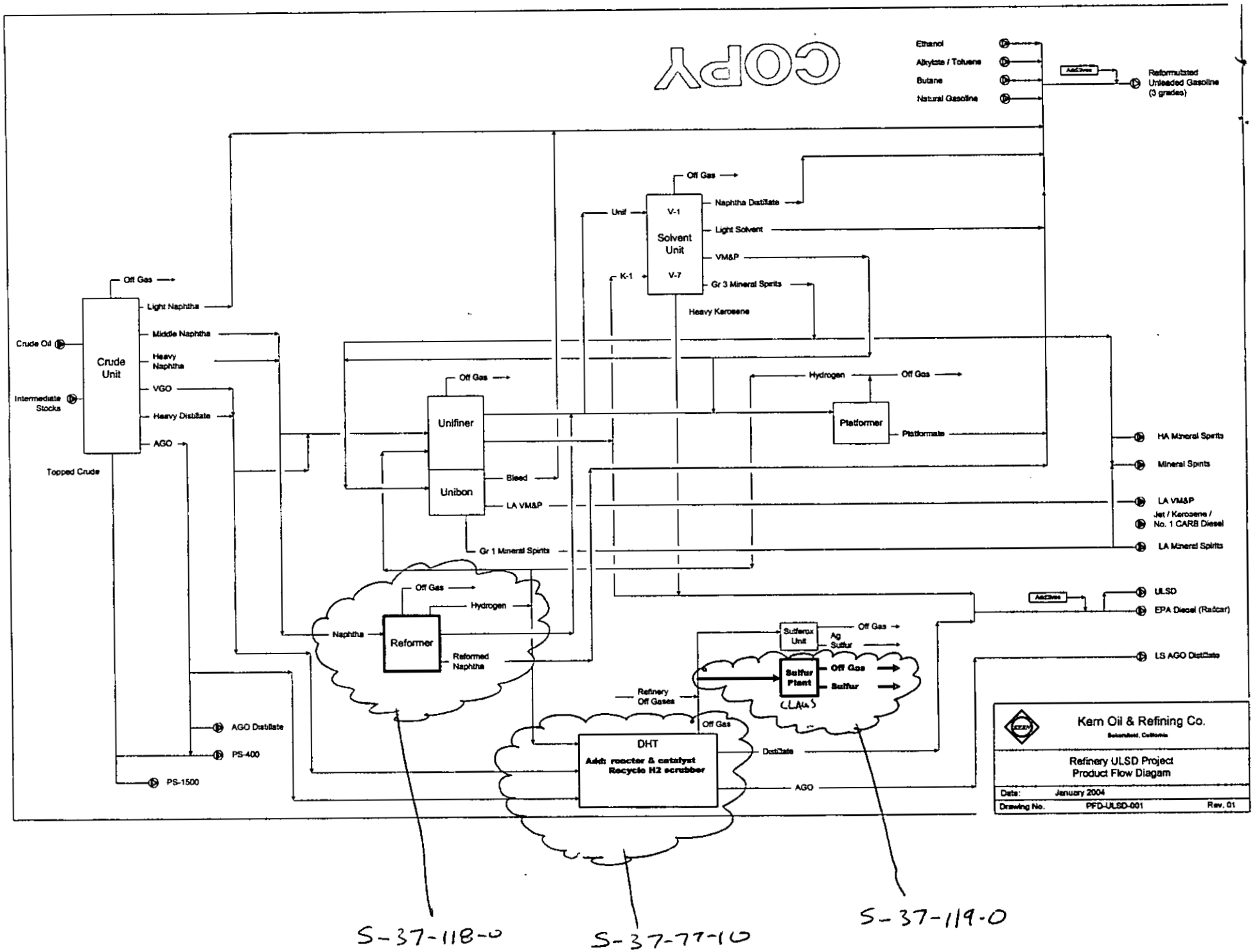
137 lb/hr / 3,215 lb/day

6 1

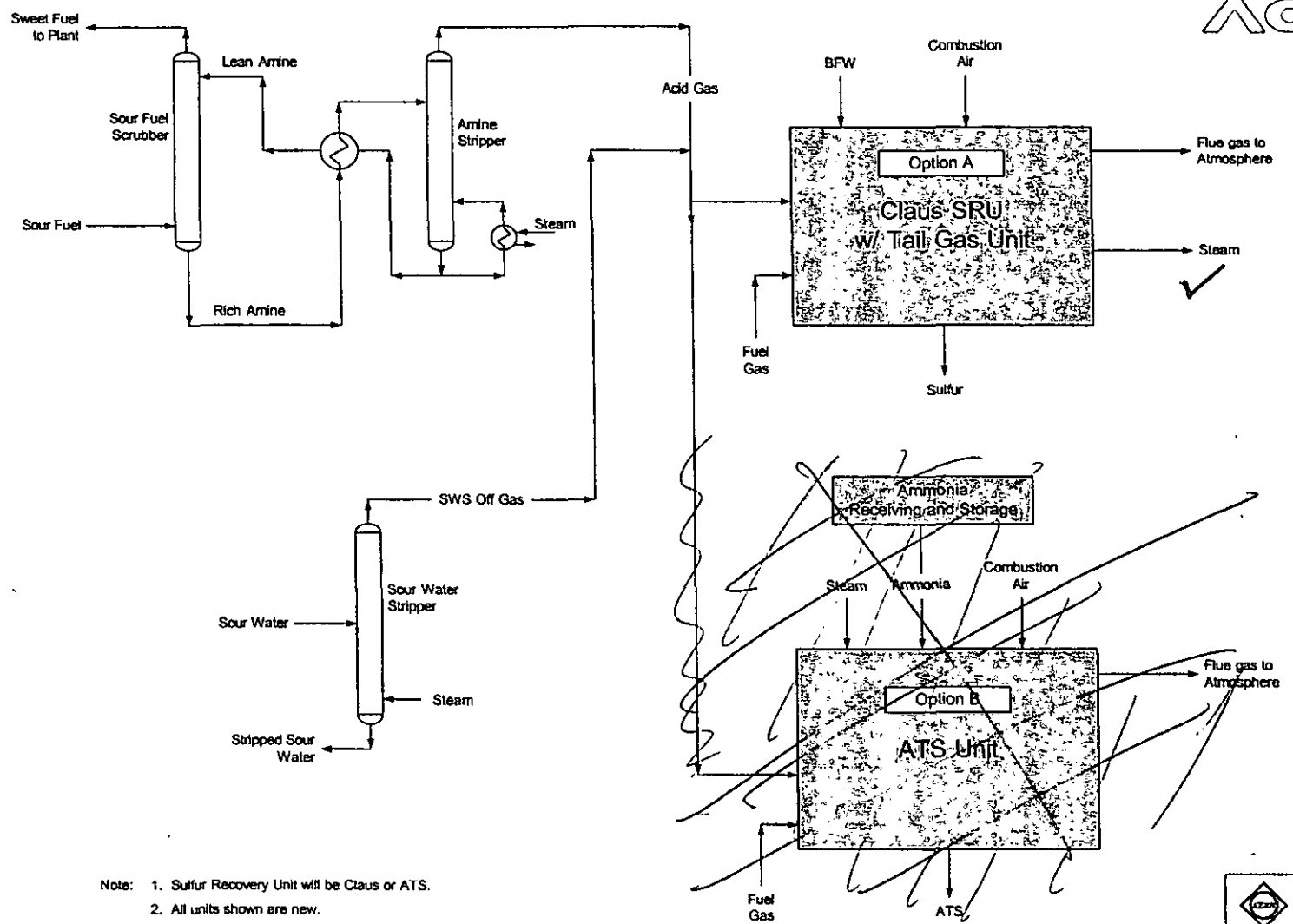
startup/shutdown

1 lb-mol SO₂ / 1 lb-mol × 64 lb / 379.5 × .24595 = 8.29 lb/hr

COPY


Ethanol
Alkylate / Toluene
Butane
Natural Gasoline
Additives
Reformulated Unleaded Gasoline (3 grades)
Off Gas
Naphtha Distillate
Unif
V-1
Solvent Unit
V-7
K-1
Light Solvent
VM&P
Gr 3 Mineral Spirits
Heavy Kerosene
Off Gas
Light Naphtha
Middle Naphtha
Heavy Naphtha
VGO
Heavy Distillate
AGO
Crude Oil
Intermediate Stocks
Crude Unit
Topped Crude
Off Gas
Unifiner
Unibon
Bleed
LA VM&P
Gr 1 Mineral Spirits
Hydrogen
Off Gas
Platformer
Platformate
HA Mineral Spirits
Mineral Spirits
LA VM&P
Jet / Kerosene / No. 1 CARB Diesel
LA Mineral Spirits
Off Gas
Hydrogen
Naphtha
Reformer
Reformed Naphtha
Additives
ULSD
EPA Diesel (Ratcar)
LS AGO Distillate
Sulferox Unit
Off Gas
Ag Sulfur
Sulfur Plant
Off Gas
Sulfur
CLAUS
Refinery Off Gases
Off Gas
DHT
Add: reactor & catalyst
Recycle H2 scrubber
Distillate
AGO
AGO Distillate
PS-400
PS-1500
Kern Oil & Refining Co.
Bakersfield, California
Refinery ULSD Project
Product Flow Diagam
Date: January 2004
Drawing No. PFD-ULSD-001 Rev. 01
S-37-118-0
S-37-77-10
S-37-119-0

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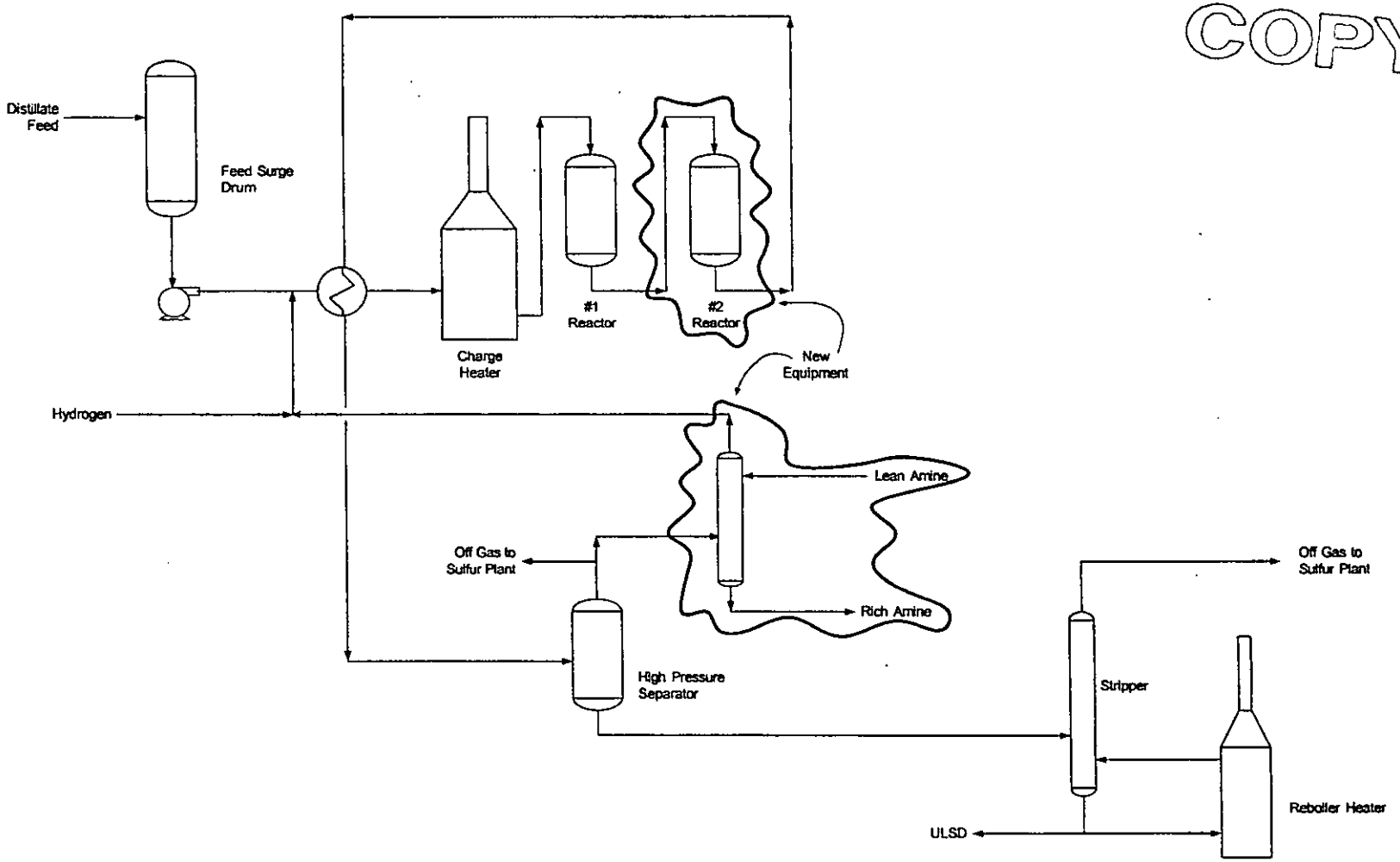

Note: 1. Sulfur Recovery Unit will be Claus or ATS.
2. All units shown are new.

Kern Oil and Refining Co.
Bakersfield, California

Sulfur Recovery Unit
Process Flow Diagram

Date: January 2003
Drawing No. Rev. 01

COPY

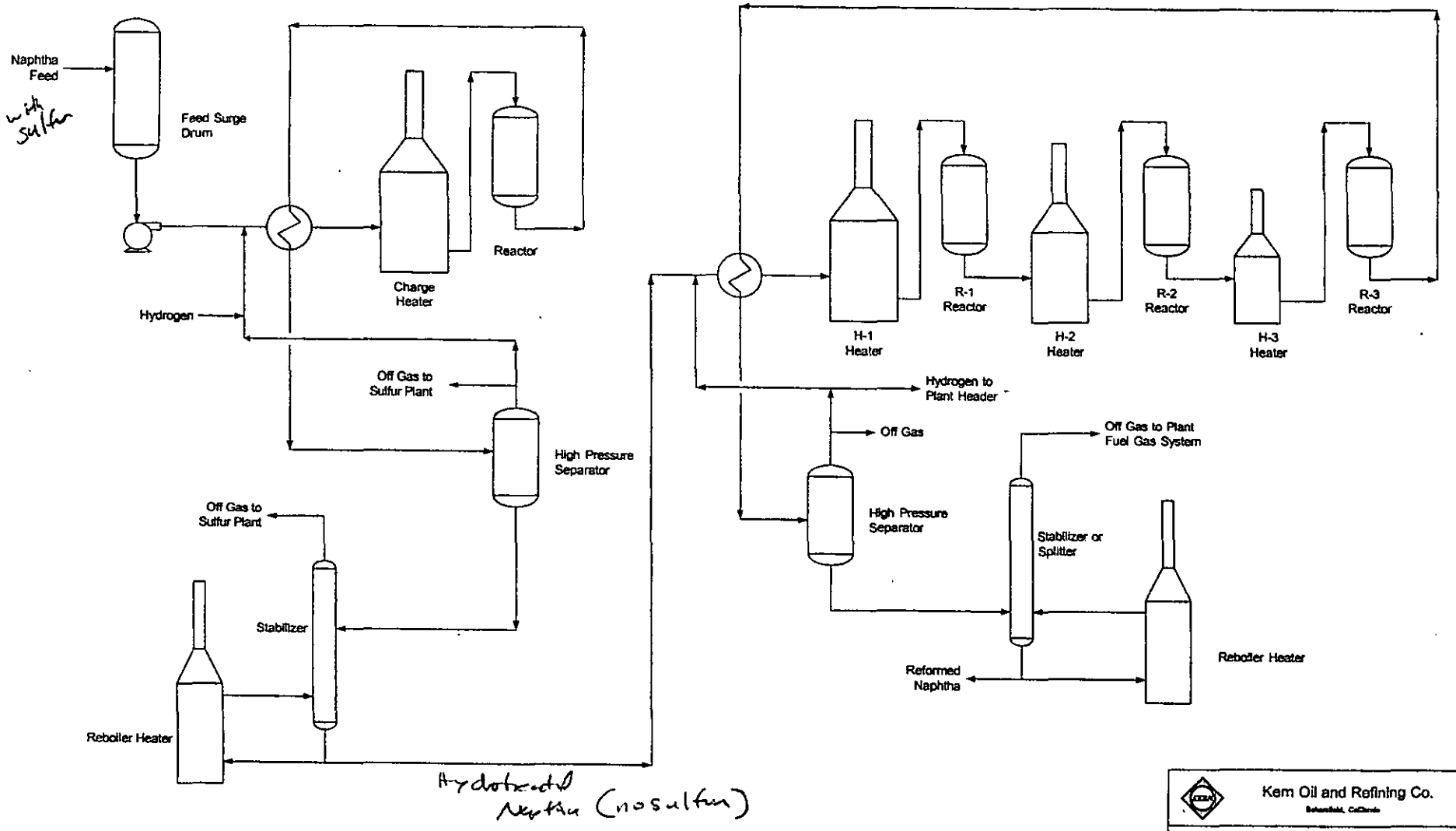



Kern Oil and Refining Co.
Bakersfield, California

DHT Unit
Process Flow Diagram

Date: January 2004
Drawing No. Rev. 01

S-37-77-10




Kern Oil and Refining Co.
Bakersfield, California

New Reformer Unit
Process Flow Diagram

Date: January 2004

Drawing No. Rev. 01

S-37-118-0

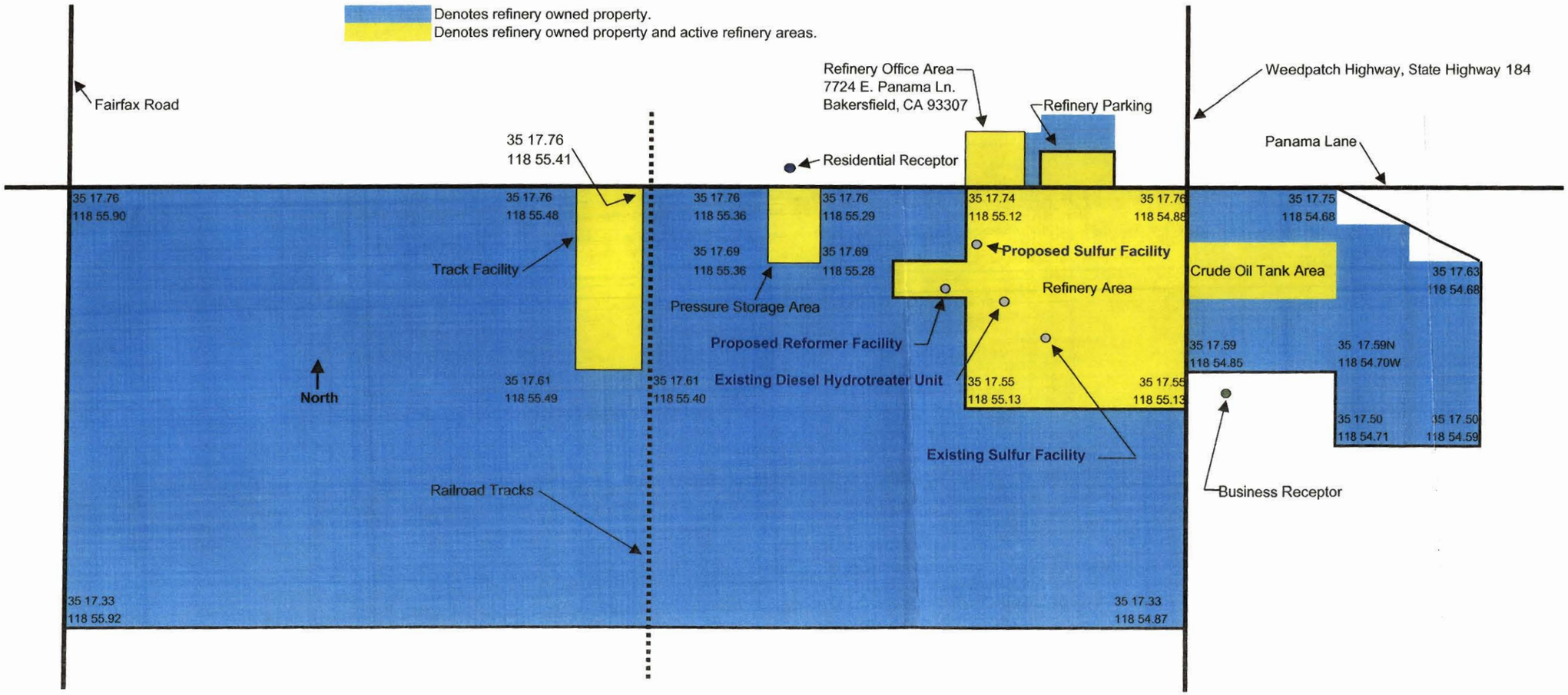
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## Coordinates | Kern Oil & Refining Co. | Ultra-Low Sulfur Diesel Project

| Permit Number | Permit Description | Longitude Degrees | Minutes | Seconds | Latitude Degrees | Minutes | Seconds | |
|---|---|---|---|---|---|---|---|---|
| S-37-77 | Exisiting DHT Unit | 35 | 17 | 64 (N) | 118 | 55 | 9 (W) | |
| S-37-78 | Existing Sulfur Facility | 35 | 17 | 60 (N) | 118 | 55 | 5 (W) | |
| S-37- | Proposed Reformer Facility | 35 | 17 | 63 (N) | 118 | 55 | 14 (W) | |
| S-37- | Proposed Sulfur Facility | 35 | 17 | 70 (N) | 118 | 55 | 12 (W) | |
| S-37-104 | Vacuum Tower | 35 | 17 | 73 (N) | 118 | 55 | 12 (W) | This project was not implemented and expires July 2004. |
| S-37-113 | SRU No. 2 | 35 | 17 | 60 (N) | 118 | 55 | 06 (W) | This project was not implemented and expired in December 2003. |
| S-37-114 | Cogeneration Unit | 35 | 17 | 74 (N) | 118 | 55 | 08 (W) | |
| Residence Receptor | | 35 | 17 | 76 (N) | 118 | 55 | 33 (W) | |
| Business Receptor | | 35 | 17 | 57 (N) | 118 | 54 | 81 (W) | |

**Refinery Overview - Not To Scale**



# CALLIDUS TECHNOLOGIES, LLC



## Low Emission Burners

Ultra Low NOx burners incorporate two key technologies in order to lower a burner's peak flame temperature and therefore NOx formation. By staging the combustion as well as inducing inert, relatively cool furnace flue gas into the fuel/air mixture, a Low Emission burner achieves maximum NOx reduction.

**Callidus Ultra Low NOx Burners Feature:**

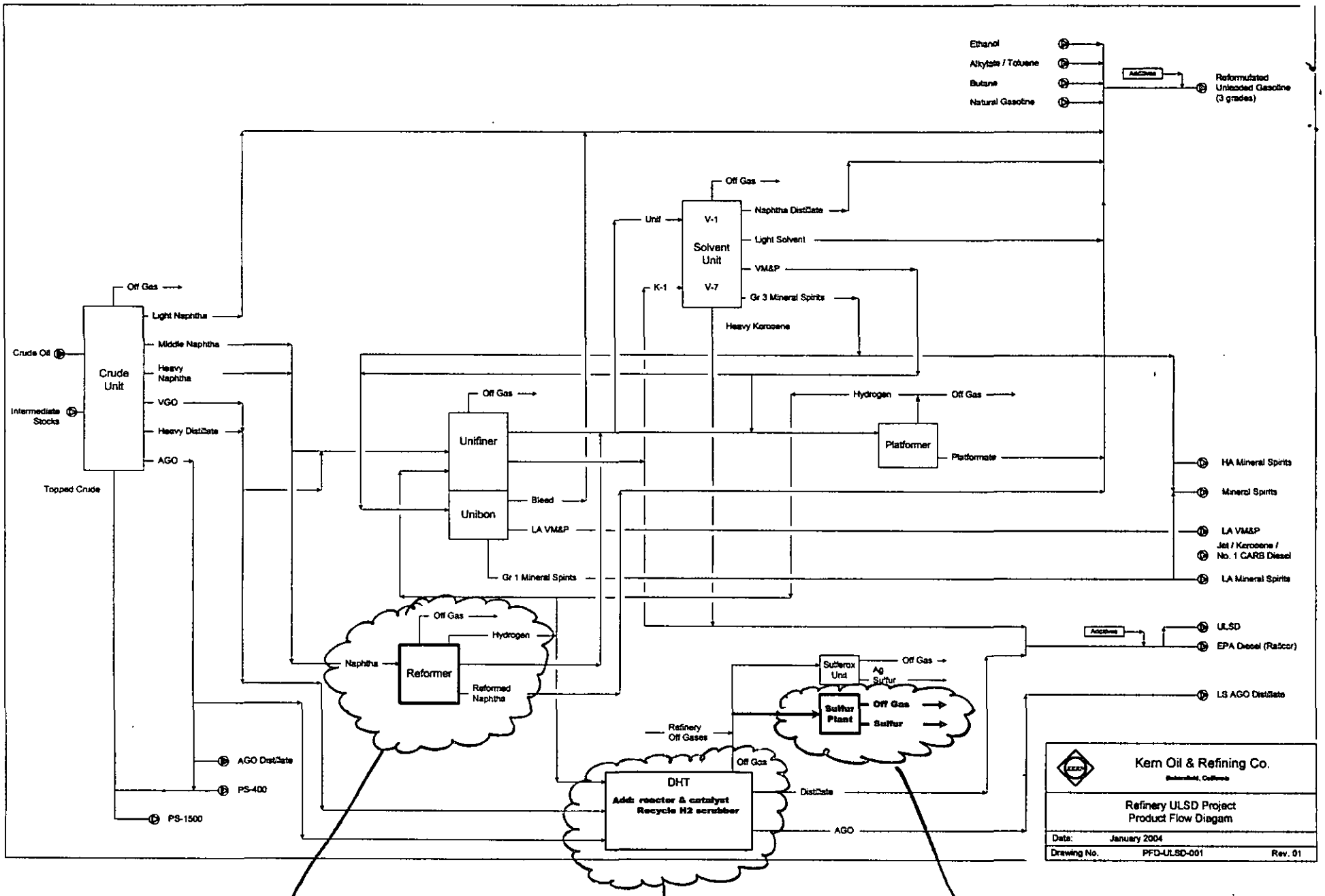
- Maximum possible reduction in NOx formation
- NOx lowering mechanism is completely integral to burner design
- Steam injection not needed
- Uniform heat flux transfer to tubes
- Can burn a wide range of fuels
- High turndown capability
- Can be fired vertically up or down, or horizontally
- Can be adapted for short flame length requirements

**Typical Applications for Ultra Low NOx Burners:**

- Very low NOx emissions are required
- Uniform heat flux distribution is critical
- Most new process heaters today, particularly for West Coast and Gulf Coast
- Heater retrofits for Beat Available Control Technology (BACT) NOx reduction

**Callidus Ultra Low NOx Burner Models:**

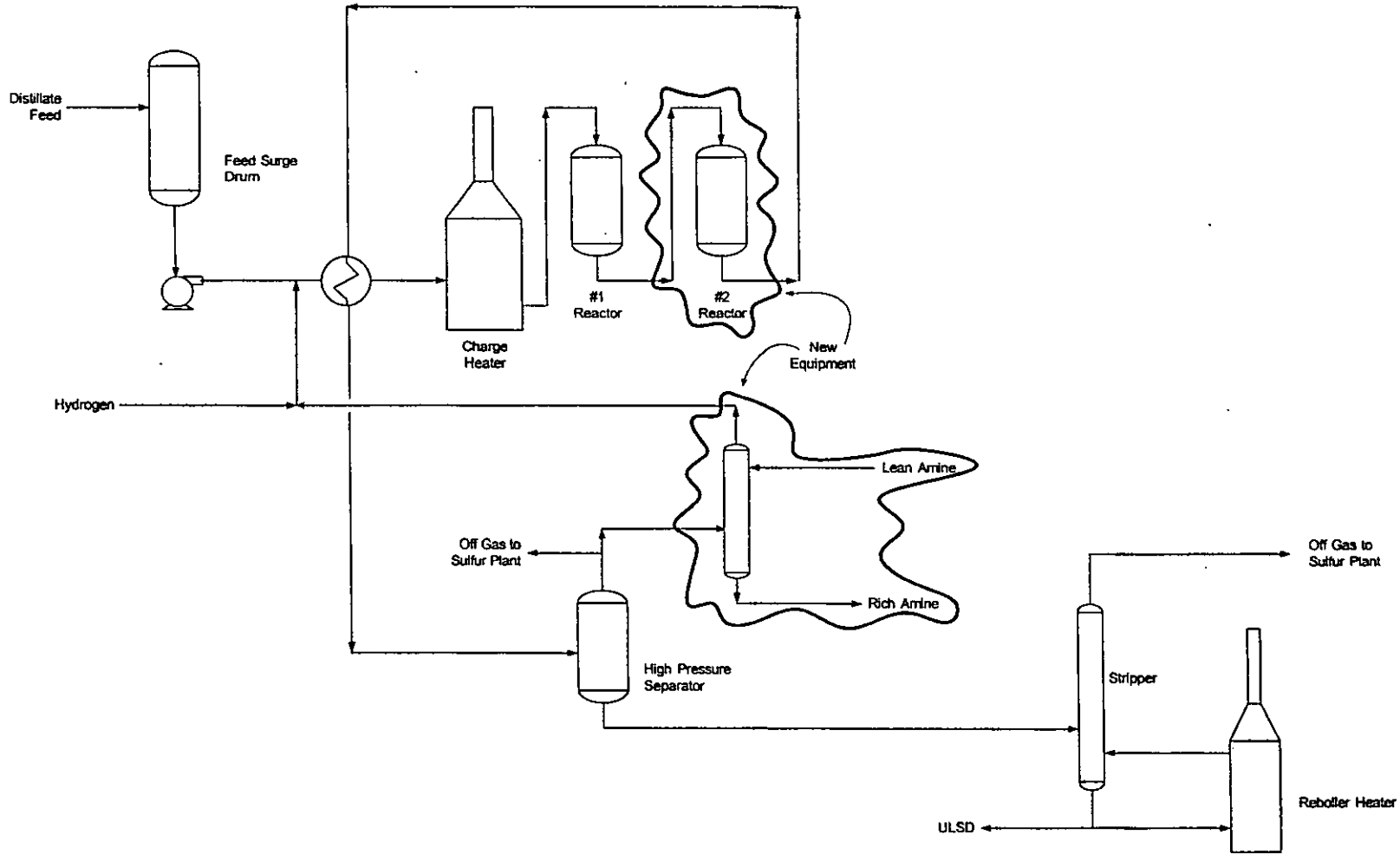
- **LE-CSG** (Low Emission Callidus Staged Gas)
- **LE-CRG** (Low Emission Callidus Raw Gas)




ATC S-37-118-0
S-37-119-0

ATC S-37-77-10

ATC S-37-122-0

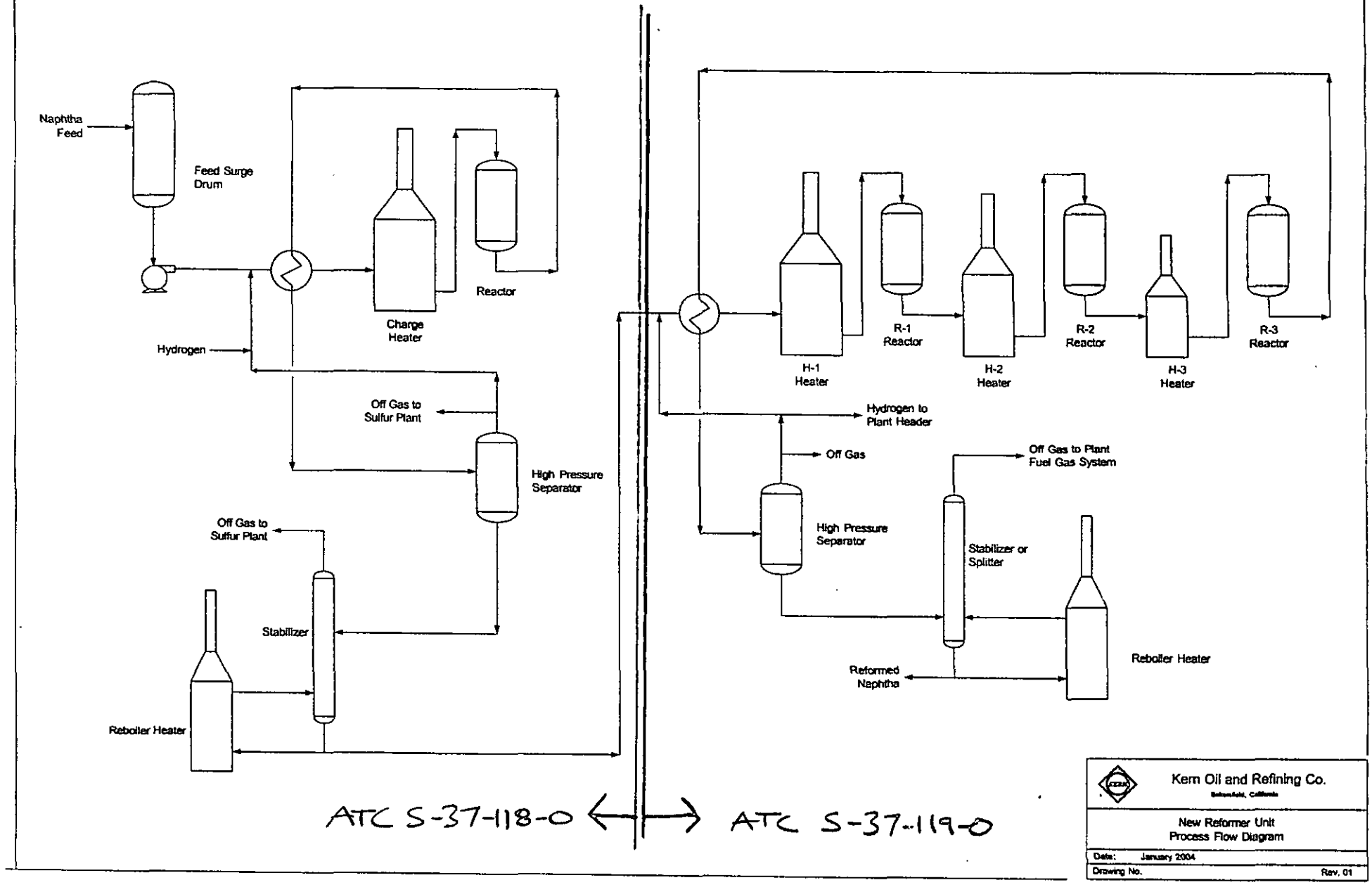


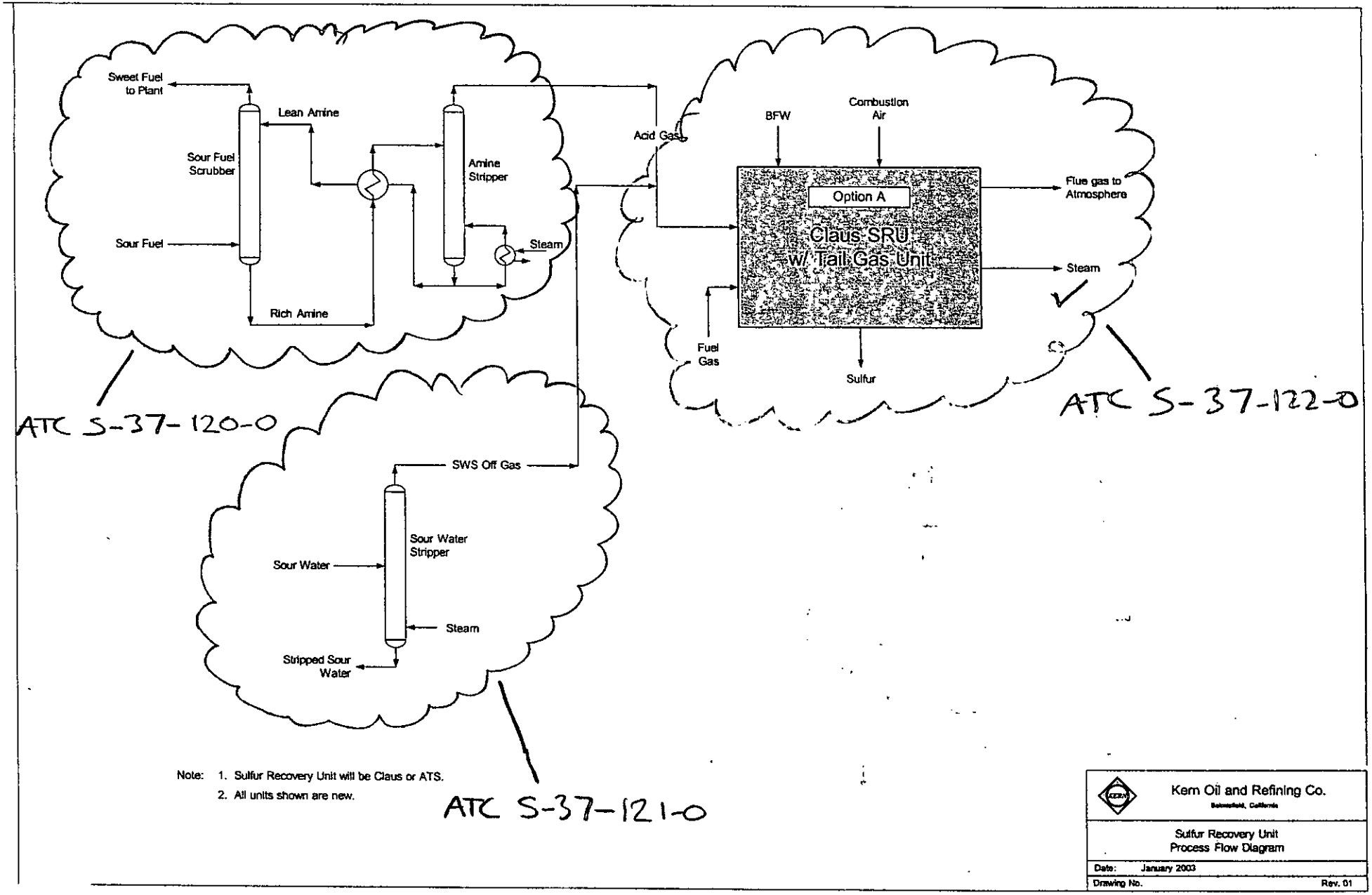

Kern Oil and Refining Co.
Bakersfield, California

DHT Unit
Process Flow Diagram

Date: January 2004

Drawing No. Rev. 01


Naphtha Feed
Feed Surge Drum
Charge Heater
Reactor
Hydrogen
Off Gas to Sulfur Plant
High Pressure Separator
Off Gas to Sulfur Plant
Stabilizer
Reboiler Heater
H-1 Heater
R-1 Reactor
H-2 Heater
R-2 Reactor
H-3 Heater
R-3 Reactor
Hydrogen to Plant Header
Off Gas
Off Gas to Plant Fuel Gas System
High Pressure Separator
Stabilizer or Splitter
Reboiler Heater
Reformed Naphtha
ATC S-37-118-0
ATC S-37-119-0
Kern Oil and Refining Co.
Bakersfield, California
New Reformer Unit
Process Flow Diagram
Date: January 2004
Drawing No.
Rev. 01




Note: 1. Sulfur Recovery Unit will be Claus or ATS.
2. All units shown are new.

| | |
|---|---|
| Kern Oil and Refining Co. Bakersfield, California | |
| Sulfur Recovery Unit Process Flow Diagram | |
| Date: | January 2003 |
| Drawing No. | Rev. 01 |

| KERN OIL & REFINING CO. - ULSD PROJECT<br>EXISTING DIESEL HYDROTREATER - ADDITIONAL/MODIFIED EQUIPMENT | |
|---|---|
| **EQUIPMENT** | **DESCRIPTION** |
| ***Vessels*** | Add Second Reactor<br><br>Add Inlet Distributors To Reactors<br><br>Add Recyle Gas Scrubber |
| ***Heaters*** | Upgrade Existing Feed Heater (Increase to 15.0 MMBtu/hr)<br><br>Upgrade Existing Stripper Reboiler Heater (Increase to 15.0 MMBtu/hr) |
| ***Pumps*** | |
| ***Compressors*** | |

**EQUIPMENT LIST FOR**
**NEW REFORMER (HYDROTREATER SECTION)**

1. ***Fired Heaters:***

   Charge (11.1 MMBtu/hr)
   Stripper Reboiler (~~18.9~~ 12.6 MMBtu/hr)

2. ***Heat Exchangers:***

   H.P. Feed/Effluent
   H.P. Effluent Cooler
   Stripper Product Cooler
   Stripper O.H. Cooler
   Stripper Bottoms/Feed

3. **Air Coolers:**

   H.P. Effluent Cooler
   Stripper O.H. Condenser
   Product Cooler

4. ***Vessels:***

   Reactor
   Feed Surge Drum
   Compressor Suction Drum
   High Pressure Separator
   Stripper Tower
   Stripper Overhead Accumulator

5. ***Compressors:***

   H2 Makeup (2)
   H2 Recycle (2)

6. ***Pumps:***

   Charge (2)
   Stripper Reflux (2)
   Stripper Reboiler (2)

7. ***Drains:***

   Unit Drains (20)

**EQUIPMENT LIST FOR**
**NEW REFORMER (REFORMER SECTION)**

***1. Fired Heaters:***

Charge 1 (25.7 MMBtu/hr)
Charge 2 (13.4 MMBtu/hr)
Charge 3 (8.9 MMBtu/hr)
Splitter Reboiler (8.3 MMBtu/hr)

***2. Heat Exchangers:***

H.P. Effluent Cooler
Splitter O.H. Cooler
Splitter Feed/Effluent
Splitter Product Cooler
Light Reformate Cooler
Side Stripper Reboiler Heater

***3. Air Coolers:***

H.P. Effluent Cooler
Splitter O.H. Cooler
Splitter Product Cooler
Light Reformate Cooler

***4. Vessels:***

Reactors (3)
Feed Surge Drum
Compressor Suction Drum
High Pressure Separator
Splitter Tower
Splitter Side Stripper
Splitter O.H. Accumulator

***5. Compressors:***

H2 Recycle (2)

***6. Pumps:***

Charge (2)
Splitter Reflux (2)
Splitter Reboiler (2)

***7. Drains:***

Section Drains (30)

| NEW AMINE SECTION EQUIPMENT LIST | DESCRIPTION |
|---|---|
| *Columns* | HP Amine Absorber<br>LP Amine Absorber<br>Amine Regenerator |
| *Vessels* | Rich Amine Flash Drum<br>Regenerator Overhead Accumulator<br>Reboiler Condensate Drum<br>Amine Sump<br>Amine Surge Drum |
| *Exchangers* | Lean Amine Cooler<br>Lean/Rich Amine Exchanger<br>Regenerator Reboiler<br>Regenerator Overhead Condenser |
| *Pumps* | Lean Amine Pump (2)<br>Lean Amine Booster Pump (2)<br>Regenerator Reflux Pump (2)<br>Amine Sump Pump (1) |
| *Filters* | Lean Amine Particle Filter<br>Lean Amine Carbon Filter<br>Lean Amine Post Carbon Filter<br>Drains (10) |

| KERN OIL & REFINING CO. - ULSD PROJECT<br>NEW SOUR WATER STRIPPING SECTION | |
|---|---|
| **EQUIPMENT** | **DESCRIPTION** |
| *Columns* | Stripper Tower |
| *Vessels* | Feed Drum<br>Steam Reboiler<br>Overhead Receiver |
| *Exchangers* | Effluent Coolers (4)<br>Bottoms Finfan |
| *Pumps* | Feed Pump (2)<br>Recovered Hydrocarbon Pump (2)<br>O.H.Reflux Pump (2) |
| *Drains* | Section Drains (6) |

| KERN OIL & REFINING CO.<br>NEW SULFUR RECOVERY UNIT | |
|---|---|
| **EQUIPMENT** | **DESCRIPTION** |
| ***Columns*** | Desuperheater/Contact Condensor |
| ***Vessels*** | Acid Gas K.O. Drum<br>Ammonia Gas K.O. Drum |
| ***Reactors*** | No. 1, No. 2, No. 3 Converter<br>& Hydrogenation Reactor |
| ***Exchangers*** | Waste Heat Boiler<br>No. 1 Condenser<br>No. 2 Condenser<br>No. 3 Condenser<br>No. 4 Condenser<br>No. 1 Reheater<br>No. 2 Reheater<br>No. 3 Reheater<br>Reactor Effluent Cooler<br>Contact Cond Air Cooler<br>Contact Cond Water Cooler |
| ***Furnaces*** | Reaction Furnace<br>Incinerator<br>Incinerator Stack<br>Reducing Gas Generator |
| ***Pumps*** | Acid Gas KO Drum Pump (2)<br>Ammonia Gas KO Drum Pump (2)<br>Sulfur Transfer Pump (2)<br>Desuperheater Circ. Pump (2)<br>Contact Condenser Circ. Pump (2) |
| ***Blowers*** | Combustion Air Blower (2) |
| ***Ejectors*** | Sulfur Pit Vent Eductor |
| ***Concrete Pits*** | Sulfur Pit |

# Exhibit V. San Joaquin Valley Air Pollution Control District, Final Authority to Construct, Application No. S-37-4-22 (Apr. 8, 2025)

# San Joaquin Valley
# Air Pollution Control District

# AUTHORITY TO CONSTRUCT

**PERMIT NO**: S-37-4-22 **ISSUANCE DATE**: 04/08/2025

**LEGAL OWNER OR OPERATOR**: KERN ENERGY
**MAILING ADDRESS**: 7724 E PANAMA LN
BAKERSFIELD, CA 93307-9210

**LOCATION**: PANAMA LN & WEEDPATCH HWY
BAKERSFIELD, CA 93307-9210

**SECTION**: 25 **TOWNSHIP**: 30S **RANGE**: 28E

**EQUIPMENT DESCRIPTION**:
MODIFICATION OF PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSOR:INSTALL CHLORIDE SCRUBBER AND REVISE EMISSION FACTORS USING CORRELATION EQUATION

## CONDITIONS

1. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit

2. Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit

3. Heaters shall be fired only on purchased commercial natural gas, refinery fuel gas, or any combination thereof. [District Rule 2201, 4001] Federally Enforceable Through Title V Permit

4. Sulfur content of fuel combusted in this unit shall not exceed 100 ppmv (as total reduced sulfur), based on a 3 hour rolling average. [District Rules 2201 and 40 CFR Part 60, Subpart J, 60.104(a)(1)] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

**YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT.** This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

**SIGNED**

Brian Clements, Director of Permit Services



Central Regional Office • 1990 E. Gettysburg Avenue • Fresno, California 93726 • (559) 230-5900 • Fax (559) 230-6061

5. All refinery fuel gas combusted in the heaters shall be monitored for H2S content by a continuous emissions monitoring (CEM) system. CEM shall be installed, calibrated, operated, and reported according to EPA guidelines as specified under 40 CFR 60, Subpart J, Specification 7, and general requirements. CEM results shall be calculated on a rolling three (3) hour basis. [District Rules 2201, 4001, Subpart J, 60.105(a)(4) and 60.105(a)(4)iii] Federally Enforceable Through Title V Permit

6. Permittee shall obtain and analyze a representative gas sample for total reduced sulfur of the fuel combusted in this unit at least once per year. Each sample shall be analyzed for the following reduced sulfur compounds: carbon disulfide, carbonyl sulfide, dimethyl disulfide, dimethyl sulfide, hydrogen sulfide and methyl mercaptan. For each sample, permittee shall record the analytical results for total sulfur, calculated as the sum of the results for all analytes, expressed as H2S, and shall calculate and record the ratio of total sulfur to H2S. Samples shall be analysed using ASTM D6228-98, or an alternative analytical method approved in advance by the APCO. [District Rule 2201] Federally Enforceable Through Title V Permit

7. The permittee shall demonstrate continuous compliance with the sulfur content limit (as total reduced sulfur) of the fuel combusted in this unit by calculation, as the product of the fuel H2S concentration and the ratio of total sulfur to H2S, based on the most recently conducted fuel sample analysis for total sulfur. The total sulfur of the fuel shall be calculated for each one hour H2S monitoring result, and the hourly fuel sulfur values shall be averaged over a rolling three hour period to determine compliance. [District Rule 2201]

8. Emission rates from each heater, except during startup and shutdown, shall not exceed any of the following: NOx (as NO2): 25 ppmv @ 3% O2 or 0.030 lb/MMBtu, VOC: 5.5 lb/MMscf, PM10: 7.6 lb/MMscf or CO: 50 ppmv @ 3% O2. [District Rules 2201, 2520, 4301, 4305, 4306, and 4351] Federally Enforceable Through Title V Permit

9. Particulate matter emissions shall not exceed 0.1 grain/dscf, 0.1 grain/dscf calculated to 12% CO2, nor 10 lb/hr. [District Rules 4201, 3.1 and 4301, 5.1 and 5.2.3] Federally Enforceable Through Title V Permit

10. Daily combustion emissions from this permit unit shall not exceed any of the following: NOx (as NO2): 42.6 lb/day, VOC: 7.8 lb/day, PM10: 10.8 lb/day, or CO: 52.5 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

11. The duration of each startup and shutdown period for each heater shall not exceed 12 hours and 9 hours respectively. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit

12. The permittee shall record the date and the duration of each startup and each shutdown. [District Rules 4305 and 4306]

13. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4351] Federally Enforceable Through Title V Permit

14. If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

15. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

16. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

17. Heater exhaust stacks shall be equipped with adequate provisions facilitating the collection of gas samples consistent with EPA Test Methods. [District Rule 1081] Federally Enforceable Through Title V Permit

18. Source testing to demonstrate compliance with NOx and CO emission limits shall be conducted not less than once every 12 months, except as provided below. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

19. Source testing to demonstrate compliance with NOx and CO emission limits shall be conducted not less than once every 36 months if compliance is demonstrated on two consecutive annual tests. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

20. If permittee fails any compliance demonstration for NOx or CO emission limits when testing not less than once every 36 months, compliance with NOx and CO emission limits shall be demonstrated not less than once every 12 months. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

21. Compliance demonstration (source testing) shall be by District witnessed, or authorized, sample collection by ARB certified testing laboratory. [District Rule 1081] Federally Enforceable Through Title V Permit

22. Compliance source testing shall be conducted under conditions representative of normal operation. [District Rule 1081] Federally Enforceable Through Title V Permit

23. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit

24. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

25. The following test methods shall be used unless otherwise approved by the APCO and EPA: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or ARB Method 100, and stack gas oxygen - EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

26. All required source testing shall conform to the compliance testing procedures described in District Rule 1081. [District Rule 1081] Federally Enforceable Through Title V Permit

27. Copies of all fuel invoices, gas purchase contracts, supplier certifications, and test results used to determine compliance with the conditions of this permit shall be maintained. The operator shall record daily amount and type(s) of fuel(s) combusted and all dates on which unit is fired on any noncertified fuel. [District Rule 2520, 9.4.2 and 40 CFR 60.48c(g)] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

28. The operator shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.5.2] Federally Enforceable Through Title V Permit

29. Nitrogen oxide (NOx) emission concentrations in ppmv shall be referenced at dry stack gas conditions, and shall be calculated to 3.00 percent by volume stack gas oxygen and averaged over 60 minutes, and lb/MMBtu rates shall be calculated as lb NO2/MMBtu of heat input (hhv). [District Rule 4305, 5.0, 8.2 and/or 4351, 8.1] Federally Enforceable Through Title V Permit

30. Draeger tubes shall be used as an alternative method for measuring fuel gas H2S during scheduled maintenance or unscheduled interruptions of CEMs. Draeger tube use shall be limited to no more than 96 continuous hours and fuel gas H2S shall be checked a minimum of every two hours during scheduled maintenance or unscheduled interruptions of CEMs. Alternate method of measuring fuel gas H2S shall occur no more than 192 hours in any calendar year. [40CFR60.13(i)] Federally Enforceable Through Title V Permit

31. Operator shall maintain all records of the reason for alternative monitoring and required fuel gas H2S monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

32. Pursuant to Rule 4320, beginning in 2010 the operator shall pay an annual emission fee to the District for NOx emissions from this unit for the previous calendar year. Payments are due by July 1 of each year. Payments shall continue annually until either the unit is permanently removed from service in the District or the operator demonstrates compliance with the applicable NOx emission limit listed in Rule 4320. [District Rule 4320]

33. Permittee shall maintain records of annual heat input (MMBtu) for this unit on a calendar year basis. Such records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and Rule 4320]

34. VOC emission rate from fugitive components associated with this emissions unit shall not exceed 9.8 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

35. Permit holder shall maintain accurate component count and resultant emissions according to California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, CAPCOA/CARB Table IV-3a: CAPCOA -Revised 1995 EPA Protocol Refinery Correlation Equations. Permit holder shall update such records when new components are approved and installed. [District Rule 2201] Federally Enforceable Through Title V Permit

36. Permit unit shall comply with applicable District Rule 4001 (NSPS, Subpart GGG) requirements on facility wide permit S-37-0. [District Rule 4001] Federally Enforceable Through Title V Permit

37. This unit is subject to Rule 4455 Leak Detection and Repair Conditions on the facility wide permit S-37-0. [District Rule 4455] Federally Enforceable Through Title V Permit

38. Permit unit shall comply with applicable District Rule 4001 (NSPS, Subpart GGG) requirements. [District Rule 4001] Federally Enforceable Through Title V Permit

39. Permittee shall comply with all applicable testing, recordkeeping, and reporting requirements specified in Rule 4001 - New Source Performance Standards, including but not limited to Subparts A and J. [District Rule 4001] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

40. Operators shall not depressurize any vessel containing VOCs unless the process unit turnaround is accomplished by employing one of the following operating procedures: The organic vapors shall either be recovered, added to the refinery fuel gas system and combusted; or controlled and piped to an appropriate firebox or incinerated for combustion; or flared, until the pressure within the process vessel is as close to atmospheric pressure as is possible. All process vessels shall be depressurized into the control facilities to less than 1020 mm Hg (5 psig) before venting/opening to atmosphere. All organic compounds which emerge from a refinery process vessel during the purging of said vessel and which otherwise would be emitted to the atmosphere shall be either directed to a flare or incinerator or shall be used for fuel until such disposition of emissions is not technically feasible or is less safe than atmospheric venting. [District Rule 4454, 4.0] Federally Enforceable Through Title V Permit

# Exhibit W. San Joaquin Valley Air Pollution Control District, Proposed Authority to Construct, Application No. S-37-4-22 (Feb. 19, 2025)

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

February 19, 2025

Mr. Gabe Castro
Kern Energy
7724 E Panama Lane
Bakersfield, CA 93307

**Re: Proposed Authority to Construct/Certificate of Conformity (Minor Mod)**
**District Facility # S-37**
**Project # S-1233158**

Dear Mr. Castro:

Enclosed for your review is the District's analysis of an application for Authority to Construct for the facility identified above. You requested that a Certificate of Conformity with the procedural requirements of 40 CFR Part 70 be issued with this project. The project is to install a chloride scrubber vessel and associated piping to remove chlorides from the refinery produced hydrogen stream.

After addressing all comments made during the 45-day EPA comment period, the District intends to issue the Authority to Construct with a Certificate of Conformity. Prior to operating with modifications authorized by the Authority to Construct, the facility must submit an application to modify the Title V permit as an administrative amendment, in accordance with District Rule 2520, Section 11.5.

If you have any questions, please contact Mr. Erin Scott, Permit Services Manager, at (661) 392-5500.

Thank you for your cooperation in this matter.

Sincerely,

Brian Clements
Director of Permit Services

Enclosures

cc: EPA Region 9 Air Permitting Manager (w/enclosure) via EPS

**Samir Sheikh**
Executive Director/Air Pollution Control Officer

**Northern Region**
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

**Central Region (Main Office)**
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

**Southern Region**
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: (661) 392-5500 FAX: (661) 392-5585

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# San Joaquin Valley Air Pollution Control District

## Authority to Construct Application Review

| | | | |
|---|---|---|---|
| Facility Name: | Kern Energy | Date: | September 24, 2024 |
| Mailing Address: | 7724 E Panama Lane<br>Bakersfield, CA 93307 | Engineer: | Dan Klevann |
| | | Lead Engineer: | Erin Scott |
| Facility Contact Person: | Gabe Castro | | |
| Contact Telephone: | 661-845-0761 | | |
| Contact E-Mail: | gcastro@kernenergy.com | | |
| Application #(s): | S-37-4-22 | | |
| Project #: | S-1233158 | | |
| Date Deemed Complete: | July 10, 2024 | | |

### I. Proposal

The primary business of Kern Energy (Kern) is a petroleum refining operation producing gasoline and other various petroleum distillates. Kern has submitted an Authority to Construct (ATC) application to install a chloride scrubber vessel and associated piping to remove chlorides from the refinery produced hydrogen stream. They have also requested to use revised emission factors for both the existing components and the new components based on the California Implementation Guidelines for Estimating Mass Emissions of fugitive Hydrocarbon Leaks at Petroleum Facilities, CAPCOA/CARB Table IV-3a: CAPCOA -Revised 1995 EPA Protocol Refinery Correlation Equations. Finally, due to implementation order of ATC's, permit S-37-4-20 inadvertently removed previously implemented changes. This project will correct the removal and the facility wide permit S-37-0-4 will be updated for continued compliance with the most recent version of Rule 4455. The updated facility wide permit is also attached.

Kern received their Title V Permit on January 31, 2003. This modification can be classified as a Title V minor modification pursuant to Rule 2520, and can be processed with a Certificate of Conformity (COC). Since the facility has specifically requested that this project be processed in that manner, the 45-day EPA comment period will be satisfied prior to the issuance of the Authority to Construct. Kern must apply to administratively amend their Title V permit.

### II. Applicable Rules

| | |
|---|---|
| Rule 2201 | New and Modified Stationary Source Review Rule (4/20/23) |
| Rule 2410 | Prevention of Significant Deterioration (6/16/11) |
| Rule 2520 | Federally Mandated Operating Permits (6/20/24) |
| Rule 4001 | New Source Performance Standards (4/14/99) |
| Rule 4002 | National Emissions Standards for Hazardous Air Pollutants (5/20/04) |
| Rule 4101 | Visible Emissions (2/17/05) |
| Rule 4102 | Nuisance (12/17/92) |
| Rule 4455 | Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants (6/15/23) |

CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

## III. Project Location

The facility is located at 7724 East Panama Lane in Bakersfield, CA. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

## IV. Process Description

Kern operates a petroleum refining operation engaged in the production of gasoline and various petroleum distillates, including diesel fuel. Kern proposes to install a chloride scrubber in order to remove chlorides from the hydrogen stream before it enters the fuel gas system and other hydrogen required processes. The removal of chlorides from the gas will decrease risk of corrosion to downstream equipment.

The chloride scrubber will be designed to process the hydrogen gas downstream of the catalytic platformer and reformer.

## V. Equipment Listing

Pre-Project Equipment Description:

S-37-4-20: PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSORS

Proposed Modification:

Install a chloride scrubber skid with connections to the platformer unit and reformer unit.

S-37-4-22: MODIFICATION OF PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSORS: INSTALL CHLORIDE SCRUBBER AND REVISE EMISSION FACTORS USING CORRELATION EQUATION

Post-Project Equipment Description:

S-37-4-22: PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS, CHLORIDE SCRUBBER SKID, AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSORS

## VI. Emission Control Technology Evaluation

Fugitive component counts are expected to increase with the installation of the chloride scrubber skid. VOC emissions from fugitive components are and will continue to be minimized with an inspection, maintenance, and repair program consistent with applicable District Rule 4455.

## VII. General Calculations

### A. Assumptions

- Facility will operate 24 hours per day, 7 days per week, and 52 weeks per year.
- There will be no change in combustion emissions associated with permit S-37-4.
- S-37-4 heaters are not being modified therefore NSR requirements of BACT, offsets, and public notice are not applicable to the heaters. No calculations will be performed for the S-37-4 heaters. Criteria emissions from the heaters will be stated for inclusion in the PAS emissions profiles.
- Fugitive emissions calculations below are for the new components.
- Facility has asked to calculate emissions using the EPA Protocol Refinery Correlation Equations for both pre-project emissions and post project emissions as allowed by District policy APR-1110 Revised Generally Accepted Emission Factors Fugitive emissions based on the following component counts.
- Pre-project Component count:
  Valves: 1,030, Pump Seals: 12, Others: 172, Connectors: 4,672, Flanges: 1,016, Open End Line :0
- Post-project Component count:
  Valves: 1,075, Pump Seals: 12, Others: 179, Connectors: 4,701, Flanges: 1,023, Open End Line :0

- Applicant supplied component counts, % default zeros, % pegged, and correlation screening values as below.

| Equipment Type | % Default Zero | % Pegged >10,000 ppm | Correlation Screening Value (ppm) |
|---|---|---|---|
| Valves | 95% | 0.0025% | 400 |
| Pump Seals | 95% | 0.0025% | 500 |
| Others | 95% | 0.0025% | 500 |
| Connectors | 95% | 0.0025% | 400 |
| Flanges | 95% | 0.0025% | 400 |

## B. Emission Factors

- The fugitive emissions from the equipment is calculated using California Implementation Guidelines for Estimating Mass Emissions of fugitive Hydrocarbon Leaks at Petroleum Facilities, CAPCOA/CARB Table IV-3a: CAPCOA -Revised 1995 EPA Protocol Refinery Correlation Equations. (see **Attachment F**)

## C. Calculations

### 1. Pre-Project Potential to Emit (PE1)

The current daily emissions from the fugitive emissions from the existing components and the existing combustion equipment is detailed below. The fugitives are calculated from previous component counts for the operation.

Combustion emissions, from current Permit limits:

| **PE1 Combustion Equipment** | | |
|---|---|---|
| **Pollutant** | **Daily Emissions (lb/day)** | **Annual Emissions (lb/year)** |
| NOx | 42.6 | 15,549 |
| SOx | 25.9 | 9,454 |
| PM10 | 10.8 | 3,942 |
| CO | 52.5 | 19,163 |
| VOC | 7.8 | 2,847 |

PE existing Fugitive components, from current permit limit:
VOC = 9.6 lb/day, 3,519 lb/yr

| Permit Total PE1 Combustion + Fugitives | | |
|---|---|---|
| **Pollutant** | **Daily Emissions (lb/day)** | **Annual Emissions (lb/year)** |
| NOx | 42.6 | 15,549 |
| SOx | 25.9 | 9,454 |
| PM10 | 10.8 | 3,942 |
| CO | 52.5 | 19,163 |
| VOC | 17.4 | 6,366 |

## 2. Post-Project Potential to Emit (PE2)

No changes are being made to the current daily emissions from the fugitive emissions from the existing components and the existing combustion equipment. The fugitives are calculated from previous component counts for the operation.

The new chloride scrubber fugitive emissions are calculated based on the new fugitive components that are being installed. The fugitive emissions from the equipment are calculated using California Implementation Guidelines for Estimating Mass Emissions of fugitive Hydrocarbon Leaks at Petroleum Facilities, CAPCOA/CARB Table IV-3a: CAPCOA -Revised 1995 EPA Protocol Refinery Correlation Equations. (see Attachment II)

Combustion emissions, from current Permit limits:

| PE2 Combustion equipment | | |
|---|---|---|
| **Pollutant** | **Daily Emissions (lb/day)** | **Annual Emissions (lb/year)** |
| NOx | 42.6 | 15,549 |
| SOx | 25.9 | 9,454 |
| PM10 | 10.8 | 3,942 |
| CO | 52.5 | 19,163 |
| VOC | 7.8 | 2,847 |

PE2 Fugitive components:
VOC = 9.8 lb/day, 3,571 lb/yr

| Permit total PE2 Combustion + Fugitives | | |
|---|---|---|
| **Pollutant** | **Daily Emissions (lb/day)** | **Annual Emissions (lb/year)** |
| NOx | 42.6 | 15,549 |
| SOx | 25.9 | 9,454 |
| PM10 | 10.8 | 3,942 |
| CO | 52.5 | 19,163 |
| VOC | 17.5 | 6,418 |

### 3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site, including all ERCs held as certificates and all emission reduction credits sold or transferred.

Facility emissions are already above the Offset and Major Source Thresholds for VOC emissions; therefore, SSPE1 calculations are not necessary.

### 4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source, except for emissions units proposed to be shut down as part of a Stationary Source Project, and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site, including all ERCs held as certificates and all emission reduction credits sold or transferred.

Since facility emissions are already above the Offset and Major Source Thresholds for VOC emissions, SSPE2 calculations are not necessary.

### 5. Major Source Determination

**Rule 2201 Major Source Determination:**

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status, the following shall NOT be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months), pursuant to the Clean Air Act, Title 3, Section 302, US Codes 7602(j) and (z)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 70.2

This source is an existing Major Source for VOC emissions and will remain a Major Source for VOC. No change in other pollutants is proposed or expected as a result of this project.

**Rule 2410 (Prevention of Significant Deterioration) Major Source Determination:**

The facility or the equipment evaluated under this project is listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 100 tpy for any regulated NSR pollutant.

| PSD Major Source Determination (tons/year) | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_2$ | VOC | $SO_2$ | CO | PM* | PM10 |
| Estimated Facility PE before Project Increase | 60 | 136 | 33 | 200 | 20 | 20 |
| PSD Major Source Thresholds | 100 | 100 | 100 | 100 | 100 | 100 |
| PSD Major Source? | N | Y | N | Y | N | N |

*PM assumed to be equal to PM10.

As shown above, the facility is an existing PSD major source for at least one pollutant.

## 6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the Quarterly Net Emissions Change (QNEC), and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since the chloride scrubber is a new emissions unit, BE = PE1 = 0 for all pollutants.

## 7. Senate Bill 288 Major Modification

A Senate Bill (SB) 288 Major Modification is a federal major modification under 40 CFR 51.165 as it existed on December 19, 2002. 40 CFR Part 51.165 (12/19/02) defines a Major Modification as any physical change in or change in the method of operation of *an*

*existing major stationary source* that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

Pursuant to District Policy APR 1130, this project does not trigger an SB288 Major Modification since the total project annual emission increase (Σ [PE2 – PE1] for all units in the project) averages less than or equal to 0.5 lb/day and is therefore rounded to zero for the purposes of triggering NSR requirements. However, to minimize future rounding errors, the figures are presented in the EE and in the permit without rounding the daily increase in emissions to zero.

## 8. Federal Major Modification / New Major Source

### Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

As defined in 40 CFR 51.165, Section (a)(1)(v) and part D of Title I of the CAA, a Federal Major Modification is any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act. The significant net emission increase threshold for each criteria pollutant is included in Rule 2201.

Pursuant to District Policy APR 1130, this project does not trigger a Federal Major Modification since the total project annual emission increase (Σ [PE2 – PE1] for all units in the project) averages less than or equal to 0.5 lb/day and is therefore rounded to zero for the purposes of triggering NSR requirements. However, to minimize future rounding errors, the figures are presented in the EE and in the permit without rounding the daily increase in emissions to zero.

**New Major Source**

As demonstrated above, this facility is not becoming a Major Source as a result of this project, therefore, this facility is not a New Major Source pursuant to Section 3.30 of District Rule 2201.

**9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination**

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination are listed in CFR 52.21 (b) (23). This project only affects VOC emissions which do not require a PSD evaluation per CFR 52.21(b)(23). No further discussion is required.

**10. Quarterly Net Emissions Change (QNEC)**

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix D.

## VIII. Compliance Determination

### Rule 2201 New and Modified Stationary Source Review Rule

**A. Best Available Control Technology (BACT)**

**1. BACT Applicability**

Pursuant to District Rule 2201, Section 4.1, BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding 2.0 pounds per day, or the relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding 2.0 pounds per day,
b. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2.0 pounds per day, and/or
c. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

New and Modified Source Review (NSR) addresses requirements such as Best Available Control Technology (BACT), offsets and public notice. This project is an NSR modification under Rule 2201 § 3.29.1.4. However, District Policy APR 1130 states:

"*District policy is to consider an increase in potential emissions of less than 0.5 lb/day to be rounded to zero for the purposes of triggering NSR requirements and therefore the requirements are not triggered.*"

The installation of the chloride scrubber has a potential to emit increase of 0.2 lb VOC/day. Therefore, Rule 2201 does not require BACT, offsets, and public notice under District Policy APR 1130.

## B. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

DELs for the emission units in this project will be included on the ATCs in the form of fugitive component emissions limits in lb VOC/day. The permittee will be required to maintain accurate records of fugitive component counts and resulting emission calculations to validate the DEL.

***Proposed Rule 2201 (DEL) Conditions:***

- VOC emission rate from fugitive components associated with this emissions unit shall not exceed 9.8 lb/day. [District Rule 2201]

## C. Compliance Assurance

### 1. Source Testing

Pursuant to District Policy APR 1705, source testing is not required to demonstrate compliance with Rule 2201.

### 2. Monitoring

Kern currently has a fugitive emission monitoring program in place. The new fugitive components will be monitored under the same program.

### 3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following condition(s) are listed on the permit to operate:

- Permit holder shall maintain accurate component count and resultant emissions from the components associated with this permit according to California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, CAPCOA/CARB Table IV-3a: CAPCOA -Revised 1995 EPA Protocol Refinery Correlation Equations. Permit holder shall update such records when new components are approved and installed. [District Rule 2201] Y

**4. Reporting**

No reporting is required to demonstrate compliance with Rule 2201.

**Rule 2410 Prevention of Significant Deterioration**

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination are listed in CFR 52.21 (b) (23). This project only affects VOC emissions which do not require a PSD evaluation per CFR 52.21(b)(23). No further discussion is required.

**Rule 2520 Federally Mandated Operating Permits**

This facility is subject to this Rule, and has received their Title V Operating Permit. The proposed modification is a Minor Modification to the Title V Permit.

In accordance with Rule 2520, Minor Permit Modifications are permit modifications that:

1. Do not violate requirements of any applicable federally enforceable local or federal requirement;
2. Do not relax monitoring, reporting, or recordkeeping requirements in the permit and are not significant changes in existing monitoring permit terms or conditions;
3. Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;
4. Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:
   a. A federally enforceable emission cap assumed to avoid classification as a modification under any provisions of Title I of the Federal Clean Air Act; and
   b. An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Federal Clean Air Act; and
5. Are not Title I modifications as defined in District Rule 2520 or modifications as defined in section 111 or 112 of the Federal Clean Air Act; and
6. Do not seek to consolidate overlapping applicable requirements;
7. Do not grant or modify a permit shield.

Additionally, Section 11.4 requires a description of the proposed change, the emissions resulting from the change, any new applicable requirements that will apply if the change occurs, suggested draft permits, compliance certification and an EPA 45-day review period of the proposed permit modification (or a shorter period if EPA has notified the District that EPA will not object to issuance of the permit modification, whichever is first).

As discussed above, the facility has applied for a Certificate of Conformity (COC) and the District will forward to EPA, for a 45-day review period, this application review which includes the proposed modified Title V permit [i.e. proposed ATC(s)] and the compliance certification form which demonstrates compliance with the minor permit modification requirements in Section 11.4. Therefore, the facility must apply to modify their Title V permit with an administrative amendment, prior to operating with the proposed modifications. The following conditions will be placed on the ATC.

- This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Y

- Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520] Y

Continued compliance with this rule is expected. The facility may construct/operate under the ATC upon submittal of the Title V administrative amendment application.

**Rule 4001 New Source Performance Standards (NSPS)**

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

**40 CFR Part 60, Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after January 4, 1983, and on or Before November 7, 2006**

Kern has an inspection and repair program for the components at the refinery. The program is in compliance with subpart GGG.

**40 CFR Part 60 Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006.**

Kern has stated that the installation of the chloride scrubber is to provide process improvements and stability to the hydrogen gas streams and reduce equipment corrosion/damage. The additional components being installed do not constitute a capital expenditure as defined in the subpart. As such, the project is not a modification under the subpart and no further discussion is required.

## Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

### 40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

This subpart applies to petroleum refining process units and to related emissions points that are specified in paragraphs (c)(1) through (9) of this section that are located at a plant site that: (1) are located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act; and (2) emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in table 1 of this subpart.

A major source is a facility that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year. Kern has previously submitted verification that the facility is not a major source of HAP, and the facility's total stationary source HAP emissions are limited by a permit condition of the facility-wide permit S-37-0 to 10 tons in any consecutive 12 month period any HAP (as defined in 40 CFR 63.2) and 25 tons in any consecutive 12 month period of any combination of HAPs. Therefore, the facility is not subject to the requirements of this rule.

## Rule 4101 Visible Emissions

Rule 4101 states that no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). Visible emissions are not expected from the scrubber or its fugitive components. Therefore, compliance with this rule is expected.

## Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

### California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification of an existing source shall not result in an increase in cancer risk greater than the District's significance level (20 in a million) and shall not result in acute and/or chronic risk indices greater than 1.

An HRA is not required for a project with a total facility prioritization score of less than or equal to one. According to the Technical Services Memo for this project, the total facility prioritization score including this project was less than or equal to one.

The resulting prioritization score for this project is shown below.

| Health Risk Assessment Summary | |
|---|---|
| | **Worst Case Potential** |
| **Prioritization Score** | 0.0 |

In accordance with District policy APR 1905, no further analysis is required to determine the impact from this project and compliance with the District's Risk Management Policy is expected.

Compliance with District Rule 4102 requirements is expected.

See Appendix C: Health Risk Assessment Summary

**Rule 4455 Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants**

The purpose of this rule is to limit Volatile Organic Compound (VOC) emissions from leaking components at petroleum refineries, gas liquids processing facilities, and chemical plants. This rule shall apply to components containing or contacting VOC at petroleum refineries, gas liquids processing facilities, and chemical plants.

The operator has implemented an operator management plan for the refinery for the current roster of components in VOC service. As required by this rule, the operator management plan submitted by the permittee was reviewed and approved by the District. The essential requirement of the rule is that an operator not use any component that leaks in excess of the applicable leak criteria established by the rule, with the exception that leaking components may be used provided that they are identified with a tag for repair, are repaired, or are awaiting re-inspection after being repaired, within the applicable time period specified in this rule. Minor and major gas and liquid leaks are defined and leak standards are established for the following component types: flanges, valves, threaded connections, pumps, compressor, pressure relief devices, pipes and other. The rule establishes inspection, re-inspection and maintenance requirements for components.

Condition 38 references facility wide permit conditions (S-37-0-4 conditions 102 through 136) that will ensure continued compliance with the rule.

**California Health & Safety Code 42301.6 (School Notice)**

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

### California Environmental Quality Act (CEQA)

As demonstrated in this evaluation, the project will not result in any significant impacts; therefore, the project is exempt per the common sense exemption that CEQA applies only to projects that have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

### Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), an indemnification agreement (IA) and/or a letter of credit (LOC) may be required. The decision to require an IA and/or an LOC is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an IA and/or an LOC will not be required for this project.

## IX. Recommendation

Compliance with all applicable rules and regulations is expected. Issue ATC S-37-4-22 subject to the permit conditions on the attached draft ATC in Appendix A**.**

## X. Billing Information

| Annual Permit Fees | | | |
|---|---|---|---|
| **Permit Number** | **Fee Schedule** | **Fee Description** | **Annual Fee** |
| S-37-4-22 | 3020-02-H | 59.1 MMBtu/hr | $1,238 |

## XI. Appendices

A*:* Draft ATC
B: Current PTO
C: HRA Summary
D: Quarterly Net Emissions Change
E: Compliance Certification
F: Emission Calculations

# APPENDIX A
## Draft ATC

# San Joaquin Valley
# Air Pollution Control District

**FACILITY:** S-37-0-4 **EXPIRATION DATE:** 08/31/2027

## FACILITY-WIDE REQUIREMENTS

1. The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1; County Rules 110 (San Joaquin); 109 (Merced)] Federally Enforceable Through Title V Permit
2. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0; County Rules 110 (San Joaquin); 109 (Merced)] Federally Enforceable Through Title V Permit
3. The owner or operator of any stationary source operation that emits more than 25 tons per year of nitrogen oxides or reactive organic compounds, shall provide the District annually with a written statement in such form and at such time as the District prescribes, showing actual emissions of nitrogen oxides and reactive organic compounds from that source. [District Rule 1160, 5.0] Federally Enforceable Through Title V Permit
4. Any person building, altering or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants, shall first obtain an Authority to Construct (ATC) from the District unless exempted by District Rule 2020 (12/20/07). [District Rule 2010, 3.0 and 4.0; and 2020] Federally Enforceable Through Title V Permit
5. The permittee must comply with all conditions of the permit including permit revisions originated by the District. All terms and conditions of a permit that are required pursuant to the Clean Air Act (CAA), including provisions to limit potential to emit, are enforceable by the EPA and Citizens under the CAA. Any permit noncompliance constitutes a violation of the CAA and the District Rules and Regulations, and is grounds for enforcement action, for permit termination, revocation, reopening and reissuance, or modification; or for denial of a permit renewal application. [District Rules 2070, 7.0; 2080; and 2520, 9.8.1 and 9.13.1] Federally Enforceable Through Title V Permit
6. A Permit to Operate or an Authority to Construct shall not be transferred unless a new application is filed with and approved by the District. [District Rule 2031] Federally Enforceable Through Title V Permit
7. Every application for a permit required under Rule 2010 (12/17/92) shall be filed in a manner and form prescribed by the District. [District Rule 2040] Federally Enforceable Through Title V Permit
8. The operator shall maintain records of required monitoring that include: 1) the date, place, and time of sampling or measurement; 2) the date(s) analyses were performed; 3) the company or entity that performed the analysis; 4) the analytical techniques or methods used; 5) the results of such analysis; and 6) the operating conditions at the time of sampling or measurement. [District Rule 2520, 9.4.1] Federally Enforceable Through Title V Permit
9. The operator shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, or report. Support information includes copies of all reports required by the permit and, for continuous monitoring instrumentation, all calibration and maintenance records and all original strip-chart recordings. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

FACILITY-WIDE REQUIREMENTS CONTINUE ON NEXT PAGE

10. The operator shall submit reports of any required monitoring at least every six months unless a different frequency is required by an applicable requirement. All instances of deviations from permit requirements must be clearly identified in such reports. [District Rule 2520, 9.5.1] Federally Enforceable Through Title V Permit

11. Deviations from permit conditions must be promptly reported, including deviations attributable to upset conditions, as defined in the permit. For the purpose of this condition, promptly means as soon as reasonably possible, but no later than 10 days after detection. The report shall include the probable cause of such deviations, and any corrective actions or preventive measures taken. All required reports must be certified by a responsible official consistent with section 10.0 of District Rule 2520 (6/21/01). [District Rules 2520, 9.5.2 and 1100, 7.0] Federally Enforceable Through Title V Permit

12. If for any reason a permit requirement or condition is being challenged for its constitutionality or validity by a court of competent jurisdiction, the outcome of such challenge shall not affect or invalidate the remainder of the conditions or requirements in that permit. [District Rule 2520, 9.7] Federally Enforceable Through Title V Permit

13. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. [District Rule 2520, 9.8.2] Federally Enforceable Through Title V Permit

14. The permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. [District Rule 2520, 9.8.3] Federally Enforceable Through Title V Permit

15. The permit does not convey any property rights of any sort, or any exclusive privilege. [District Rule 2520, 9.8.4] Federally Enforceable Through Title V Permit

16. The Permittee shall furnish to the District, within a reasonable time, any information that the District may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the District copies of records required to be kept by the permit or, for information claimed to be confidential, the permittee may furnish such records directly to EPA along with a claim of confidentiality. [District Rule 2520, 9.8.5] Federally Enforceable Through Title V Permit

17. The permittee shall pay annual permit fees and other applicable fees as prescribed in Regulation III of the District Rules and Regulations. [District Rule 2520, 9.9] Federally Enforceable Through Title V Permit

18. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to enter the permittee's premises where a permitted source is located or emissions related activity is conducted, or where records must be kept under condition of the permit. [District Rule 2520, 9.13.2.1] Federally Enforceable Through Title V Permit

19. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit. [District Rule 2520, 9.13.2.2] Federally Enforceable Through Title V Permit

20. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to inspect at reasonable times any facilities, equipment, practices, or operations regulated or required under the permit. [District Rule 2520, 9.13.2.3] Federally Enforceable Through Title V Permit

21. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or applicable requirements. [District Rule 2520, 9.13.2.4] Federally Enforceable Through Title V Permit

22. No air contaminants shall be discharged into the atmosphere for a period or periods aggregating more than 3 minutes in any one hour which is as dark or darker than Ringelmann #1 or equivalent to 20% opacity and greater, unless specifically exempted by District Rule 4101 (02/17/05). If the equipment or operation is subject to a more stringent visible emission standard as prescribed in a permit condition, the more stringent visible emission limit shall supersede this condition. [District Rule 4101, and County Rules 401 (in all eight counties in the San Joaquin Valley)] Federally Enforceable Through Title V Permit

FACILITY-WIDE REQUIREMENTS CONTINUE ON NEXT PAGE

23. No person shall manufacture, blend, repackage, supply, sell, solicit or apply any architectural coating with a VOC content in excess of the corresponding limit specified in Table1 or Table 2 of District Rule 4601 (4/16/20) for use or sale within the District. [District Rule 4601, 5.1] Federally Enforceable Through Title V Permit

24. All VOC-containing materials subject to Rule 4601 (4/16/20) shall be stored in closed containers when not in use. [District Rule 4601, 5.4] Federally Enforceable Through Title V Permit

25. The permittee shall comply with all the Labeling and Test Methods requirements outlined in Rule 4601 sections 6.1 and 6.3 (4/16/20). [District Rule 4601, 6.1 and 6.3] Federally Enforceable Through Title V Permit

26. With each report or document submitted under a permit requirement or a request for information by the District or EPA, the permittee shall include a certification of truth, accuracy, and completeness by a responsible official. [District Rule 2520, 9.13.1 and 10.0] Federally Enforceable Through Title V Permit

27. If the permittee performs maintenance on, or services, repairs, or disposes of appliances, the permittee shall comply with the standards for Recycling and Emissions Reduction pursuant to 40 CFR Part 82, Subpart F. [40 CFR 82 Subpart F] Federally Enforceable Through Title V Permit

28. If the permittee performs service on motor vehicles when this service involves the ozone-depleting refrigerant in the motor vehicle air conditioner (MVAC), the permittee shall comply with the standards for Servicing of Motor Vehicle Air Conditioners pursuant to all the applicable requirements as specified in 40 CFR Part 82, Subpart B. [40 CFR Part 82, Subpart B] Federally Enforceable Through Title V Permit

29. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8021] Federally Enforceable Through Title V Permit

30. Outdoor handling, storage and transport of any bulk material which emits dust shall comply with the requirements of District Rule 8031, unless specifically exempted under Section 4.0 of Rule 8031 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8031] Federally Enforceable Through Title V Permit

31. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8041] Federally Enforceable Through Title V Permit

32. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8051] Federally Enforceable Through Title V Permit

33. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8061] Federally Enforceable Through Title V Permit

34. Any unpaved vehicle/equipment area that anticipates more than 50 Average annual daily Trips (AADT) shall comply with the requirements of Section 5.1.1 of District Rule 8071. Any unpaved vehicle/equipment area that anticipates more than 150 vehicle trips per day (VDT) shall comply with the requirements of Section 5.1.2 of District Rule 8071. On each day that 25 or more VDT with 3 or more axles will occur on an unpaved vehicle/equipment traffic area, the owner/operator shall comply with the requirements of Section 5.1.3 of District Rule 8071. On each day when a special event will result in 1,000 or more vehicles that will travel/park on an unpaved area, the owner/operator shall comply with the requirements of Section 5.1.4 of District Rule 8071. All sources shall comply with the requirements of Section 5.0 of District Rule 8071 unless specifically exempted under Section 4.0 of Rule 8071 (9/16/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8071] Federally Enforceable Through Title V Permit

35. Any owner or operator of a demolition or renovation activity, as defined in 40 CFR 61.141, shall comply with the applicable inspection, notification, removal, and disposal procedures for asbestos containing materials as specified in 40 CFR 61.145 (Standard for Demolition and Renovation). [40 CFR 61 Subpart M] Federally Enforceable Through Title V Permit

FACILITY-WIDE REQUIREMENTS CONTINUE ON NEXT PAGE

36. The permittee shall submit certifications of compliance with the terms and standards contained in Title V permits, including emission limits, standards and work practices, to the District and the EPA annually (or more frequently as specified in an applicable requirement or as specified by the District). The certification shall include the identification of each permit term or condition, the compliance status, whether compliance was continuous or intermittent, the methods used for determining the compliance status, and any other facts required by the District to determine the compliance status of the source. [District Rule 2520, 9.16] Federally Enforceable Through Title V Permit

37. The permittee shall submit an application for Title V permit renewal to the District at least six months, but not greater than 18 months, prior to the permit expiration date. [District Rule 2520, 5.2] Federally Enforceable Through Title V Permit

38. When a term is not defined in a Title V permit condition, the definition in the rule cited as the origin and authority for the condition in a Title V permits shall apply. [District Rule 2520, 9.1.1] Federally Enforceable Through Title V Permit

39. Compliance with permit conditions in the Title V permit shall be deemed in compliance with the following outdated SIP requirements: Rule 401 (Madera, Fresno, Kern, Kings, San Joaquin, Stanislaus, Tulare and Merced), Rule 110 (San Joaquin), Rule 109 (Merced), and Rule 202 (Fresno, Kern, Tulare, Kings, Madera, Stanislaus, Merced, San Joaquin). A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

40. Compliance with permit conditions in the Title V permit shall be deemed in compliance with the following applicable requirements: SJVUAPCD Rules 1100, sections 6.1 and 7.0 (12/17/92); 2010, sections 3.0 and 4.0 (12/17/92); 2031 (12/17/92); 2040 (12/17/92); 2070, section 7.0 (12/17/92); 2080 (12/17/92); 4101 (2/17/05); 4601 (4/16/20); 8021 (8/19/2004); 8031 (8/19/2004); 8041 (8/19/2004); 8051 (8/19/2004); 8061 (8/19/2004); and 8071 (9/16/2004). A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

41. The reporting periods for the Report of Required Monitoring and the Compliance Certification Report begin January 1 of each year, unless alternative dates are approved by the District Compliance Division. These reports are due within 30 days of the end of the reporting period. [District Rule 2520] Federally Enforceable Through Title V Permit

42. 40 CFR 60 SUBPART GGG CONDITION: The owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in Subpart GGG. In doing so the owner or operator shall comply with the requirements of 40 CFR 60.484. [40 CFR 60.592(c)] Federally Enforceable Through Title V Permit

43. 40 CFR 60 SUBPART GGG CONDITION: Each Subpart GGG pump in light liquid service (PLLS) shall be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485(b), except as provided in 40 CFR 60.482-1(c) and 40 CFR 60.482-2(d), (e), and (f). Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal. A leak is detected if an instrument reading of 10,000 ppm or greater is measured or if there are indications of liquids dripping from the pump seal. [40 CFR 60.482-2(a) and (b)] Federally Enforceable Through Title V Permit

44. 40 CFR 60 SUBPART GGG CONDITION: When a leak is detected for each PLLS, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR 60.482-9. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. [40 CFR 60.482-2(c)] Federally Enforceable Through Title V Permit

45. 40 CFR 60 SUBPART GGG CONDITION: Any Subpart GGG PLLS equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of 40 CFR 60.482-2(a) provided the requirements specified in 40 CFR 60.482-2(d)(1) through (6) are met. [40 CFR 60.482(d)] Federally Enforceable Through Title V Permit

46. 40 CFR 60 SUBPART GGG CONDITION: Any Subpart GGG PLLS that is designated, as described in 40 CFR 60.486(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR 60.482-2(a), (c), and (d) if the pump meets the requirements specified in 40 CFR 60.482-2(e)(1), (2), and (3). [40 CFR 60.482-2(e)] Federally Enforceable Through Title V Permit

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47. 40 CFR 60 SUBPART GGG CONDITION: If any Subpart GGG PLLS is equipped with a closed vent system capable of capturing and transporting leakage from the seal or seals to a control device that complies with the requirements of 40 CFR 60.482-10, it is exempt from the requirements of 40 CFR 60.482-2(a) through (e). [40 CFR 60.482-2(f)] Federally Enforceable Through Title V Permit

48. 40 CFR 60 SUBPART GGG CONDITION: Any Subpart GGG pump in PLLS that is designated, as described in 40 CFR 60.486(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of 40 CFR 60.482-2(a) and 40 CFR 60.482-2(d)(4) through (6) if: 1). The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR 60.482-2(a); and 2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in 40 CFR 60.482-2(c) if a leak is detected. [40 CFR 60.482-2(g)] Federally Enforceable Through Title V Permit

49. 40 CFR 60 SUBPART GGG CONDITION: Except during pressure releases, each Subpart GGG pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR 60.485(c). [40 CFR 60.482-4(a)] Federally Enforceable Through Title V Permit

50. 40 CFR 60 SUBPART GGG CONDITION: After each pressure release, the Subpart GGG pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in 40 CFR 60.482-9. No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR 60.485(c). [40 CFR 60.482-4(b)] Federally Enforceable Through Title V Permit

51. 40 CFR 60 SUBPART GGG CONDITION: Any Subpart GGG pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in 40 CFR 60.482-10 is exempted from the requirements of 40 CFR 60.482-4(a) and (b). [40 CFR 60.482-4(c)] Federally Enforceable Through Title V Permit

52. 40 CFR 60 SUBPART GGG CONDITION: Any pressure relief device that is equipped with a rupture disk upstream of the Subpart GGG pressure relief device is exempt from the 40 CFR 60.482-4(a) and (b), provided the owner or operator complies with the requirements in 40 CFR 60.482-4(d)(2) of this section. After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in 40 CFR 60.482-9. [40 CFR 60.482-4(d)] Federally Enforceable Through Title V Permit

53. 40 CFR 60 SUBPART GGG CONDITION: Except for in-situ sampling systems and sampling systems without purges, each Subpart GGG sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in 40 CFR 60.482-1(c). Each closed-purge, closed-loop, or closed-vent system shall comply with the requirements specified in 40 CFR 60.482-5(b)(1), (2), (3), and (4). [40 CFR 60.482-5(a), (b), and (c)] Federally Enforceable Through Title V Permit

54. 40 CFR 60 SUBPART GGG CONDITION: Each Subpart GGG open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR 60.482-1(c). The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with this condition at all other times. [40 CFR 60.482-6(a) and (c)] Federally Enforceable Through Title V Permit

55. 40 CFR 60 SUBPART GGG CONDITION: Each Subpart GGG open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. [40 CFR 60.482-6(b)] Federally Enforceable Through Title V Permit

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56. 40 CFR 60 SUBPART GGG CONDITION: Subpart GGG open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of 40 CFR 60.482-6(a), (b) and (c). [40 CFR 60.482-6(d)] Federally Enforceable Through Title V Permit

57. 40 CFR 60 SUBPART GGG CONDITION: Subpart GGG open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in 40 CFR 60.482-6(a) through (c) are exempt from the requirements of 40 CFR 60.482-6(a) through (c). [40 CFR 60.482-6(e)] Federally Enforceable Through Title V Permit

58. 40 CFR 60 SUBPART GGG CONDITION: Each Subpart GGG valve in gas/vapor service and in light liquid service shall be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485(b) and shall comply with 40 CFR 60.482-7(b) through (e), except as provided in 40 CFR 60.482-7(f), (g), and (h), 40 CFR 60.483-1, 40 CFR 60.483-2, and 40 CFR 60.482-1(c). A leak is detected if an instrument reading of 10,000 ppm or greater is measured. [40 CFR 60.482-7(a) and (b)] Federally Enforceable Through Title V Permit

59. 40 CFR 60 SUBPART GGG CONDITION: Any Subpart GGG valve in gas/vapor service or in light liquid service for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected. If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months. [40 CFR 60.482-7(c)] Federally Enforceable Through Title V Permit

60. 40 CFR 60 SUBPART GGG CONDITION: When a leak is detected for any Subpart GGG valve in gas/vapor service or in light liquid service, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in 40 CFR 60.482-9. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the best practices specified in 40 CFR 60.482-7(e)(1), (2), (3), and (4), where practicable. [40 CFR 60.482-7(d) and (e)] Federally Enforceable Through Title V Permit

61. 40 CFR 60 SUBPART GGG CONDITION: Any Subpart GGG valve in gas/vapor service or in light liquid service that is designated, as described in 40 CFR 60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR 60.482-7(a) if the valve meets the requirements specified in 40 CFR 60.482-7(f)(1), (2), and (3). [40 CFR 60.482-7(f)] Federally Enforceable Through Title V Permit

62. 40 CFR 60 SUBPART GGG CONDITION: Any Subpart GGG valve in gas/vapor service or in light liquid service that is designated, as described in 40 CFR 60.486(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of 40 CFR 60.482-7(a) if: 1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR 60.482-7(a); and 2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times. [40 CFR 60.482-7(g)] Federally Enforceable Through Title V Permit

63. 40 CFR 60 SUBPART GGG CONDITION: Any Subpart GGG valve in gas/vapor service or in light liquid service that is designated, as described in 40 CFR 60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of 40 CFR 60.482-7(a) if: 1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface; 2) The process unit within which the valve is located either becomes an affected facility through 40 CFR 60.14 or 40 CFR 60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult-to-monitor; and 3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year. [40 CFR 60.482-7(h)] Federally Enforceable Through Title V Permit

64. 40 CFR 60 SUBPART GGG CONDITION: The owner or operator may elect to comply with the applicable provisions for Subpart GGG valves in gas/vapor service and in light liquid service as specified in 40 CFR 60.483-1 and 60.483-2. [40 CFR 60.592(b)] Federally Enforceable Through Title V Permit

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65. 40 CFR 60 SUBPART GGG CONDITION: If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and Subpart GGG valves in heavy liquid service, Subpart GGG pressure relief devices in light liquid or heavy liquid service, and Subpart GGG connectors, the owner or operator shall follow either one of the following procedures: 1) The owner or operator shall monitor the equipment within 5 days by the method specified in 40 CFR 60.485(b) and shall comply with the requirements of 40 CFR 60.482-8(b) through (d); or 2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak. A leak is detected if an instrument reading of 10,000 ppm or greater is measured. [40 CFR 60.482-8(a) and (b)] Federally Enforceable Through Title V Permit

66. 40 CFR 60 SUBPART GGG CONDITION: When a leak is detected in Subpart GGG pumps and valves in heavy liquid service, Subpart GGG pressure relief devices in light liquid or heavy liquid service, and Subpart GGG connectors, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR 60.482-9. The first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the best practices described under 40 CFR 60.482-7(e). [40 CFR 60.482-8(c) and (d)] Federally Enforceable Through Title V Permit

67. 40 CFR 60 SUBPART GGG CONDITION: Delay of Subpart GGG leak repair will be allowed if the repair is technologically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Delay of repair is allowed for equipment which is isolated from the process and which does not remain in VOC service. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown. [40 CFR 60.482-9(a)(b)(e)] Federally Enforceable Through Title V Permit

68. 40 CFR 60 SUBPART GGG CONDITION: Delay of Subpart GGG leak repair for valves will be allowed if the owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair and when repair procedures are effected and when repair procedures ar effected, the purged material is collected and destroyed or recovered in a control device complying with 40 CFR 60.482-10. Delay of leak repair for pumps will be allowed if the repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and repair is completed as soon as practicable, but no later than 6 months after the leak was detected. [40 cfr 60.482-9(c)(d)] Federally Enforceable Through Title V Permit

69. 40 CFR 60 SUBPART GGG CONDITION: For Subpart GGG closed vent systems and control devices, vapor recovery systems shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, whichever is less stringent. [40 CFR 60.482-10(b)] Federally Enforceable Through Title V Permit

70. 40 CFR 60 SUBPART GGG CONDITION: For Subpart GGG closed vent systems and control devices, enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 degrees C. [40 CFR 60.482-10(c)] Federally Enforceable Through Title V Permit

71. 40 CFR 60 SUBPART GGG CONDITION: Except as provided in 40 CFR 60.482-10(i) through (k), each Subpart GGG closed vent system used to comply with the provisions of Subpart GGG shall be inspected according to the procedures and schedule specified in 40 CFR 60.482-10(f)(1) and (f)(2). Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in 40 CFR 60.482-10(h). A first attempt at repair shall be made no later than 5 calendar days after the leak is detected. Repair shall be completed no later than 15 calendar days after the leak is detected. [40 CFR 60.482-10(f) and (g)] Federally Enforceable Through Title V Permit

72. 40 CFR 60 SUBPART GGG CONDITION: Delay of repair of a Subpart GGG closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown. [40 CFR 60.482-10(h)] Federally Enforceable Through Title V Permit

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73. 40 CFR 60 SUBPART GGG CONDITION: If a Subpart GGG vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of 40 CFR 60.482-10(f)(1)(i) and (f)(2). [40 CFR 60.482-10(i)] Federally Enforceable Through Title V Permit

74. 40 CFR 60 SUBPART GGG CONDITION: Any parts of the Subpart GGG closed vent system that are designated, as described in 40 CFR 60.482-10(l)(1), as unsafe to inspect are exempt from the inspection requirements of 40 CFR 60.482-10(f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR 60.482-10 (j)(1) and (j)(2). [40 CFR 60.482-10(j)] Federally Enforceable Through Title V Permit

75. 40 CFR 60 SUBPART GGG CONDITION: Any parts of the Subpart GGG closed vent system that are designated, as described in 40 CFR 60.482-10(l)(2), as difficult to inspect are exempt from the inspection requirements of 40 CFR 60.482-10(f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR 60.482-10(k)(1) through (k)(3). [40 CFR 60.482-10(k)] Federally Enforceable Through Title V Permit

76. 40 CFR 60 SUBPART GGG CONDITION: The owner or operator shall record the following information: 1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment; 2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment; 3) For each inspection during which a leak is detected, a record of the information specified in 40 CFR 60.486(c); 4) For each inspection conducted in accordance with 40 CFR 60.485(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected; and 5) For each visual inspection conducted in accordance with 40 CFR 60.482-10(f)(1)(ii) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected. [40 CFR 60.482-10(l)] Federally Enforceable Through Title V Permit

77. 40 CFR 60 SUBPART GGG CONDITION: Closed vent systems and control devices used to comply with provisions Subpart GGG shall be operated at all times when emissions may be vented to them. [40 CFR 60.482-10(m)] Federally Enforceable Through Title V Permit

78. 40 CFR 60 SUBPART GGG CONDITION: In conducting the Subpart GGG performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in 40 CFR 60, Appendix A or other methods and procedures as specified in 40 CFR 60.485, except as provided in 40 CFR 60.8(b). [40 CFR 60.485(a)] Federally Enforceable Through Title V Permit

79. 40 CFR 60 SUBPART GGG CONDITION: The owner or operator shall determine compliance with the standards in 40 CFR 60.482, 60.483, and 60.484 as follows: Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used: (i) Zero air (less than 10 ppm of hydrocarbon in air); and (ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane. [40 CFR 60.485(b)] Federally Enforceable Through Title V Permit

80. 40 CFR 60 SUBPART GGG CONDITION: The owner or operator shall determine compliance with the no detectable emission standards in 40 CFR 60.482-2(e), 60.482-3(i), 60.482-4, 60.482-7(f), and 60.482-10(e) as follows: 1) The requirements of 40 CFR 60.485(b) shall apply. 2) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance. [40 CFR 60.485(c)] Federally Enforceable Through Title V Permit

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81. 40 CFR 60 SUBPART GGG CONDITION: The owner or operator shall test each piece of Subpart GGG equipment unless demonstrated that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used: 1) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference as seen in 40 CFR 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment; 2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid; and 3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, the previous two procedures as specified in 40 CFR 60.485(d)(1) and (2) shall be used to resolve the disagreement. [40 CFR 60.485(d)] Federally Enforceable Through Title V Permit

82. 40 CFR 60 SUBPART GGG CONDITION: The owner or operator shall demonstrate that the Subpart GGG equipment is in light liquid service by showing that all the following conditions apply: 1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20 øC (1.2 in. H2O at 68 degrees F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference as seen in 40 CFR 60.17) shall be used to determine the vapor pressures; 2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20 degrees Celsius is equal to or greater than 20 percent by weight; and 3) The fluid is a liquid at operating conditions. [40 CFR 60.485(e)] Federally Enforceable Through Title V Permit

83. 40 CFR 60 SUBPART GGG CONDITION: Samples used in conjunction with 40 CFR 60.485(d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare. [40 CFR 60.485(f)] Federally Enforceable Through Title V Permit

84. 40 CFR 60 SUBPART GGG CONDITION: An owner or operator of more than one affected facility subject to the provisions Subpart GGG may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility. [40 CFR 60.486(a)] Federally Enforceable Through Title V Permit

85. 40 CFR 60 SUBPART GGG CONDITION: When each Subpart GGG leak is detected as specified in 40 CFR 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply: 1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment; 2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in 40 CFR 60.482-7(c) and no leak has been detected during those 2 months; and 3) The identification on equipment except on a valve, may be removed after it has been repaired. [40 CFR 60.486(b)] Federally Enforceable Through Title V Permit

86. 40 CFR 60 SUBPART GGG CONDITION: When each Subpart GGG leak is detected as specified in 40 CFR 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following information shall be recorded in a log and shall be kept for 5 years in a readily accessible location: 1) The instrument and operator identification numbers and the equipment identification number; 2) The date the leak was detected and the dates of each attempt to repair the leak; 3) Repair methods applied in each attempt to repair the leak; 4) ``Above 10,000" if the maximum instrument reading measured by the methods specified in 40 CFR 60.485(a) after each repair attempt is equal to or greater than 10,000 ppm; 5) ``Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak; 6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown; 7) The expected date of successful repair of the leak if a leak is not repaired within 15 days; 8) Dates of process unit shutdown that occur while the equipment is unrepaired; and 9) The date of successful repair of the leak. [40 CFR 60.486(c) and District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

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87. 40 CFR 60 SUBPART GGG CONDITION: The following information pertaining to the design requirements for Subpart GGG closed vent systems and control devices described in 40 CFR 60.482-10 shall be recorded and kept in a readily accessible location: 1) Detailed schematics, design specifications, and piping and instrumentation diagrams; 2) The dates and descriptions of any changes in the design specifications; 3) A description of the parameter or parameters monitored, as required in 40 CFR 60.482-10(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring; 4) Periods when the closed vent systems and control devices required in 40 CFR 60.482-2, 60.482-3, 60.482-4, and 60.482-5 are not operated as designed, including periods when a flare pilot light does not have a flame; and 5) Dates of startups and shutdowns of the closed vent systems and control devices required in 40 CFR 60.482-2, 60.482-3, 60.482-4, and 60.482-5. [40 CFR 60.486(d)] Federally Enforceable Through Title V Permit

88. 40 CFR 60 SUBPART GGG CONDITION: The following information pertaining to all equipment subject to the requirements in 40 CFR 60.482-1 to 60.482-10 shall be recorded in a log that is kept in a readily accessible location: 1) A list of identification numbers for equipment subject to the requirements of Subpart GGG; 2) (i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR 60.482-2(e), 60.482-3(i) and 60.482-7(f). (ii) The designation of equipment as subject to the requirements of 40 CFR 60.482-2(e), 60.482-3(i) and 60.482-7(f) shall be signed by the owner or operator; 3) A list of equipment identification numbers for pressure relief devices required to comply with 60.482-4; 4) (i) The dates of each compliance test as required in 40 CFR 60.482-2(e), 60.482-3(i), 60.482-4, and 60.482-7(f). (ii) The background level measured during each compliance test. (iii) The maximum instrument reading measured at the equipment during each compliance test; and 5) A list of identification numbers for equipment in vacuum service. [40 CFR 60.486(e)] Federally Enforceable Through Title V Permit

89. 40 CFR 60 SUBPART GGG CONDITION: The following information pertaining to all Subpart GGG valves subject to the requirements of 40 CFR 60.482-7(g) and (h) and to all Subpart GGG pumps subject to the requirements of 40 CFR 60.482-2(g) shall be recorded in a log that is kept in a readily accessible location: 1) A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump; and 2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve. [40 CFR 60.486(f)] Federally Enforceable Through Title V Permit

90. 40 CFR 60 SUBPART GGG CONDITION: The following information shall be recorded for Subpart GGG valves complying with 40 CFR 60.483-2: 1) A schedule of monitoring; 2) The percent of valves found leaking during each monitoring period. [40 CFR 60.486(g)] Federally Enforceable Through Title V Permit

91. 40 CFR 60 SUBPART GGG CONDITION: The following information shall be recorded in a log that is kept in a readily accessible location: 1) Design criterion required in 40 CFR 60.482-2(d)(5) and 60.482-3(e)(2) and explanation of the design criterion; and 2) Any changes to this criterion and the reasons for the changes. [40 CFR 60.486(h)] Federally Enforceable Through Title V Permit

92. 40 CFR 60 SUBPART GGG CONDITION: The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in 40 CFR 60.480(d): 1) An analysis demonstrating the design capacity of the affected facility; 2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol; and 3) An analysis demonstrating that equipment is not in VOC service. [40 CFR 60.486(i)] Federally Enforceable Through Title V Permit

93. 40 CFR 60 SUBPART GGG CONDITION: Information and data used to demonstrate that a piece of equipment is not in Subpart GGG VOC service shall be recorded in a log that is kept in a readily accessible location. [40 CFR 60.486(j)] Federally Enforceable Through Title V Permit

94. 40 CFR 60 SUBPART GGG CONDITION: The provisions of 40 CFR 60.7 (b) and (d) do not apply to affected facilities subject to Subpart GGG. [40 CFR 60.486(k)] Federally Enforceable Through Title V Permit

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95. 40 CFR 60 SUBPART GGG CONDITION: All Subpart GGG semiannual reports to the Administrator shall include the following information, summarized from the information in 40 CFR 60.486: 1) Process unit identification; 2) For each month during the semiannual reporting period, i) Number of valves for which leaks were detected as described in 40 CFR 60.482-7(b) or 40 CFR 60.483-2, (ii) Number of valves for which leaks were not repaired as required in 40 CFR 60.482-7(d)(1), (iii) Number of pumps for which leaks were detected as described in 40 CFR 60.482-2(b) and (d)(6)(i), (iv) Number of pumps for which leaks were not repaired as required in 40 CFR 60.482-2(c)(1) and (d)(6)(ii), (v) Number of compressors for which leaks were detected as described in 40 CFR 60.482-3(f), (vi) Number of compressors for which leaks were not repaired as required in 40 CFR 60.482-3(g)(1), and (vii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible; 3) Dates of process unit shutdowns which occurred within the semiannual reporting period; 4) Revisions to items reported in the semiannual report if changes have occurred since the initial report, as required in 40 CFR 60.487 (a) and (b), or subsequent revisions to the initial report. [40 CFR 60.487(c)] Federally Enforceable Through Title V Permit

96. 40 CFR 60 SUBPART GGG CONDITION: An owner or operator electing to comply with the provisions of 40 CFR 60.483-1 and 60.483-2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions. [40 CFR 60.487(d)] Federally Enforceable Through Title V Permit

97. 40 CFR 60 SUBPART GGG CONDITION: An owner or operator shall report the results of all performance tests in accordance with 40 CFR 60.8 of the General Provisions. The provisions of 40 CFR 60.8(d) do not apply to affected facilities subject to the provisions of Subpart GGG except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests. [40 CFR 60.487(e)] Federally Enforceable Through Title V Permit

98. 40 CFR 60 SUBPART GGG CONDITION: The Subpart GGG semiannual reporting requirements of 40 CFR 60.487(a), (b), and (c) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of 40 CFR 60.487(a), (b), and (c), provided that they comply with the requirements established by the State. [40 CFR 60.487(f)] Federally Enforceable Through Title V Permit

99. 40 CFR 60 SUBPART GGG CONDITION: Compressors are exempt from the standards of Subpart GGG if the owner or operator demonstrates that a compressor is in hydrogen service. Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E-260, E-168, or E-169 shall be used. An owner or operator may use engineering judgment to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures that conform to the general method described in ASTM E-260, E-168, or E-169 shall be used to resolve the disagreement. If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures that conform to the general method described in ASTM E-260, E-168, or E-169. [40 CFR 60.593(b)] Federally Enforceable Through Title V Permit

100. 40 CFR 60 SUBPART GGG CONDITION: For compliance with Subpart GGG, an owner or operator may use the following provision in addition to 40 CFR 60.485(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 øC as determined by ASTM Method D86-78, 82, 90, 95, or 96. [40 CFR 60.593(d)] Federally Enforceable Through Title V Permit

101. 40 CFR 60 SUBPART GGG CONDITION: Equipment that is in vacuum service is excluded from the requirements of 40 CFR 60.482-2 to 40 CFR 60.482-10 if it is identified as required in 40 CFR 60.486(e)(5). [40 CFR 60.482-1(d)] Federally Enforceable Through Title V Permit

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102. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Except for complying with the applicable requirements of Sections 6.1 and 7.2, the requirements of this rule shall not apply to 1) components subject to Rule 4623, 2) pressure relief devices, pumps, and compressors equipped with a closed vent system as defined in Section 3.0, 3) components buried below ground, 4) components exclusively handling liquid streams which have less than 10 percent by weight (<10 wt%) evaporation at 150 C, 5) components exclusively handling liquid streams with a VOC content less than ten percent by weight (<10 wt%), 6) components exclusively handling gas/vapor streams with a VOC content of less than one percent by weight (<1wt%), 7) components incorporated in lines exclusively in vacuum service, 8) components exclusively handling commercial natural gas. [District Rule 4455, 4.1 & 4.2] Federally Enforceable Through Title V Permit

103. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall not use any component that leaks in excess of the allowable leak standards of Rule 4455, or is found to be in violation of the provisions specified in Section 5.1.3. A component identified as leaking in excess of an allowable leak standard may be used provided it has been identified with a tag for repair, has been repaired, or is awaiting re-inspection after repair, within the applicable time period specified within the rule. [District Rule 4455, 5.1.1] Federally Enforceable Through Title V Permit

104. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere. [District Rule 4455, 5.1.2] Federally Enforceable Through Title V Permit

105. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall be in violation of Rule 4455 if any District inspection demonstrates that one or more of the conditions in Section 5.1.4 (Leak Standards) exist at the facility. [District Rule 4455, 5.1.3.1] Federally Enforceable Through Title V Permit

106. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Except for annual operator inspection described in Section 5.1.3.2.3, any operator inspection that demonstrates that one or more of the conditions in Section 5.1.4 exist at the facility shall not constitute a violation of Rule 4455 if the leaking components are repaired as soon as practicable but not later than the time frame specified in Rule 4455. Such components shall not be counted towards determination of compliance with the provisions of Section 5.1.4. [District Rule 4455, 5.1.3.2.1] Federally Enforceable Through Title V Permit

107. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Leaking components detected during operator inspection pursuant Section 5.1.3.2.1 that are not repaired, replaced, or removed from operation as soon as practicable but not later than the time frame specified in Rule 4455 shall be counted toward determination of compliance with the provisions of Section 5.1.4. [District Rule 4455, 5.1.3.2.2] Federally Enforceable Through Title V Permit

108. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Any operator inspection conducted annually for a component type (including operator annual inspections pursuant to Section 5.2.5, 5.2.6, 5.2.7, or 5.2.8) that demonstrates one or more of the conditions in Section 5.1.4 exist at the facility shall constitute a violation of Rule 4455 regardless of whether or not the leaking components are repaired, replaced, or removed from operation within the allowable repair time frame specified in Rule 4455. [District Rule 4455, 5.1.3.2.3] Federally Enforceable Through Title V Permit

109. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: A component shall be considered leaking if one or more of the conditions specified in Sections 5.1.4.1 through 5.1.4.4 of Rule 4455 exist at the facility. Readings shall be taken as methane using a portable hydrocarbon detection instrument and shall be made in accordance with the methods specified in Section 6.4.1 of Rule 4455. [District Rule 4455, 5.1.4] Federally Enforceable Through Title V Permit

110. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall audio-visually inspect for leaks all accessible operating pumps, compressors and Pressure Relief Devices (PRDs) in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. Any identified leak that cannot be immediately repaired shall be reinspected within 24 hours using a portable analyzer. If a leak is found, it shall be repaired as soon as practical but not later than the time frame specified in Table 3. [District Rule 4455, 5.2.1 & 5.2.2] Federally Enforceable Through Title V Permit

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111. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall inspect all components at least once every calendar quarter, except for inaccessible components, unsafe-to-monitor components and pipes. Inaccessible components, unsafe-to-monitor components and pipes shall be inspected in accordance with the requirements set forth in Sections 5.2.5, 5.2.6, and 5.2.7. New, replaced, or repaired fittings, flanges and threaded connections shall be inspected immediately after being placed into service. Components shall be inspected using EPA Method 21. [District Rule 4455, 5.2.3, 5.2.4, 5.2.5, 5.2.6 & 5.2.7] Federally Enforceable Through Title V Permit

112. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, provided the operator meets all the criteria specified in Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis. [District Rule 4455, 5.2.8] Federally Enforceable Through Title V Permit

113. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: An annual inspection frequency approved by the APCO shall revert to quarterly inspection frequency for a component type if either the operator inspection or District inspection demonstrates that a violation of the provisions of Sections 5.1, 5.2 and 5.3 of the rule exists for that component type, or the APCO issued a Notice of Violation for violating any of the provisions of Rule 4455 during the annual inspection period for that component type. When the inspection frequency changes from annual to quarterly inspections, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency, giving the reason(s) and date of change to quarterly inspection frequency. [District Rule 4455, 5.2.9 & 5.2.10] Federally Enforceable Through Title V Permit

114. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. To insure that the process PRD is operating properly, and is leak-free, the operator shall re-inspect the process PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release using EPA Method 21. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections. [District Rule 4455, 5.2.11] Federally Enforceable Through Title V Permit

115. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Except for process PRD, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using EPA Method 21. [District Rule 4455, 5.2.12] Federally Enforceable Through Title V Permit

116. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator. Any attempt by an operator to count such District inspections as part of the mandatory operator's inspections is considered to be willful circumvention and is a violation of this rule. [District Rule 4455, 5.2.13] Federally Enforceable Through Title V Permit

117. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag that contains the information specified in Section 5.3.3. The tag shall remain affixed to the component until the leaking component has been repaired or replaced; has been re-inspected using EPA Method 21; and is found to be in compliance with the requirements of Rule 4455. [District Rule 4455, 5.3.1 5.3.2 and 5.3.3] Federally Enforceable Through Title V Permit

118. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 4455, 5.3.4] Federally Enforceable Through Title V Permit

119. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: If the leak has been minimized but the leak still exceeds the applicable leak standards of Rule 4455, an operator shall repair or replace the leaking component, vent the leaking component to a closed vent system, or remove the leaking component from operation as soon as practicable but not later than the time period specified in Table 3. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Table 3, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required. [District Rule 4455, 5.3.5] Federally Enforceable Through Title V Permit

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120. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall minimize the leak within one hour after detection of the leak. If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of Rule 4455, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 4455 5.3.6] Federally Enforceable Through Title V Permit

121. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the requirements specified in Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6. [District Rule 4455, 5.3.7] Federally Enforceable Through Title V Permit

122. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall monitor process PRD by using electronic process control instrumentation that allows for real time continuous parameter monitoring or by using telltale indicators for the process PRD where parameter monitoring is not feasible. [District Rule 4455, 5.4.1] Federally Enforceable Through Title V Permit

123. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: After a release from a process PRD in excess of 500 pounds of VOC in a continuous 24-hour period, the operator shall immediately conduct a failure analysis and implement corrective actions as soon as practicable but not later than 30 days to prevent the reoccurrence of similar release. For refineries processing greater than 20,000 barrels of crude oil per day, any subsequent release in excess of 500 pounds of VOC within a continuous 24-hour period shall be subject to the requirements of Section 5.4.5. [District Rule 4455, 5.4.3 & 5.4.4] Federally Enforceable Through Title V Permit

124. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator of a refinery processing greater than 20,000 barrels of crude oil per day shall connect all process PRDs serving that process equipment to an APCO-approved closed vent system as defined in Section 3.0 if any of the conditions specified in Sections 5.4.5.1 and 5.4.5.2 occurs. Process PRDs subject to the provisions of Section 5.4.5 shall be connected to an APCO-approved closed-vent system as soon as practicable, but no later than the first turnaround after the requirement to connect becomes effective. [District Rule 4455, 5.4.5] Federally Enforceable Through Title V Permit

125. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: All major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator or District personnel to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but not later than 24 hours after discovery. The operator shall comply with the requirements of Sections 6.1.4 if there is any change in the description of major components or critical components. [District Rule 4455, 5.5.1 & 5.5.2] Federally Enforceable Through Title V Permit

126. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall keep a copy of the operator management plan at the facility and make it available to the APCO, ARB and US EPA upon request. By January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any changes to the existing, approved operator management plan. [District Rule 4455, 6.1.2 & 6.1.4] Federally Enforceable Through Title V Permit

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127. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall maintain an inspection log containing, at a minimum, 1) total number of components inspected, and total number and percentage of leaking components found by component types, 2) location, type, name or description of each leaking component, and description of any unit where the leaking component is found, 3) date of leak detection and method of leak detection, 4) for gaseous leaks, record the leak concentration in ppmv, and for liquid leaks record whether the leak is a major liquid leak or a minor liquid leak, 5) date of repair, replacement, or removal from operation of leaking components, 6) identification and location of essential component and critical components found leaking that cannot be repaired until the next process unit turnaround or not later one year after leak detection, whichever comes earlier, 7) methods used to minimize the leak from essential components and critical components that cannot be repaired until the next process unit turnaround or not later one year after leak detection, whichever comes earlier, 8) after the component is repaired or is replaced, the date of reinspection and the leak concentration in ppmv, 9) inspector's name, business mailing address, and business telephone number, and 10) the facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log. [District Rule 4455, 6.2.1] Federally Enforceable Through Title V Permit

128. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, analyzer reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4455, 6.2.3] Federally Enforceable Through Title V Permit

129. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall notify the APCO, by telephone or other methods approved by the APCO, of any process PRD release described in Sections 5.4.4 and 5.4.5, and any release in excess of the reportable quantity limits as stipulated in 40 CFR, Part 117, Part 302 and Part 355, including any release in excess of 100 pounds of VOC, within one hour of such occurrence or within one hour of the time said person knew or reasonably should have known of its occurrence. [District Rule 4455, 6.3.1] Federally Enforceable Through Title V Permit

130. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The operator shall submit a written report to the APCO within thirty (30) calendar days following a PRD release subject to 6.3.1. The written report shall include 1) process PRD type, size, and location, 2) date, time and duration of the process PRD release, 3) types of VOC released and individual amounts, in pounds, including supporting calculations, 4) cause of the process PRD release, and 5) corrective actions taken to prevent a subsequent process PRD release. [District Rule 4455 6.3.2] Federally Enforceable Through Title V Permit

131. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Copies of all records shall be retained for a minimum of five (5) years after the date of an entry. Such records shall be made available to the APCO, ARB, or US EPA upon request. [District Rule 4455, 6.2.2, 6.2.3 & 6.2.4] Federally Enforceable Through Title V Permit

132. RULE 4455 LEAK DETECTION AND REPAIR CONDITION:All leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Rule 4455. [District Rule 4455] Federally Enforceable Through Title V Permit

133. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Measurements of gaseous leak concentrations shall be conducted according to US EPA Method 21 using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with the procedures specified in US EPA Method 21 or the manufacturer's instruction, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. [District Rule 4455, 6.4.1] Federally Enforceable Through Title V Permit

134. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: The VOC content of exempt streams shall be determined using American Society of Testing and Materials (ASTM) D 1945 for gases and South Coast Air Quality Management District (SCAQMD) Method 304-91 for liquids. [District Rule 4455, 6.4.2] Federally Enforceable Through Title V Permit

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135. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: For exempt streams, the percent by volume liquid evaporated at 150 deg C shall be determined using ASTM D 86. [District Rule 4455, 6.4.3] Federally Enforceable Through Title V Permit

136. RULE 4455 LEAK DETECTION AND REPAIR CONDITION: Equivalent test methods other than specified in Sections 6.4.1 through 6.4.5 may be used provided such test methods have received prior approval from the US EPA, ARB, and APCO. [District Rule 4455, 6.4] Federally Enforceable Through Title V Permit

137. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of 40 CFR 60.482-3a for all equipment within 180 days of initial startup. [40 CFR 60.482-1a(a)] Federally Enforceable Through Title V Permit

138. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Compliance with 40 CFR 60.482-3a shall be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in 40 CFR 60.485a. [40 CFR 60.482-1a(b)] Federally Enforceable Through Title V Permit

139. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of 40 CFR 60.482-3a as provided in 40 CFR 60.484a. [40 CFR 60.482-1a(c)(1)] Federally Enforceable Through Title V Permit

140. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of 40 CFR 60.482-3a, an owner or operator shall comply with the requirements of that determination. [40 CFR 60.482-1a(c)(2)] Federally Enforceable Through Title V Permit

141. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Equipment that is in vacuum service is excluded from the requirements of 40 CFR 60.482-3a if it is identified as required in 40 CFR 60.486a(e)(5). [40 CFR 60.482-1a(d)] Federally Enforceable Through Title V Permit

142. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Unless exempt under 40 CFR 60.482-3a, each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in 40 CFR 60.482-3a(h) and (i). The barrier fluid system shall be in heavy liquid service or shall not be in VOC service. Each compressor shall be operated and equipped as specified in 40 CFR 60.482-3a(b)(1), (2), or (3). [40 CFR 60.482-3a(a), (b), and (c)] Federally Enforceable Through Title V Permit

143. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any compressor that is designated, as described in 40 CFR 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the requirements of 40 CFR 60.482-3a(a) through (h) if the compressor meets the requirements specified in 40 CFR 60.482-3a(i)(1) and (2). [40 CFR 60.482-3a(i), and District Rule 2201] Federally Enforceable Through Title V Permit

144. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any existing reciprocating compressor in a process unit which becomes an affected facility under the provisions of 40 CFR 60.14 or 40 CFR 60.15 is exempt from 40 CFR 60.482a(a), (b), (c), (d), (e), and (h), provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR 60.482-3a(a), (b), (c), (d), (e), and (h). [40 CFR 60.593a(c)] Federally Enforceable Through Title V Permit

145. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in Subpart GGGa. In doing so, the owner or operator shall comply with the requirements of 40 CFR 60.484a. [40 CFR 60.592a(c)] Federally Enforceable Through Title V Permit

146. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Each pump in light liquid service (PLLS) shall be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485a(b), except as provided in 40 CFR 60.482-1a(c) and 40 CFR 60.482-2a(d), (e), and (f). Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal. A leak is detected if an instrument reading of 2,000 ppm or greater is measured or if there are indications of liquids dripping from the pump seal. [40 CFR 60.482-2a(a) and (b)] Federally Enforceable Through Title V Permit

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147. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: When a leak is detected for each PLLS, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR 60.482-9a. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. [40 CFR 60.482-2a(c)] Federally Enforceable Through Title V Permit

148. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any PLLS equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of 40 CFR 60.482-2a(a) provided the requirements specified in 40 CFR 60.482-2a(d)(1) through (6) are met. [40 CFR 60.482a(d)] Federally Enforceable Through Title V Permit

149. Any PLLS that is designated, as described in 40 CFR 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR 60.482-2a(a), (c), and (d) if the pump meets the requirements specified in 40 CFR 60.482-2a(e)(1), (2), and (3). [40 CFR 60.482-2a(e)] Federally Enforceable Through Title V Permit

150. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: If any PLLS is equipped with a closed vent system capable of capturing and transporting leakage from the seal or seals to a control device that complies with the requirements of 40 CFR 60.482-10a, it is exempt from the requirements of 40 CFR 60.482-2a(a) through (e). [40 CFR 60.482-2a(f)] Federally Enforceable Through Title V Permit

151. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any pump in PLLS that is designated, as described in 40 CFR 60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of 40 CFR 60.482-2a(a) and 40 CFR 60.482-2a(d)(4) through (6) if: 1). The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR 60.482-2a(a); and 2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in 40 CFR 60.482-2a(c) if a leak is detected. [40 CFR 60.482-2a(g)] Federally Enforceable Through Title V Permit

152. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR 60.485a(c). [40 CFR 60.482-4a(a)] Federally Enforceable Through Title V Permit

153. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in 40 CFR 60.482-9a. No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR 60.485a(c). [40 CFR 60.482-4a(b)] Federally Enforceable Through Title V Permit

154. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in 40 CFR 60.482-10a is exempted from the requirements of 40 CFR 60.482-4a(a) and (b). [40 CFR 60.482-4a(c)] Federally Enforceable Through Title V Permit

155. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the 40 CFR 60.482-4a(a) and (b), provided the owner or operator complies with the requirements in 40 CFR 60.482-4a(d)(2) of this section. After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in 40 CFR 60.482-9a. [40 CFR 60.482-4a(d)] Federally Enforceable Through Title V Permit

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156. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Except for in-situ sampling systems and sampling systems without purges, each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in 40 CFR 60.482-1a(c). Each closed-purge, closed-loop, or closed-vent system shall comply with the requirements specified in 40 CFR 60.482-5a(b)(1), (2), (3), and (4). [40 CFR 60.482-5a(a), (b), and (c)] Federally Enforceable Through Title V Permit

157. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR 60.482-1a(c), (d) and (e). The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with this condition at all other times. [40 CFR 60.482-6a(a) and (c)] Federally Enforceable Through Title V Permit

158. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. [40 CFR 60.482-6a(b)] Federally Enforceable Through Title V Permit

159. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of 40 CFR 60.482-6a(a), (b) and (c). [40 CFR 60.482-6a(d)] Federally Enforceable Through Title V Permit

160. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in 40 CFR 60.482-6a(a) through (c) are exempt from the requirements of 40 CFR 60.482-6a(a) through (c). [40 CFR 60.482-6a(e)] Federally Enforceable Through Title V Permit

161. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Each valve in gas/vapor service and in light liquid service shall be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485a(b) and shall comply with 40 CFR 60.482-7a(b) through (e), except as provided in 40 CFR 60.482-7a(f), (g), and (h), 40 CFR 60.483-1a, 40 CFR 60.483-2a, and 40 CFR 60.482-1a(c) and (f). A leak is detected if an instrument reading of 500 ppm or greater is measured. [40 CFR 60.482-7(a) and (b)] Federally Enforceable Through Title V Permit

162. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any valve in gas/vapor service or in light liquid service for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected. If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months. [40 CFR 60.482-7a(c)] Federally Enforceable Through Title V Permit

163. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: When a leak is detected for any valve in gas/vapor service or in light liquid service, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in 40 CFR 60.482-9a. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the best practices specified in 40 CFR 60.482-7a(e)(1), (2), (3), and (4), where practicable. [40 CFR 60.482-7a(d) and (e)] Federally Enforceable Through Title V Permit

164. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any valve in gas/vapor service or in light liquid service that is designated, as described in 40 CFR 60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR 60.482-7a(a) if the valve meets the requirements specified in 40 CFR 60.482-7a(f)(1), (2), and (3). [40 CFR 60.482-7a(f)] Federally Enforceable Through Title V Permit

165. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any valve in gas/vapor service or in light liquid service that is designated, as described in 40 CFR 60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of 40 CFR 60.482-7a(a) if: 1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR 60.482-7a(a); and 2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times. [40 CFR 60.482-7a(g)] Federally Enforceable Through Title V Permit

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166. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any valve in gas/vapor service or in light liquid service that is designated, as described in 40 CFR 60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of 40 CFR 60.482-7a(a) if: 1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface; 2) The process unit within which the valve is located either becomes an affected facility through 40 CFR 60.14 or 40 CFR 60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult-to-monitor; and 3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year. [40 CFR 60.482-7a(h)] Federally Enforceable Through Title V Permit

167. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The owner or operator may elect to comply with the applicable provisions for valves in gas/vapor service and in light liquid service as specified in 40 CFR 60.483-1a and 60.483-2a. [40 CFR 60.592a(b)] Federally Enforceable Through Title V Permit

168. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, the owner or operator shall follow either one of the following procedures: 1) The owner or operator shall monitor the equipment within 5 days by the method specified in 40 CFR 60.485a(b) and shall comply with the requirements of 40 CFR 60.482-8a(b) through (d); or 2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak. A leak is detected if an instrument reading of 10,000 ppm or greater is measured. [40 CFR 60.482-8a(a) and (b)] Federally Enforceable Through Title V Permit

169. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: When a leak is detected in pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR 60.482-9a. The first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the best practices described under 40 CFR 60.482-2a(c)(2) or 40 CFR 60.482-7a(e). [40 CFR 60.482-7a(e)] Federally Enforceable Through Title V Permit

170. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Delay of leak repair will be allowed if the repair is technologically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Delay of repair is allowed for equipment which is isolated from the process and which does not remain in VOC service. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown. [40 CFR 60.482-9a(a)(b)(e)] Federally Enforceable Through Title V Permit

171. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Delay of leak repair for valves will be allowed if the owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair and when repair procedures are effected and when repair procedures ar effected, the purged material is collected and destroyed or recovered in a control device complying with 40 CFR 60.482-10a. Delay of leak repair for pumps will be allowed if the repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and repair is completed as soon as practicable, but no later than 6 months after the leak was detected. [40 cfr 60.482-9a(c)(d)] Federally Enforceable Through Title V Permit

172. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: For closed vent systems and control devices, vapor recovery systems shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, whichever is less stringent. [40 CFR 60.482-10a(b)] Federally Enforceable Through Title V Permit

173. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: For closed vent systems and control devices, enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 degrees C. [40 CFR 60.482-10a(c)] Federally Enforceable Through Title V Permit

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174. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Except as provided in 40 CFR 60.482-10a(i) through (k), each closed vent system used to comply with the provisions of Subpart GGGa shall be inspected according to the procedures and schedule specified in 40 CFR 60.482-10a(f)(1) and (f)(2). Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in 40 CFR 60.482-10a(h). A first attempt at repair shall be made no later than 5 calendar days after the leak is detected. Repair shall be completed no later than 15 calendar days after the leak is detected. [40 CFR 60.482-10a(f) and (g)] Federally Enforceable Through Title V Permit

175. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown. [40 CFR 60.482-10a(h)] Federally Enforceable Through Title V Permit

176. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of 40 CFR 60.482-10a(f)(1)(i) and (f)(2). [40 CFR 60.482-10a(i)] Federally Enforceable Through Title V Permit

177. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any parts of the closed vent system that are designated, as described in 40 CFR 60.482-10a(l)(1), as unsafe to inspect are exempt from the inspection requirements of 40 CFR 60.482-10a(f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR 60.482-10a (j)(1) and (j)(2). [40 CFR 60.482-10a(j)] Federally Enforceable Through Title V Permit

178. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Any parts of the closed vent system that are designated, as described in 40 CFR 60.482-10a(l)(2), as difficult to inspect are exempt from the inspection requirements of 40 CFR 60.482-10a(f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR 60.482-10a(k)(1) through (k)(3). [40 CFR 60.482-10a(k)] Federally Enforceable Through Title V Permit

179. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The owner or operator shall record the following information: 1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment; 2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment; 3) For each inspection during which a leak is detected, a record of the information specified in 40 CFR 60.486a(c); 4) For each inspection conducted in accordance with 40 CFR 60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected; and 5) For each visual inspection conducted in accordance with 40 CFR 60.482-10a(f)(1)(ii) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected. [40 CFR 60.482-10a(l)] Federally Enforceable Through Title V Permit

180. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Closed vent systems and control devices used to comply with provisions Subpart GGGa shall be operated at all times when emissions may be vented to them. [40 CFR 60.482-10a(m)] Federally Enforceable Through Title V Permit

181. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in 40 CFR 60, Appendix A or other methods and procedures as specified in 40 CFR 60.485a, except as provided in 40 CFR 60.8(b). [40 CFR 60.485a(a)] Federally Enforceable Through Title V Permit

182. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The owner or operator shall determine compliance with the standards in 40 CFR 60.482-1a through 40 CFR 60.482-11a, 60.483a, and 60.484a as follows: Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used: (i) Zero air (less than 10 ppm of hydrocarbon in air); and (ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane. [40 CFR 60.485a(b)] Federally Enforceable Through Title V Permit

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183. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The owner or operator shall determine compliance with the no detectable emission standards in 40 CFR 60.482-2a(e), 60.482-3a(i), 60.482-4a, 60.482-7a(f), and 60.482-10a(e) as follows: 1) The requirements of 40 CFR 60.485a(b) shall apply. 2) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance. [40 CFR 60.485a(c)] Federally Enforceable Through Title V Permit

184. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The owner or operator shall test each piece of equipment unless demonstrated that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used: 1) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference as seen in 40 CFR 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment; 2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid; and 3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, the previous two procedures as specified in 40 CFR 60.485a(d)(1) and (2) shall be used to resolve the disagreement. [40 CFR 60.485a(d)] Federally Enforceable Through Title V Permit

185. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The owner or operator shall demonstrate that an equipment is in light liquid service by showing that all the following conditions apply: 1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20 øC (1.2 in. H2O at 68 degrees F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference as seen in 40 CFR 60.17) shall be used to determine the vapor pressures; 2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20 degrees Celsius is equal to or greater than 20 percent by weight; and 3) The fluid is a liquid at operating conditions. [40 CFR 60.485a(e)] Federally Enforceable Through Title V Permit

186. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Samples used in conjunction with 40 CFR 60.485a(d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare. [40 CFR 60.485a(f)] Federally Enforceable Through Title V Permit

187. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: An owner or operator of more than one affected facility subject to the provisions Subpart GGGa may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility. [40 CFR 60.486a(a)] Federally Enforceable Through Title V Permit

188. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: When each leak is detected as specified in 40 CFR 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply: 1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment; 2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in 40 CFR 60.482-7a(c) and no leak has been detected during those 2 months; and 3) The identification on equipment except on a valve, may be removed after it has been repaired. [40 CFR 60.486a(b)] Federally Enforceable Through Title V Permit

189. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: When each leak is detected as specified in 40 CFR 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 5 years in a readily accessible location: 1) The instrument and operator identification numbers and the equipment identification number; 2) The date the leak was detected and the dates of each attempt to repair the leak; 3) Repair methods applied in each attempt to repair the leak; 4) ``Above 10,000" if the maximum instrument reading measured by the methods specified in 40 CFR 60.485(a) after each repair attempt is equal to or greater than 10,000 ppm; 5) ``Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak; 6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown; 7) The expected date of successful repair of the leak if a leak is not repaired within 15 days; 8) Dates of process unit shutdown that occur while the equipment is unrepaired; and 9) The date of successful repair of the leak. [40 CFR 60.486a(c) and District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

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190. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The following information pertaining to the design requirements for closed vent systems and control devices described in 40 CFR 60.482-10a shall be recorded and kept in a readily accessible location: 1) Detailed schematics, design specifications, and piping and instrumentation diagrams; 2) The dates and descriptions of any changes in the design specifications; 3) A description of the parameter or parameters monitored, as required in 40 CFR 60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring; 4) Periods when the closed vent systems and control devices required in 40 CFR 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame; and 5) Dates of startups and shutdowns of the closed vent systems and control devices required in 40 CFR 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a. [40 CFR 60.486a(d)] Federally Enforceable Through Title V Permit

191. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The following information pertaining to all equipment subject to the requirements in 40 CFR 60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location: 1) A list of identification numbers for equipment subject to the requirements of Subpart GGGa; 2) (i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR 60.482-2a(e), 60.482-3a(i) and 60.482-7a(f). (ii) The designation of equipment as subject to the requirements of 40 CFR 60.482-2a(e), 60.482-3a(i) and 60.482-7a(f) shall be signed by the owner or operator; 3) A list of equipment identification numbers for pressure relief devices required to comply with 60.482-4a; 4) (i) The dates of each compliance test as required in 40 CFR 60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f). (ii) The background level measured during each compliance test. (iii) The maximum instrument reading measured at the equipment during each compliance test; and 5) A list of identification numbers for equipment in vacuum service. [40 CFR 60.486a(e)] Federally Enforceable Through Title V Permit

192. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The following information pertaining to all valves subject to the requirements of 40 CFR 60.482-7a(g) and (h) and to all pumps subject to the requirements of 40 CFR 60.482-2a(g) shall be recorded in a log that is kept in a readily accessible location: 1) A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump; and 2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve. [40 CFR 60.486a(f)] Federally Enforceable Through Title V Permit

193. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The following information shall be recorded for valves complying with 40 CFR 60.483-2a: 1) A schedule of monitoring; 2) The percent of valves found leaking during each monitoring period. [40 CFR 60.486a(g)] Federally Enforceable Through Title V Permit

194. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The following information shall be recorded in a log that is kept in a readily accessible location: 1) Design criterion required in 40 CFR 60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and 2) Any changes to this criterion and the reasons for the changes. [40 CFR 60.486a(h)] Federally Enforceable Through Title V Permit

195. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in 40 CFR 60.480a(d): 1) An analysis demonstrating the design capacity of the affected facility; 2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol; and 3) An analysis demonstrating that equipment is not in VOC service. [40 CFR 60.486a(i)] Federally Enforceable Through Title V Permit

196. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location. [40 CFR 60.486a(j)] Federally Enforceable Through Title V Permit

197. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The provisions of 40 CFR 60.7 (b) and (d) do not apply to affected facilities subject to Subpart GGGa. [40 CFR 60.486(k)] Federally Enforceable Through Title V Permit

FACILITY-WIDE REQUIREMENTS CONTINUE ON NEXT PAGE

198. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: All semiannual reports to the Administrator shall include the following information, summarized from the information in 40 CFR 60.486: 1) Process unit identification; 2) For each month during the semiannual reporting period, i) Number of valves for which leaks were detected as described in 40 CFR 60.482-7a(b) or 40 CFR 60.483-2a, (ii) Number of valves for which leaks were not repaired as required in 40 CFR 60.482-7a(d)(1), (iii) Number of pumps for which leaks were detected as described in 40 CFR 60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii), (iv) Number of pumps for which leaks were not repaired as required in 40 CFR 60.482-2a(c)(1) and (d)(6), (v) Number of compressors for which leaks were detected as described in 40 CFR 60.482-3a(f), (vi) Number of compressors for which leaks were not repaired as required in 40 CFR 60.482-3a(g)(1), (vii) number of connectors for which leaks were detected as described in 40 CFR 60.482-11a(b), (viii) number of connectors for which leaks were not repaired as required in 40 CFR 60.482-11a(d), (ix) the facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible; 3) Dates of process unit shutdowns which occurred within the semiannual reporting period; 4) Revisions to items reported in the semiannual report if changes have occurred since the initial report, as required in 40 CFR 60.487a (a) and (b), or subsequent revisions to the initial report. [40 CFR 60.487(c)] Federally Enforceable Through Title V Permit

199. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: An owner or operator electing to comply with the provisions of 40 CFR 60.483-1a and 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions. [40 CFR 60.487a(d)] Federally Enforceable Through Title V Permit

200. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: An owner or operator shall report the results of all performance tests in accordance with 40 CFR 60.8 of the General Provisions. The provisions of 40 CFR 60.8(d) do not apply to affected facilities subject to the provisions of Subpart GGGa except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests. [40 CFR 60.487a(e)] Federally Enforceable Through Title V Permit

201. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: The semiannual reporting requirements of 40 CFR 60.487a(a), (b), and (c) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of 40 CFR 60.487a(a), (b), and (c), provided that they comply with the requirements established by the State. [40 CFR 60.487a(f)] Federally Enforceable Through Title V Permit

202. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Compressors are exempt from the standards of Subpart GGGa if the owner or operator demonstrates that a compressor is in hydrogen service. Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E-260, E-168, or E-169 shall be used. An owner or operator may use engineering judgment to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures that conform to the general method described in ASTM E-260, E-168, or E-169 shall be used to resolve the disagreement. If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures that conform to the general method described in ASTM E-260, E-168, or E-169. [40 CFR 60.593a(b)] Federally Enforceable Through Title V Permit

203. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: An owner or operator may use the following provision in addition to 40 CFR 60.485a(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 øC as determined by ASTM Method D86-78, 82, 90, 95, or 96. [40 CFR 60.593a(d)] Federally Enforceable Through Title V Permit

204. 40 CFR PART 60 SUBPART VVa / GGGa CONDITION: Equipment that is in vacuum service is excluded from the requirements of 40 CFR 60.482-2a to 40 CFR 60.482-10a if it is identified as required in 40 CFR 60.486a(e)(5). [40 CFR 60.482-1a(d)] Federally Enforceable Through Title V Permit

FACILITY-WIDE REQUIREMENTS CONTINUE ON NEXT PAGE

205. Operator shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

206. Total stationary source (as defined in 40 CFR 63.2) emission shall not exceed 10 tons in any consecutive 12 month period of any hazardous air pollutant (HAP) (as defined in 40 CFR 63.2) and 25 tons in any consecutive 12 month period of any combination of HAPs. [District Rule 2201] Federally Enforceable Through Title V Permit

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

# AUTHORITY TO CONSTRUCT

DRAFT

**PERMIT NO:** S-37-4-22 **ISSUANCE DATE:** DRAFT

**LEGAL OWNER OR OPERATOR:** KERN ENERGY
**MAILING ADDRESS:** 7724 E PANAMA LN
BAKERSFIELD, CA 93307-9210

**LOCATION:** PANAMA LN & WEEDPATCH HWY
BAKERSFIELD, CA 93307-9210

**SECTION:** 25 **TOWNSHIP:** 30S **RANGE:** 28E

**EQUIPMENT DESCRIPTION:**
MODIFICATION OF PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSOR:INSTALL CHLORIDE SCRUBBER AND REVISE EMISSION FACTORS USING CORRELATION EQUATION

## CONDITIONS

1. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
2. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
3. Heaters shall be fired only on purchased commercial natural gas, refinery fuel gas, or any combination thereof. [District Rule 2201, 4001] Federally Enforceable Through Title V Permit
4. Sulfur content of fuel combusted in this unit shall not exceed 100 ppmv (as total reduced sulfur), based on a 3 hour rolling average. [District Rules 2201 and 40 CFR Part 60, Subpart J, 60.104(a)(1)] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

**YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT.** This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

DRAFT

Brian Clements, Director of Permit Services

S-37-4-22 : Feb 12 2025 7:29AM -- KLEVANND : Joint Inspection NOT Required



Southern Regional Office • 34946 Flyover Court • Bakersfield, CA 93308 • (661) 392-5500 • Fax (661) 392-5585

5. All refinery fuel gas combusted in the heaters shall be monitored for H2S content by a continuous emissions monitoring (CEM) system. CEM shall be installed, calibrated, operated, and reported according to EPA guidelines as specified under 40 CFR 60, Subpart J, Specification 7, and general requirements. CEM results shall be calculated on a rolling three (3) hour basis. [District Rules 2201, 4001, Subpart J, 60.105(a)(4) and 60.105(a)(4)iii] Federally Enforceable Through Title V Permit

6. Permittee shall obtain and analyze a representative gas sample for total reduced sulfur of the fuel combusted in this unit at least once per year. Each sample shall be analyzed for the following reduced sulfur compounds: carbon disulfide, carbonyl sulfide, dimethyl disulfide, dimethyl sulfide, hydrogen sulfide and methyl mercaptan. For each sample, permittee shall record the analytical results for total sulfur, calculated as the sum of the results for all analytes, expressed as H2S, and shall calculate and record the ratio of total sulfur to H2S. Samples shall be analysed using ASTM D6228-98, or an alternative analytical method approved in advance by the APCO. [District Rule 2201] Federally Enforceable Through Title V Permit

7. The permittee shall demonstrate continuous compliance with the sulfur content limit (as total reduced sulfur) of the fuel combusted in this unit by calculation, as the product of the fuel H2S concentration and the ratio of total sulfur to H2S, based on the most recently conducted fuel sample analysis for total sulfur. The total sulfur of the fuel shall be calculated for each one hour H2S monitoring result, and the hourly fuel sulfur values shall be averaged over a rolling three hour period to determine compliance. [District Rule 2201]

8. Emission rates from each heater, except during startup and shutdown, shall not exceed any of the following: NOx (as NO2): 25 ppmv @ 3% O2 or 0.030 lb/MMBtu, VOC: 5.5 lb/MMscf, PM10: 7.6 lb/MMscf or CO: 50 ppmv @ 3% O2. [District Rules 2201, 2520, 4301, 4305, 4306, and 4351] Federally Enforceable Through Title V Permit

9. {588} Particulate matter emissions shall not exceed 0.1 grain/dscf, 0.1 grain/dscf calculated to 12% CO2, nor 10 lb/hr. [District Rules 4201, 3.1 and 4301, 5.1 and 5.2.3] Federally Enforceable Through Title V Permit

10. Daily combustion emissions from this permit unit shall not exceed any of the following: NOx (as NO2): 42.6 lb/day, VOC: 7.8 lb/day, PM10: 10.8 lb/day, or CO: 52.5 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

11. The duration of each startup and shutdown period for each heater shall not exceed 12 hours and 9 hours respectively. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit

12. The permittee shall record the date and the duration of each startup and each shutdown. [District Rules 4305 and 4306]

13. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4351] Federally Enforceable Through Title V Permit

14. If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

15. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

16. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

17. Heater exhaust stacks shall be equipped with adequate provisions facilitating the collection of gas samples consistent with EPA Test Methods. [District Rule 1081] Federally Enforceable Through Title V Permit

18. Source testing to demonstrate compliance with NOx and CO emission limits shall be conducted not less than once every 12 months, except as provided below. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

19. Source testing to demonstrate compliance with NOx and CO emission limits shall be conducted not less than once every 36 months if compliance is demonstrated on two consecutive annual tests. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

20. If permittee fails any compliance demonstration for NOx or CO emission limits when testing not less than once every 36 months, compliance with NOx and CO emission limits shall be demonstrated not less than once every 12 months. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

21. Compliance demonstration (source testing) shall be by District witnessed, or authorized, sample collection by ARB certified testing laboratory. [District Rule 1081] Federally Enforceable Through Title V Permit

22. Compliance source testing shall be conducted under conditions representative of normal operation. [District Rule 1081] Federally Enforceable Through Title V Permit

23. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit

24. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

25. The following test methods shall be used unless otherwise approved by the APCO and EPA: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or ARB Method 100, and stack gas oxygen - EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

26. All required source testing shall conform to the compliance testing procedures described in District Rule 1081. [District Rule 1081] Federally Enforceable Through Title V Permit

27. {552} Copies of all fuel invoices, gas purchase contracts, supplier certifications, and test results used to determine compliance with the conditions of this permit shall be maintained. The operator shall record daily amount and type(s) of fuel(s) combusted and all dates on which unit is fired on any noncertified fuel. [District Rule 2520, 9.4.2 and 40 CFR 60.48c(g)] Federally Enforceable Through Title V Permit

28. {520} The operator shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.5.2] Federally Enforceable Through Title V Permit

29. {483} Nitrogen oxide (NOx) emission concentrations in ppmv shall be referenced at dry stack gas conditions, and shall be calculated to 3.00 percent by volume stack gas oxygen and averaged over 60 minutes, and lb/MMBtu rates shall be calculated as lb NO2/MMBtu of heat input (hhv). [District Rule 4305, 5.0, 8.2 and/or 4351, 8.1] Federally Enforceable Through Title V Permit

30. Draeger tubes shall be used as an alternative method for measuring fuel gas H2S during scheduled maintenance or unscheduled interruptions of CEMs. Draeger tube use shall be limited to no more than 96 continuous hours and fuel gas H2S shall be checked a minimum of every two hours during scheduled maintenance or unscheduled interruptions of CEMs. Alternate method of measuring fuel gas H2S shall occur no more than 192 hours in any calendar year. [40CFR60.13(i)] Federally Enforceable Through Title V Permit

31. Operator shall maintain all records of the reason for alternative monitoring and required fuel gas H2S monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

32. {4194} Pursuant to Rule 4320, beginning in 2010 the operator shall pay an annual emission fee to the District for NOx emissions from this unit for the previous calendar year. Payments are due by July 1 of each year. Payments shall continue annually until either the unit is permanently removed from service in the District or the operator demonstrates compliance with the applicable NOx emission limit listed in Rule 4320. [District Rule 4320]

33. {4253} Permittee shall maintain records of annual heat input (MMBtu) for this unit on a calendar year basis. Such records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and Rule 4320]

34. VOC emission rate from fugitive components associated with this emissions unit shall not exceed 9.7 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

35. Permit holder shall maintain accurate component count and resultant emissions according to California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, CAPCOA/CARB Table IV-3a: CAPCOA -Revised 1995 EPA Protocol Refinery Correlation Equations. Permit holder shall update such records when new components are approved and installed. [District Rule 2201] Federally Enforceable Through Title V Permit

36. Permit unit shall comply with applicable District Rule 4001 (NSPS, Subpart GGG) requirements on facility wide permit S-37-0. [District Rule 4001] Federally Enforceable Through Title V Permit

37. This unit is subject to Rule 4455 Leak Detection and Repair Conditions on the facility wide permit S-37-0. [District Rule 4455] Federally Enforceable Through Title V Permit

38. Permit unit shall comply with applicable District Rule 4001 (NSPS, Subpart GGG) requirements. [District Rule 4001] Federally Enforceable Through Title V Permit

39. Permittee shall comply with all applicable testing, recordkeeping, and reporting requirements specified in Rule 4001 - New Source Performance Standards, including but not limited to Subparts A and J. [District Rule 4001] Federally Enforceable Through Title V Permit

40. Operators shall not depressurize any vessel containing VOCs unless the process unit turnaround is accomplished by employing one of the following operating procedures: The organic vapors shall either be recovered, added to the refinery fuel gas system and combusted; or controlled and piped to an appropriate firebox or incinerated for combustion; or flared, until the pressure within the process vessel is as close to atmospheric pressure as is possible. All process vessels shall be depressurized into the control facilities to less than 1020 mm Hg (5 psig) before venting/opening to atmosphere. All organic compounds which emerge from a refinery process vessel during the purging of said vessel and which otherwise would be emitted to the atmosphere shall be either directed to a flare or incinerator or shall be used for fuel until such disposition of emissions is not technically feasible or is less safe than atmospheric venting. [District Rule 4454, 4.0] Federally Enforceable Through Title V Permit

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# APPENDIX B
## Current PTO

# San Joaquin Valley
# Air Pollution Control District

**PERMIT UNIT:** S-37-4-20 **EXPIRATION DATE:** 08/31/2027

**SECTION:** 25 **TOWNSHIP:** 30S **RANGE:** 28E

**EQUIPMENT DESCRIPTION:**
PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSORS

## PERMIT UNIT REQUIREMENTS

1. Heaters shall be fired only on purchased commercial natural gas, refinery fuel gas, or any combination thereof. [District Rule 2201, 4001] Federally Enforceable Through Title V Permit
2. Sulfur content of fuel combusted in this unit shall not exceed 100 ppmv (as total reduced sulfur), based on a 3 hour rolling average. [District Rules 2201 and 40 CFR Part 60, Subpart J, 60.104(a)(1)] Federally Enforceable Through Title V Permit
3. All refinery fuel gas combusted in the heaters shall be monitored for H2S content by a continuous emissions monitoring (CEM) system. CEM shall be installed, calibrated, operated, and reported according to EPA guidelines as specified under 40 CFR 60, Subpart J, Specification 7, and general requirements. CEM results shall be calculated on a rolling three (3) hour basis. [District Rules 2201, 4001, Subpart J, 60.105(a)(4) and 60.105(a)(4)iii] Federally Enforceable Through Title V Permit
4. Permittee shall obtain and analyze a representative gas sample for total reduced sulfur of the fuel combusted in this unit at least once per year. Each sample shall be analyzed for the following reduced sulfur compounds: carbon disulfide, carbonyl sulfide, dimethyl disulfide, dimethyl sulfide, hydrogen sulfide and methyl mercaptan. For each sample, permittee shall record the analytical results for total sulfur, calculated as the sum of the results for all analytes, expressed as H2S, and shall calculate and record the ratio of total sulfur to H2S. Samples shall be analysed using ASTM D6228-98, or an alternative analytical method approved in advance by the APCO. [District Rule 2201] Federally Enforceable Through Title V Permit
5. The permittee shall demonstrate continuous compliance with the sulfur content limit (as total reduced sulfur) of the fuel combusted in this unit by calculation, as the product of the fuel H2S concentration and the ratio of total sulfur to H2S, based on the most recently conducted fuel sample analysis for total sulfur. The total sulfur of the fuel shall be calculated for each one hour H2S monitoring result, and the hourly fuel sulfur values shall be averaged over a rolling three hour period to determine compliance. [District Rule 2201]
6. Emission rates from each heater, except during startup and shutdown, shall not exceed any of the following: NOx (as NO2): 25 ppmv @ 3% O2 or 0.030 lb/MMBtu, VOC: 5.5 lb/MMscf, PM10: 7.6 lb/MMscf or CO: 50 ppmv @ 3% O2. [District Rules 2201, 2520, 4301, 4305, 4306, and 4351] Federally Enforceable Through Title V Permit
7. Particulate matter emissions shall not exceed 0.1 grain/dscf, 0.1 grain/dscf calculated to 12% CO2, nor 10 lb/hr. [District Rules 4201, 3.1 and 4301, 5.1 and 5.2.3] Federally Enforceable Through Title V Permit
8. Daily combustion emissions from this permit unit shall not exceed any of the following: NOx (as NO2): 42.6 lb/day, VOC: 7.8 lb/day, PM10: 10.8 lb/day, or CO: 52.5 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

9. The duration of each startup and shutdown period for each heater shall not exceed 12 hours and 9 hours respectively. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit

10. For fugitive emissions components associated with Hydrogen Booster Compressor: Any leak greater than 500 ppmv for pump seals and compressor seals and 100 ppmv for valves and connectors, when measured with a portable hydrocarbon detection instrument calibrated with methane in accordance with EPA Method 21 or leaking at a rate of greater than 3 drops of liquid per minute, shall be repaired in a manner consistent with the procedures specified in Rule 4409 (adopted April 20, 2005). This requirement shall not apply to inaccessible or unsafe-to-access components as identified in the revised Operator Management Plan required by Rule 4455. [District Rules 2201 and 4455] Federally Enforceable Through Title V Permit

11. The permittee shall record the date and the duration of each startup and each shutdown. [District Rules 4305 and 4306]

12. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4351] Federally Enforceable Through Title V Permit

13. If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

14. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

15. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

16. Heater exhaust stacks shall be equipped with adequate provisions facilitating the collection of gas samples consistent with EPA Test Methods. [District Rule 1081] Federally Enforceable Through Title V Permit

17. Source testing to demonstrate compliance with NOx and CO emission limits shall be conducted not less than once every 12 months, except as provided below. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

18. Source testing to demonstrate compliance with NOx and CO emission limits shall be conducted not less than once every 36 months if compliance is demonstrated on two consecutive annual tests. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

19. If permittee fails any compliance demonstration for NOx or CO emission limits when testing not less than once every 36 months, compliance with NOx and CO emission limits shall be demonstrated not less than once every 12 months. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

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20. Compliance demonstration (source testing) shall be by District witnessed, or authorized, sample collection by ARB certified testing laboratory. [District Rule 1081] Federally Enforceable Through Title V Permit

21. Compliance source testing shall be conducted under conditions representative of normal operation. [District Rule 1081] Federally Enforceable Through Title V Permit

22. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit

23. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

24. The following test methods shall be used unless otherwise approved by the APCO and EPA: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or ARB Method 100, and stack gas oxygen - EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306 and 4351] Federally Enforceable Through Title V Permit

25. All required source testing shall conform to the compliance testing procedures described in District Rule 1081. [District Rule 1081] Federally Enforceable Through Title V Permit

26. Copies of all fuel invoices, gas purchase contracts, supplier certifications, and test results used to determine compliance with the conditions of this permit shall be maintained. The operator shall record daily amount and type(s) of fuel(s) combusted and all dates on which unit is fired on any noncertified fuel. [District Rule 2520, 9.4.2 and 40 CFR 60.48c(g)] Federally Enforceable Through Title V Permit

27. The operator shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.5.2] Federally Enforceable Through Title V Permit

28. Nitrogen oxide (NOx) emission concentrations in ppmv shall be referenced at dry stack gas conditions, and shall be calculated to 3.00 percent by volume stack gas oxygen and averaged over 60 minutes, and lb/MMBtu rates shall be calculated as lb NO2/MMBtu of heat input (hhv). [District Rule 4305, 5.0, 8.2 and/or 4351, 8.1] Federally Enforceable Through Title V Permit

29. Draeger tubes shall be used as an alternative method for measuring fuel gas H2S during scheduled maintenance or unscheduled interruptions of CEMs. Draeger tube use shall be limited to no more than 96 continuous hours and fuel gas H2S shall be checked a minimum of every two hours during scheduled maintenance or unscheduled interruptions of CEMs. Alternate method of measuring fuel gas H2S shall occur no more than 192 hours in any calendar year. [40CFR60.13(i)] Federally Enforceable Through Title V Permit

30. Operator shall maintain all records of the reason for alternative monitoring and required fuel gas H2S monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

31. Pursuant to Rule 4320, beginning in 2010 the operator shall pay an annual emission fee to the District for NOx emissions from this unit for the previous calendar year. Payments are due by July 1 of each year. Payments shall continue annually until either the unit is permanently removed from service in the District or the operator demonstrates compliance with the applicable NOx emission limit listed in Rule 4320. [District Rule 4320]

32. Permittee shall maintain records of annual heat input (MMBtu) for this unit on a calendar year basis. Such records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and Rule 4320]

33. VOC emission rate from fugitive components associated with this emissions unit shall not exceed 101.7 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

34. Permit holder shall maintain accurate component count and resultant emissions according to CAPCOA's "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities," Table IV-2a: 1995 EPA Protocol Refinery Screening Value Range Emission Factors. Permit holder shall update such records when new components are approved and installed. [District Rule 2201] Federally Enforceable Through Title V Permit

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35. Permit holder shall maintain accurate component count and resultant emissions from the Hydrogen Booster Compressor and #2 Hydrogen Compressors according to California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, CAPCOA/CARB Table IV-3a: CAPCOA -Revised 1995 EPA Protocol Refinery Correlation Equations. [District Rule 2201] Federally Enforceable Through Title V Permit

36. Except for complying with the applicable requirements of Sections 6.1 and 7.3, the requirements of this rule shall not apply to 1) components subject to Rule 4623 (adopted 5/19/05), 2) pressure relief devices, pumps, and compressors equipped with a closed vent system as defined in Section 3.0, 3) components buried below ground, 4) components exclusively handling liquid streams which have less than 10 percent by weight (<10 wt%) evaporation at 150 C, 5) components exclusively handling liquid streams with a VOC content less than ten percent by weight (<10 wt%), 6) components exclusively handling gas/vapor streams with a VOC content of less than one percent by weight (<1wt%), 7) components incorporated in lines exclusively in vacuum service, 8) components exclusively handling commercial natural gas, and 9) one-half inch nominal or less stainless steel tube fittings which have been demonstrated to the Air Pollution Control Officer (APCO) to be leak-free based on initial inspection. [District Rule 4455, 4.1 & 4.2] Federally Enforceable Through Title V Permit

37. Except for components subject to Rule 4623 (Storage of Organic Liquids) or for components included in the inspection and maintenance (I&M) program implemented pursuant to Section 5.7 of Rule 4623, the operator shall not use any component that leaks in excess of the allowable leak standards of Rule 4455, or is found to be in violation of the provisions specified in Section 5.1.3. A component identified as leaking in excess of an allowable leak standard may be used provided it has been identified with a tag for repair, has been repaired, or is awaiting re-inspection after repair, within the applicable time period specified within the rule. [District Rule 4455, 5.1.1] Federally Enforceable Through Title V Permit

38. Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere. [District Rule 4455, 5.1.2] Federally Enforceable Through Title V Permit

39. The operator shall be in violation of Rule 4455 if any District inspection demonstrates that one or more of the conditions in Section 5.1.4 (Leak Standards) exist at the facility. [District Rule 4455, 5.1.3.1] Federally Enforceable Through Title V Permit

40. Except for annual operator inspection described in Section 5.1.3.2.3, any operator inspection that demonstrates that one or more of the conditions in Section 5.1.4 exist at the facility shall not constitute a violation of Rule 4455 if the leaking components are repaired as soon as practicable but not later than the time frame specified in Rule 4455. Such components shall not be counted towards determination of compliance with the provisions of Section 5.1.4. [District Rule 4455, 5.1.3.2.1] Federally Enforceable Through Title V Permit

41. Leaking components detected during operator inspection pursuant Section 5.1.3.2.1 that are not repaired, replaced, or removed from operation as soon as practicable but not later than the time frame specified in Rule 4455 shall be counted toward determination of compliance with the provisions of Section 5.1.4. [District Rule 4455, 5.1.3.2.2] Federally Enforceable Through Title V Permit

42. Any operator inspection conducted annually for a component type (including operator annual inspections pursuant to Section 5.2.5, 5.2.6, 5.2.7, or 5.2.8) that demonstrates one or more of the conditions in Section 5.1.4 exist at the facility shall constitute a violation of Rule 4455 regardless of whether or not the leaking components are repaired, replaced, or removed from operation within the allowable repair time frame specified in Rule 4455. [District Rule 4455, 5.1.3.2.3] Federally Enforceable Through Title V Permit

43. A component shall be considered leaking if one or more of the conditions specified in Sections 5.1.4.1 through 5.1.4.4 of Rule 4455 exist at the facility. Readings shall be taken as methane using a portable hydrocarbon detection instrument and shall be made in accordance with the methods specified in Section 6.4.1 of Rule 4455. [District Rule 4455, 5.1.4] Federally Enforceable Through Title V Permit

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44. The operator shall audio-visually inspect for leaks all accessible operating pumps, compressors and Pressure Relief Devices (PRDs) in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. Any identified leak that cannot be immediately repaired shall be reinspected within 24 hours using a portable analyzer. If a leak is found, it shall be repaired as soon as practical but not later than the time frame specified in Table 3. [District Rule 4455, 5.2.1 & 5.2.2] Federally Enforceable Through Title V Permit

45. The operator shall inspect all components at least once every calendar quarter, except for inaccessible components, unsafe-to-monitor components and pipes. Inaccessible components, unsafe-to-monitor components and pipes shall be inspected in accordance with the requirements set forth in Sections 5.2.5, 5.2.6, and 5.2.7. New, replaced, or repaired fittings, flanges and threaded connections shall be inspected immediately after being placed into service. Components shall be inspected using EPA Method 21. [District Rule 4455, 5.2.3, 5.2.4, 5.2.5, 5.2.6 & 5.2.7] Federally Enforceable Through Title V Permit

46. The operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, provided the operator meets all the criteria specified in Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis. [District Rule 4455, 5.2.8] Federally Enforceable Through Title V Permit

47. An annual inspection frequency approved by the APCO shall revert to quarterly inspection frequency for a component type if either the operator inspection or District inspection demonstrates that a violation of the provisions of Sections 5.1, 5.2 and 5.3 of the rule exists for that component type, or the APCO issued a Notice of Violation for violating any of the provisions of Rule 4455 during the annual inspection period for that component type. When the inspection frequency changes from annual to quarterly inspections, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency, giving the reason(s) and date of change to quarterly inspection frequency. [District Rule 4455, 5.2.9 & 5.2.10] Federally Enforceable Through Title V Permit

48. The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. To insure that the process PRD is operating properly, and is leak-free, the operator shall re-inspect the process PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release using EPA Method 21. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections. [District Rule 4455, 5.2.11] Federally Enforceable Through Title V Permit

49. Except for process PRD, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using EPA Method 21. [District Rule 4455, 5.2.12] Federally Enforceable Through Title V Permit

50. A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator. Any attempt by an operator to count such District inspections as part of the mandatory operator's inspections is considered to be willful circumvention and is a violation of this rule. [District Rule 4455, 5.2.13] Federally Enforceable Through Title V Permit

51. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag that contains the information specified in Section 5.3.3. The tag shall remain affixed to the component until the leaking component has been repaired or replaced; has been re-inspected using EPA Method 21; and is found to be in compliance with the requirements of Rule 4455. [District Rule 4455, 5.3.1 5.3.2 and 5.3.3] Federally Enforceable Through Title V Permit

52. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 4455, 5.3.4] Federally Enforceable Through Title V Permit

53. If the leak has been minimized but the leak still exceeds the applicable leak standards of Rule 4455, an operator shall repair or replace the leaking component, vent the leaking component to a closed vent system, or remove the leaking component from operation as soon as practicable but not later than the time period specified in Table 3. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Table 3, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required. [District Rule 4455, 5.3.5] Federally Enforceable Through Title V Permit

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54. If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall minimize the leak within one hour after detection of the leak. If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of Rule 4455, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 4455 5.3.6] Federally Enforceable Through Title V Permit

55. For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the requirements specified in Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6. [District Rule 4455, 5.3.7] Federally Enforceable Through Title V Permit

56. The operator shall monitor process PRD by using electronic process control instrumentation that allows for real time continuous parameter monitoring or by using telltale indicators for the process PRD where parameter monitoring is not feasible. [District Rule 4455, 5.4.1] Federally Enforceable Through Title V Permit

57. After a release from a process PRD in excess of 500 pounds of VOC in a continuous 24-hour period, the operator shall immediately conduct a failure analysis and implement corrective actions as soon as practicable but not later than 30 days to prevent the reoccurrence of similar release. For refineries processing greater than 20,000 barrels of crude oil per day, any subsequent release in excess of 500 pounds of VOC within a continuous 24-hour period shall be subject to the requirements of Section 5.4.5. [District Rule 4455, 5.4.3 & 5.4.4] Federally Enforceable Through Title V Permit

58. The operator of a refinery processing greater than 20,000 barrels of crude oil per day shall connect all process PRDs serving that process equipment to an APCO-approved closed vent system as defined in Section 3.0 if any of the conditions specified in Sections 5.4.5.1 and 5.4.5.2 occurs. Process PRDs subject to the provisions of Section 5.4.5 shall be connected to an APCO-approved closed-vent system as soon as practicable, but no later than the first turnaround after the requirement to connect becomes effective. [District Rule 4455, 5.4.5] Federally Enforceable Through Title V Permit

59. All major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator or District personnel to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but not later than 24 hours after discovery. The operator shall comply with the requirements of Sections 6.1.4 if there is any change in the description of major components or critical components. [District Rule 4455, 5.5.1 & 5.5.2] Federally Enforceable Through Title V Permit

60. The operator shall keep a copy of the operator management plan at the facility and make it available to the APCO, ARB and US EPA upon request. By January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any changes to the existing, approved operator management plan. [District Rule 4455, 6.1.2 & 6.1.4] Federally Enforceable Through Title V Permit

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61. The operator shall maintain an inspection log containing, at a minimum, 1) total number of components inspected, and total number and percentage of leaking components found by component types, 2) location, type, name or description of each leaking component, and description of any unit where the leaking component is found, 3) date of leak detection and method of leak detection, 4) for gaseous leaks, record the leak concentration in ppmv, and for liquid leaks record whether the leak is a major liquid leak or a minor liquid leak, 5) date of repair, replacement, or removal from operation of leaking components, 6) identification and location of essential component and critical components found leaking that cannot be repaired until the next process unit turnaround or not later one year after leak detection, whichever comes earlier, 7) methods used to minimize the leak from essential components and critical components that cannot be repaired until the next process unit turnaround or not later one year after leak detection, whichever comes earlier, 8) after the component is repaired or is replaced, the date of reinspection and the leak concentration in ppmv, 9) inspector's name, business mailing address, and business telephone number, and 10) the facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log. [District Rule 4455, 6.2.1] Federally Enforceable Through Title V Permit

62. Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, analyzer reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4455, 6.2.3] Federally Enforceable Through Title V Permit

63. The operator shall notify the APCO, by telephone or other methods approved by the APCO, of any process PRD release described in Sections 5.4.4 and 5.4.5, and any release in excess of the reportable quantity limits as stipulated in 40 CFR, Part 117, Part 302 and Part 355, including any release in excess of 100 pounds of VOC, within one hour of such occurrence or within one hour of the time said person knew or reasonably should have known of its occurrence. [District Rule 4455, 6.3.1] Federally Enforceable Through Title V Permit

64. The operator shall submit a written report to the APCO within thirty (30) calendar days following a PRD release subject to 6.3.1. The written report shall include 1) process PRD type, size, and location, 2) date, time and duration of the process PRD release, 3) types of VOC released and individual amounts, in pounds, including supporting calculations, 4) cause of the process PRD release, and 5) corrective actions taken to prevent a subsequent process PRD release. [District Rule 4455 6.3.2] Federally Enforceable Through Title V Permit

65. Copies of all records shall be retained for a minimum of five (5) years after the date of an entry. Such records shall be made available to the APCO, ARB, or US EPA upon request. [District Rule 4455, 6.2.2, 6.2.3 & 6.2.4] Federally Enforceable Through Title V Permit

66. Measurements of gaseous leak concentrations shall be conducted according to US EPA Method 21 using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with the procedures specified in US EPA Method 21 or the manufacturer's instruction, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. [District Rule 4455, 6.4.1] Federally Enforceable Through Title V Permit

67. The VOC content of exempt streams shall be determined using American Society of Testing and Materials (ASTM) D 1945 for gases and South Coast Air Quality Management District (SCAQMD) Method 304-91 for liquids. [District Rule 4455, 6.4.2] Federally Enforceable Through Title V Permit

68. For exempt streams, the percent by volume liquid evaporated at 150 deg C shall be determined using ASTM D 86. [District Rule 4455, 6.4.3] Federally Enforceable Through Title V Permit

69. Equivalent test methods other than specified in Sections 6.4.1 through 6.4.5 may be used provided such test methods have received prior approval from the US EPA, ARB, and APCO. [District Rule 4455, 6.4] Federally Enforceable Through Title V Permit

70. Permit unit shall comply with applicable District Rule 4001 (NSPS, Subpart GGG) requirements. [District Rule 4001] Federally Enforceable Through Title V Permit

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71. The owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in Subpart GGG. In doing so the owner or operator shall comply with the requirements of 40 CFR 60.484. [40 CFR 60.592(c)] Federally Enforceable Through Title V Permit

72. Affected facilities for which construction or modification commenced after January 4, 1983 shall comply with applicable requirements of 40CFR, Subpart GGG. [40CFR60.590(a)]]

73. Each Subpart GGG pump in light liquid service (PLLS) shall be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485(b), except as provided in 40 CFR 60.482-1(c) and 40 CFR 60.482-2(d), (e), and (f). Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal. A leak is detected if an instrument reading of 10,000 ppm or greater is measured or if there are indications of liquids dripping from the pump seal. [40 CFR 60.482-2(a) and (b)]

74. When a leak is detected for each PLLS, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR 60.482-9. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. [40 CFR 60.482-2(c)] Federally Enforceable Through Title V Permit

75. Any Subpart GGG PLLS equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of 40 CFR 60.482-2(a) provided the requirements specified in 40 CFR 60.482-2(d)(1) through (6) are met. [40 CFR 60.482(d)] Federally Enforceable Through Title V Permit

76. Any Subpart GGG PLLS that is designated, as described in 40 CFR 60.486(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR 60.482-2(a), (c), and (d) if the pump meets the requirements specified in 40 CFR 60.482-2(e)(1), (2), and (3). [40 CFR 60.482-2(e)] Federally Enforceable Through Title V Permit

77. If any Subpart GGG PLLS is equipped with a closed vent system capable of capturing and transporting leakage from the seal or seals to a control device that complies with the requirements of 40 CFR 60.482-10, it is exempt from the requirements of 40 CFR 60.482-2(a) through (e). [40 CFR 60.482-2(f)] Federally Enforceable Through Title V Permit

78. Any Subpart GGG pump in PLLS that is designated, as described in 40 CFR 60.486(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of 40 CFR 60.482-2(a) and 40 CFR 60.482-2(d)(4) through (6) if: 1). The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR 60.482-2(a); and 2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in 40 CFR 60.482-2(c) if a leak is detected. [40 CFR 60.482-2(g)] Federally Enforceable Through Title V Permit

79. Except during pressure releases, each Subpart GGG pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR 60.485(c). [40 CFR 60.482-4(a)] Federally Enforceable Through Title V Permit

80. After each pressure release, the Subpart GGG pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in 40 CFR 60.482-9. No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR 60.485(c). [40 CFR 60.482-4(b)] Federally Enforceable Through Title V Permit

81. Any Subpart GGG pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in 40 CFR 60.482-10 is exempted from the requirements of 40 CFR 60.482-4(a) and (b). [40 CFR 60.482-4(c)] Federally Enforceable Through Title V Permit

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82. Any pressure relief device that is equipped with a rupture disk upstream of the Subpart GGG pressure relief device is exempt from the 40 CFR 60.482-4(a) and (b), provided the owner or operator complies with the requirements in 40 CFR 60.482-4(d)(2) of this section. After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in 40 CFR 60.482-9. [40 CFR 60.482-4(d)] Federally Enforceable Through Title V Permit

83. Except for in-situ sampling systems and sampling systems without purges, each Subpart GGG sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in 40 CFR 60.482-1(c). Each closed-purge, closed-loop, or closed-vent system shall comply with the requirements specified in 40 CFR 60.482-5(b)(1), (2), (3), and (4). [40 CFR 60.482-5(a), (b), and (c)] Federally Enforceable Through Title V Permit

84. Each Subpart GGG open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR 60.482-1(c). The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with this condition at all other times. [40 CFR 60.482-6(a) and (c)] Federally Enforceable Through Title V Permit

85. Each Subpart GGG open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. [40 CFR 60.482-6(b)] Federally Enforceable Through Title V Permit

86. Subpart GGG open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of 40 CFR 60.482-6(a), (b) and (c). [40 CFR 60.482-6(d)] Federally Enforceable Through Title V Permit

87. Subpart GGG open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in 40 CFR 60.482-6(a) through (c) are exempt from the requirements of 40 CFR 60.482-6(a) through (c). [40 CFR 60.482-6(e)] Federally Enforceable Through Title V Permit

88. Each Subpart GGG valve in gas/vapor service and in light liquid service shall be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485(b) and shall comply with 40 CFR 60.482-7(b) through (e), except as provided in 40 CFR 60.482-7(f), (g), and (h), 40 CFR 60.483-1, 40 CFR 60.483-2, and 40 CFR 60.482-1(c). A leak is detected if an instrument reading of 10,000 ppm or greater is measured. [40 CFR 60.482-7(a) and (b)] Federally Enforceable Through Title V Permit

89. Any Subpart GGG valve in gas/vapor service or in light liquid service for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected. If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months. [40 CFR 60.482-7(c)] Federally Enforceable Through Title V Permit

90. When a leak is detected for any Subpart GGG valve in gas/vapor service or in light liquid service, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in 40 CFR 60.482-9. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the best practices specified in 40 CFR 60.482-7(e)(1), (2), (3), and (4), where practicable. [40 CFR 60.482-7(d) and (e)] Federally Enforceable Through Title V Permit

91. Any Subpart GGG valve in gas/vapor service or in light liquid service that is designated, as described in 40 CFR 60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR 60.482-7(a) if the valve meets the requirements specified in 40 CFR 60.482-7(f)(1), (2), and (3). [40 CFR 60.482-7(f)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

92. Any Subpart GGG valve in gas/vapor service or in light liquid service that is designated, as described in 40 CFR 60.486(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of 40 CFR 60.482-7(a) if: 1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR 60.482-7(a); and 2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times. [40 CFR 60.482-7(g)] Federally Enforceable Through Title V Permit

93. Any Subpart GGG valve in gas/vapor service or in light liquid service that is designated, as described in 40 CFR 60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of 40 CFR 60.482-7(a) if: 1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface; 2) The process unit within which the valve is located either becomes an affected facility through 40 CFR 60.14 or 40 CFR 60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult-to-monitor; and 3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year. [40 CFR 60.482-7(h)] Federally Enforceable Through Title V Permit

94. The owner or operator may elect to comply with the applicable provisions for Subpart GGG valves in gas/vapor service and in light liquid service as specified in 40 CFR 60.483-1 and 60.483-2. [40 CFR 60.592(b)] Federally Enforceable Through Title V Permit

95. If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and Subpart GGG valves in heavy liquid service, Subpart GGG pressure relief devices in light liquid or heavy liquid service, and Subpart GGG connectors, the owner or operator shall follow either one of the following procedures: 1) The owner or operator shall monitor the equipment within 5 days by the method specified in 40 CFR 60.485(b) and shall comply with the requirements of 40 CFR 60.482-8(b) through (d); or 2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak. A leak is detected if an instrument reading of 10,000 ppm or greater is measured. [40 CFR 60.482-8(a) and (b)] Federally Enforceable Through Title V Permit

96. When a leak is detected in Subpart GGG pumps and valves in heavy liquid service, Subpart GGG pressure relief devices in light liquid or heavy liquid service, and Subpart GGG connectors, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR 60.482-9. The first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the best practices described under 40 CFR 60.482-7(e). [40 CFR 60.482-8(c) and (d)] Federally Enforceable Through Title V Permit

97. Delay of Subpart GGG leak repair will be allowed if the repair is technologically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Delay of repair is allowed for equipment which is isolated from the process and which does not remain in VOC service. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown. [40 CFR 60.482-9(a)(b)(e)] Federally Enforceable Through Title V Permit

98. Delay of Subpart GGG leak repair for valves will be allowed if the owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair and when repair procedures are effected and when repair procedures ar effected, the purged material is collected and destroyed or recovered in a control device complying with 40 CFR 60.482-10. Delay of leak repair for pumps will be allowed if the repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and repair is completed as soon as practicable, but no later than 6 months after the leak was detected. [40 cfr 60.482-9(c)(d)] Federally Enforceable Through Title V Permit

99. For Subpart GGG closed vent systems and control devices, vapor recovery systems shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, whichever is less stringent. [40 CFR 60.482-10(b)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

100. For Subpart GGG closed vent systems and control devices, enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 degrees C. [40 CFR 60.482-10(c)] Federally Enforceable Through Title V Permit

101. Except as provided in 40 CFR 60.482-10(i) through (k), each Subpart GGG closed vent system used to comply with the provisions of Subpart GGG shall be inspected according to the procedures and schedule specified in 40 CFR 60.482-10(f)(1) and (f)(2). Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in 40 CFR 60.482-10(h). A first attempt at repair shall be made no later than 5 calendar days after the leak is detected. Repair shall be completed no later than 15 calendar days after the leak is detected. [40 CFR 60.482-10(f) and (g)] Federally Enforceable Through Title V Permit

102. Delay of repair of a Subpart GGG closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown. [40 CFR 60.482-10(h)] Federally Enforceable Through Title V Permit

103. If a Subpart GGG vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of 40 CFR 60.482-10(f)(1)(i) and (f)(2). [40 CFR 60.482-10(i)] Federally Enforceable Through Title V Permit

104. Any parts of the Subpart GGG closed vent system that are designated, as described in 40 CFR 60.482-10(l)(1), as unsafe to inspect are exempt from the inspection requirements of 40 CFR 60.482-10(f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR 60.482-10 (j)(1) and (j)(2). [40 CFR 60.482-10(j)] Federally Enforceable Through Title V Permit

105. Any parts of the Subpart GGG closed vent system that are designated, as described in 40 CFR 60.482-10(l)(2), as difficult to inspect are exempt from the inspection requirements of 40 CFR 60.482-10(f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR 60.482-10(k)(1) through (k)(3). [40 CFR 60.482-10(k)] Federally Enforceable Through Title V Permit

106. The owner or operator shall record the following information: 1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment; 2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment; 3) For each inspection during which a leak is detected, a record of the information specified in 40 CFR 60.486(c); 4) For each inspection conducted in accordance with 40 CFR 60.485(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected; and 5) For each visual inspection conducted in accordance with 40 CFR 60.482-10(f)(1)(ii) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected. [40 CFR 60.482-10(l)] Federally Enforceable Through Title V Permit

107. Closed vent systems and control devices used to comply with provisions Subpart GGG shall be operated at all times when emissions may be vented to them. [40 CFR 60.482-10(m)] Federally Enforceable Through Title V Permit

108. In conducting the Subpart GGG performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in 40 CFR 60, Appendix A or other methods and procedures as specified in 40 CFR 60.485, except as provided in 40 CFR 60.8(b). [40 CFR 60.485(a)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

109. The owner or operator shall determine compliance with the standards in 40 CFR 60.482, 60.483, and 60.484 as follows: Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used: (i) Zero air (less than 10 ppm of hydrocarbon in air); and (ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane. [40 CFR 60.485(b)] Federally Enforceable Through Title V Permit

110. The owner or operator shall determine compliance with the no detectable emission standards in 40 CFR 60.482-2(e), 60.482-3(i), 60.482-4, 60.482-7(f), and 60.482-10(e) as follows: 1) The requirements of 40 CFR 60.485(b) shall apply. 2) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance. [40 CFR 60.485(c)] Federally Enforceable Through Title V Permit

111. The owner or operator shall test each piece of Subpart GGG equipment unless demonstrated that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used: 1) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference as seen in 40 CFR 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment; 2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid; and 3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, the previous two procedures as specified in 40 CFR 60.485(d)(1) and (2) shall be used to resolve the disagreement. [40 CFR 60.485(d)] Federally Enforceable Through Title V Permit

112. The owner or operator shall demonstrate that the Subpart GGG equipment is in light liquid service by showing that all the following conditions apply: 1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20 øC (1.2 in. H2O at 68 degrees F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference as seen in 40 CFR 60.17) shall be used to determine the vapor pressures; 2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20 degrees Celsius is equal to or greater than 20 percent by weight; and 3) The fluid is a liquid at operating conditions. [40 CFR 60.485(e)] Federally Enforceable Through Title V Permit

113. Samples used in conjunction with 40 CFR 60.485(d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare. [40 CFR 60.485(f)] Federally Enforceable Through Title V Permit

114. An owner or operator of more than one affected facility subject to the provisions Subpart GGG may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility. [40 CFR 60.486(a)] Federally Enforceable Through Title V Permit

115. When each Subpart GGG leak is detected as specified in 40 CFR 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply: 1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment; 2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in 40 CFR 60.482-7(c) and no leak has been detected during those 2 months; and 3) The identification on equipment except on a valve, may be removed after it has been repaired. [40 CFR 60.486(b)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

116. When each Subpart GGG leak is detected as specified in 40 CFR 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following information shall be recorded in a log and shall be kept for 5 years in a readily accessible location: 1) The instrument and operator identification numbers and the equipment identification number; 2) The date the leak was detected and the dates of each attempt to repair the leak; 3) Repair methods applied in each attempt to repair the leak; 4) ``Above 10,000'' if the maximum instrument reading measured by the methods specified in 40 CFR 60.485(a) after each repair attempt is equal to or greater than 10,000 ppm; 5) ``Repair delayed'' and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak; 6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown; 7) The expected date of successful repair of the leak if a leak is not repaired within 15 days; 8) Dates of process unit shutdown that occur while the equipment is unrepaired; and 9) The date of successful repair of the leak. [40 CFR 60.486(c) and District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

117. The following information pertaining to the design requirements for Subpart GGG closed vent systems and control devices described in 40 CFR 60.482-10 shall be recorded and kept in a readily accessible location: 1) Detailed schematics, design specifications, and piping and instrumentation diagrams; 2) The dates and descriptions of any changes in the design specifications; 3) A description of the parameter or parameters monitored, as required in 40 CFR 60.482-10(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring; 4) Periods when the closed vent systems and control devices required in 40 CFR 60.482-2, 60.482-3, 60.482-4, and 60.482-5 are not operated as designed, including periods when a flare pilot light does not have a flame; and 5) Dates of startups and shutdowns of the closed vent systems and control devices required in 40 CFR 60.482-2, 60.482-3, 60.482-4, and 60.482-5. [40 CFR 60.486(d)] Federally Enforceable Through Title V Permit

118. The following information pertaining to all equipment subject to the requirements in 40 CFR 60.482-1 to 60.482-10 shall be recorded in a log that is kept in a readily accessible location: 1) A list of identification numbers for equipment subject to the requirements of Subpart GGG; 2) (i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR 60.482-2(e), 60.482-3(i) and 60.482-7(f). (ii) The designation of equipment as subject to the requirements of 40 CFR 60.482-2(e), 60.482-3(i) and 60.482-7(f) shall be signed by the owner or operator; 3) A list of equipment identification numbers for pressure relief devices required to comply with 60.482-4; 4) (i) The dates of each compliance test as required in 40 CFR 60.482-2(e), 60.482-3(i), 60.482-4, and 60.482-7(f). (ii) The background level measured during each compliance test. (iii) The maximum instrument reading measured at the equipment during each compliance test; and 5) A list of identification numbers for equipment in vacuum service. [40 CFR 60.486(e)] Federally Enforceable Through Title V Permit

119. The following information pertaining to all Subpart GGG valves subject to the requirements of 40 CFR 60.482-7(g) and (h) and to all Subpart GGG pumps subject to the requirements of 40 CFR 60.482-2(g) shall be recorded in a log that is kept in a readily accessible location: 1) A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump; and 2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve. [40 CFR 60.486(f)] Federally Enforceable Through Title V Permit

120. The following information shall be recorded for Subpart GGG valves complying with 40 CFR 60.483-2: 1) A schedule of monitoring; 2) The percent of valves found leaking during each monitoring period. [40 CFR 60.486(g)] Federally Enforceable Through Title V Permit

121. The following information shall be recorded in a log that is kept in a readily accessible location: 1) Design criterion required in 40 CFR 60.482-2(d)(5) and 60.482-3(e)(2) and explanation of the design criterion; and 2) Any changes to this criterion and the reasons for the changes. [40 CFR 60.486(h)] Federally Enforceable Through Title V Permit

122. The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in 40 CFR 60.480(d): 1) An analysis demonstrating the design capacity of the affected facility; 2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol; and 3) An analysis demonstrating that equipment is not in VOC service. [40 CFR 60.486(i)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

123. Information and data used to demonstrate that a piece of equipment is not in Subpart GGG VOC service shall be recorded in a log that is kept in a readily accessible location. [40 CFR 60.486(j)] Federally Enforceable Through Title V Permit

124. The provisions of 40 CFR 60.7 (b) and (d) do not apply to affected facilities subject to Subpart GGG. [40 CFR 60.486(k)] Federally Enforceable Through Title V Permit

125. All Subpart GGG semiannual reports to the Administrator shall include the following information, summarized from the information in 40 CFR 60.486: 1) Process unit identification; 2) For each month during the semiannual reporting period, i) Number of valves for which leaks were detected as described in 40 CFR 60.482-7(b) or 40 CFR 60.483-2, (ii) Number of valves for which leaks were not repaired as required in 40 CFR 60.482-7(d)(1), (iii) Number of pumps for which leaks were detected as described in 40 CFR 60.482-2(b) and (d)(6)(i), (iv) Number of pumps for which leaks were not repaired as required in 40 CFR 60.482-2(c)(1) and (d)(6)(ii), (v) Number of compressors for which leaks were detected as described in 40 CFR 60.482-3(f), (vi) Number of compressors for which leaks were not repaired as required in 40 CFR 60.482-3(g)(1), and (vii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible; 3) Dates of process unit shutdowns which occurred within the semiannual reporting period; 4) Revisions to items reported in the semiannual report if changes have occurred since the initial report, as required in 40 CFR 60.487 (a) and (b), or subsequent revisions to the initial report. [40 CFR 60.487(c)] Federally Enforceable Through Title V Permit

126. An owner or operator electing to comply with the provisions of 40 CFR 60.483-1 and 60.483-2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions. [40 CFR 60.487(d)] Federally Enforceable Through Title V Permit

127. An owner or operator shall report the results of all performance tests in accordance with 40 CFR 60.8 of the General Provisions. The provisions of 40 CFR 60.8(d) do not apply to affected facilities subject to the provisions of Subpart GGG except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests. [40 CFR 60.487(e)] Federally Enforceable Through Title V Permit

128. The Subpart GGG semiannual reporting requirements of 40 CFR 60.487(a), (b), and (c) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of 40 CFR 60.487(a), (b), and (c), provided that they comply with the requirements established by the State. [40 CFR 60.487(f)] Federally Enforceable Through Title V Permit

129. Compressors are exempt from the standards of Subpart GGG if the owner or operator demonstrates that a compressor is in hydrogen service. Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E-260, E-168, or E-169 shall be used. An owner or operator may use engineering judgment to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures that conform to the general method described in ASTM E-260, E-168, or E-169 shall be used to resolve the disagreement. If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures that conform to the general method described in ASTM E-260, E-168, or E-169. [40 CFR 60.593(b)] Federally Enforceable Through Title V Permit

130. For compliance with Subpart GGG, an owner or operator may use the following provision in addition to 40 CFR 60.485(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 øC as determined by ASTM Method D86-78, 82, 90, 95, or 96. [40 CFR 60.593(d)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

131. Equipment that is in vacuum service is excluded from the requirements of 40 CFR 60.482-2 to 40 CFR 60.482-10 if it is identified as required in 40 CFR 60.486(e)(5). [40 CFR 60.482-1(d)] Federally Enforceable Through Title V Permit

132. Permittee shall comply with all applicable testing, recordkeeping, and reporting requirements specified in Rule 4001 - New Source Performance Standards, including but not limited to Subparts A and J. [District Rule 4001] Federally Enforceable Through Title V Permit

133. Operators shall not depressurize any vessel containing VOCs unless the process unit turnaround is accomplished by employing one of the following operating procedures: The organic vapors shall either be recovered, added to the refinery fuel gas system and combusted; or controlled and piped to an appropriate firebox or incinerated for combustion; or flared, until the pressure within the process vessel is as close to atmospheric pressure as is possible. All process vessels shall be depressurized into the control facilities to less than 1020 mm Hg (5 psig) before venting/opening to atmosphere. All organic compounds which emerge from a refinery process vessel during the purging of said vessel and which otherwise would be emitted to the atmosphere shall be either directed to a flare or incinerator or shall be used for fuel until such disposition of emissions is not technically feasible or is less safe than atmospheric venting. [District Rule 4454, 4.0] Federally Enforceable Through Title V Permit

# APPENDIX C
## HRA Summary

# San Joaquin Valley Air Pollution Control District
# Risk Management Review

| | |
|---|---|
| To: | Dan Klevann – Permit Services |
| From: | Patrick C Chimienti – Technical Services |
| Date: | July 16, 2024 |
| Facility Name: | KERN ENERGY |
| Location: | PANAMA LN & WEEDPATCH HWY, BAKERSFIELD |
| Application #(s): | S-37-4-22 |
| Project #: | S-1233158 |

## 1. Summary

### 1.1 Risk Management Review (RMR)

| Units | Prioritization Score | Acute Hazard Index | Chronic Hazard Index | Maximum Individual Cancer Risk | T-BACT Required | Special Permit Requirements |
|---|---|---|---|---|---|---|
| 4 | 0.00 | 0.00 | 0.00 | 1.21E-09 | No | No |
| **Project Totals** | 0.00 | 0.00 | 0.00 | 1.21E-09 | | |
| **Facility Totals** | >1 | 9.55E-01 | 9.44E-02 | 1.82E-05 | | |

### 1.2 Proposed Permit Requirements

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Unit # 4 - 22

1. No special requirements.

## 2. Project Description

Technical Services received a request to perform a Risk Management Review (RMR) for the following:

- Unit -4-22: MODIFICATION OF PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSOR:INSTALL CHLORIDE SCRUBBER

## 3. RMR Report

### 3.1 Analysis

The District performed an analysis pursuant to the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015) to determine the possible cancer and non-cancer health impact to the nearest resident or worksite. This policy requires that an assessment be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold

Then, generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than 1.0. If a preliminary analysis demonstrates that either the units', the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required.

If a refined assessment is greater than one in a million but less than 20 in a million for carcinogenic impacts (cancer risk) and less than 1.0 for the acute and chronic hazard indices (non-carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For units that exceed a cancer risk of one in a million, Toxic Best Available Control Technology (TBACT) must be implemented.

Air toxics emissions for this project were calculated using the following methods:

- Volatile organic compound emissions from this proposed operation were provided by the Permit Engineer. These emissions were speciated into air toxics using emission factors derived from the 1991 source tests of central valley sites.

These emissions were input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy, risks from the proposed unit's toxic emissions were prioritized using the procedure in the 2016 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required.

The AERMOD model was used, with the parameters outlined below and meteorological data for 18-22 from Bakersfield (rural dispersion coefficient selected) to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

| Source Process Rates | | | | | |
|---|---|---|---|---|---|
| **Unit ID** | **Process ID** | **Process Material** | **Process Units** | **Hourly Process Rate** | **Annual Process Rate** |
| 4 | 22 | VOC | Lbs | 0.004 | 31 |

| Area Source Parameters | | | | | |
|---|---|---|---|---|---|
| **Unit ID** | **Unit Description** | **Release Height (m)** | **X-Length (m)** | **Y -Length (m)** | **Area ($m^2$)** |
| 4 | Chloride Scrubber | 1.83 | 27.49 | 64.58 | 1775.30 |

## 4. Conclusion

### 4.1 RMR

The cumulative acute and chronic indices for this facility, including this project, are below 1.0; and the cumulative cancer risk for this facility, including this project, is less than 20 in a million. In addition, the cancer risk for each unit in this project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit requirements listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

## 5. Attachments

A. Modeling request from the project engineer

B. Additional information from the applicant/project engineer

C. Prioritization score w/ toxic emissions summary

D. Facility Summary

# APPENDIX D
## Quarterly Net Emissions Change (QNEC)

**Quarterly Net Emissions Change (QNEC)**

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post-Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

VOC:
$PE2_{quarterly}$ = $PE2_{annual}$ ÷ 4 quarters/year
= 6,418 lb/year ÷ 4 qtr/year
= 1,605 lb PM10/qtr

$PE1_{quarterly}$ = $PE1_{annual}$ ÷ 4 quarters/year
= 6,366 lb/year ÷ 4 qtr/year
= 1,592 lb PM10/qtr

| Quarterly NEC [QNEC] | | | |
|---|---|---|---|
| **Pollutant** | **PE2 (lb/qtr)** | **PE1 (lb/qtr)** | **QNEC (lb/qtr)** |
| NOx | 3,887 | 3,887 | 0 |
| SOx | 2,364 | 2,364 | 0 |
| PM10 | 986 | 986 | 0 |
| CO | 4,791 | 4,791 | 0 |
| VOC | 1,605 | 1,592 | 13 |

# APPENDIX E
## Compliance Certification

# San Joaquin Valley Air Pollution Control District

## TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

### I. TYPE OF PERMIT ACTION (Check appropriate box)

☐ ADMINISTRATIVE AMENDMENT ☒ MINOR MODIFICATION ☐ SIGNIFICANT MODIFICATION

| COMPANY NAME: Kern Energy | FACILITY ID: S-37 |
|---|---|
| 1. Type of Organization: ☒ Corporation ☐ Sole Ownership ☐ Government ☐ Partnership ☐ Utility | |
| 2. Owner's Name: Kern Energy | |
| 3. Agent to the Owner: | |

### II. COMPLIANCE CERTIFICATION (Read each statement carefully and initial **applicable** circles for confirmation):

DM Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).

DM Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.

DM Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.

DM Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true, accurate, and complete.

DM For minor modifications, this application meets the criteria for use of minor permit modification procedures pursuant to District Rule 2520.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

DMcCoy

Signature of Responsible Official

06/16/2023

Date

David McCoy

Name of Responsible Official (please print)

Sr. Vice President - Operations

Title of Responsible Official (please print)

# APPENDIX F
## Emission Calculations

**Kern Energy**

**Project S-1233158, Permit Unit S-37-4 PE1**

## Fugitive Emissions Using Correlation Equation Emission Factors

California Implementation Guidelines for Estimating Mass Emissions
of Fugitive Hydrocarbon Leaks at Petroleum Facilities

*Table IV-3a: CAPCOA -Revised 1995 EPA Protocol Refinery Correlation Equations for Refineries and Marketing Terminals*

Fields shaded yellow are application specific values.

| Equipment Type | Service | Component Count | % Default Zeros | %Pegged (>10,000) | % in Correlation Range | Correlation Screening Value (ppm) | Default Zero Emissions (lb/day) | Pegged Emissions (lb/day) | Correlation Emissions (lb/day) | VOC emissions (lb/day) |
|---|---|---|---|---|---|---|---|---|---|---|
| Valves | All | 1,030 | 95.0% | 0.0% | 5.0% | 400 | 0.404 | 0.872 | 0.541 | 1.82 |
| Pump Seals | All | 12 | 95.0% | 0.0% | 5.0% | 500 | 0.011 | 0.014 | 0.076 | 0.10 |
| Others | All | 172 | 95.0% | 0.0% | 5.0% | 500 | 0.035 | 0.187 | 0.213 | 0.43 |
| Connectors | All | 4,672 | 95.0% | 0.0% | 5.0% | 400 | 1.761 | 1.854 | 1.548 | 5.16 |
| Flanges | All | 1,016 | 95.0% | 0.0% | 5.0% | 400 | 0.016 | 1.277 | 0.832 | 2.13 |
| Open-ended lines | All | 0 | 95.0% | 0.0% | 5.0% | 500 | 0.000 | 0.000 | 0.000 | 0.00 |

**Total VOC Emissions (lb/day) = 9.6**

**Total VOC Emissions (lb/yr) = 3,519**

Factors Used in Calculations - For Reference

| Equipment Type | Service | Default Zero Factor (kg/hr) | Pegged Factor (kg/hr) | Correlation Equation (kg/hr) |
|---|---|---|---|---|
| Valves | All | 7.800E-06 | 6.400E-02 | 2.27E-06(SV)^0.747 |
| Pump Seals | All | 1.900E-05 | 8.900E-02 | 5.07E-05(SV)^0.622 |
| Others | All | 4.000E-06 | 8.200E-02 | 8.69E-06(SV)^0.642 |
| Connectors | All | 7.500E-06 | 3.000E-02 | 1.53E-06(SV)^0.736 |
| Flanges | All | 3.100E-07 | 9.500E-02 | 4.53E-06(SV)^0.706 |
| Open-ended lines | All | 2.000E-06 | 3.300E-02 | 1.90E-06(SV)^0.724 |

**Kern Energy**

**Project S-1233158, Permit Unit S-37-4 PE2**

## Fugitive Emissions Using Correlation Equation Emission Factors

California Implementation Guidelines for Estimating Mass Emissions
of Fugitive Hydrocarbon Leaks at Petroleum Facilities

*Table IV-3a: CAPCOA -Revised 1995 EPA Protocol Refinery Correlation Equations for Refineries and Marketing Terminals*

Fields shaded yellow are application specific values.

| Equipment Type | Service | Component Count | % Default Zeros | %Pegged (>10,000) | % in Correlation Range | Correlation Screening Value (ppm) | Default Zero Emissions (lb/day) | Pegged Emissions (lb/day) | Correlation Emissions (lb/day) | VOC emissions (lb/day) |
|---|---|---|---|---|---|---|---|---|---|---|
| Valves | All | 1,075 | 95.0% | 0.0% | 5.0% | 400 | 0.421 | 0.910 | 0.564 | 1.90 |
| Pump Seals | All | 12 | 95.0% | 0.0% | 5.0% | 500 | 0.011 | 0.014 | 0.076 | 0.10 |
| Others | All | 179 | 95.0% | 0.0% | 5.0% | 500 | 0.036 | 0.194 | 0.221 | 0.45 |
| Connectors | All | 4,701 | 95.0% | 0.0% | 5.0% | 400 | 1.772 | 1.865 | 1.557 | 5.19 |
| Flanges | All | 1,023 | 95.0% | 0.0% | 5.0% | 400 | 0.016 | 1.286 | 0.838 | 2.14 |
| Open-ended lines | All | 0 | 95.0% | 0.0% | 5.0% | 500 | 0.000 | 0.000 | 0.000 | 0.00 |

**Total VOC Emissions (lb/day) = 9.8**

**Total VOC Emissions (lb/yr) = 3,571**

Factors Used in Calculations - For Reference

| Equipment Type | Service | Default Zero Factor (kg/hr) | Pegged Factor (kg/hr) | Correlation Equation (kg/hr) |
|---|---|---|---|---|
| Valves | All | 7.800E-06 | 6.400E-02 | 2.27E-06(SV)^0.747 |
| Pump Seals | All | 1.900E-05 | 8.900E-02 | 5.07E-05(SV)^0.622 |
| Others | All | 4.000E-06 | 8.200E-02 | 8.69E-06(SV)^0.642 |
| Connectors | All | 7.500E-06 | 3.000E-02 | 1.53E-06(SV)^0.736 |
| Flanges | All | 3.100E-07 | 9.500E-02 | 4.53E-06(SV)^0.706 |
| Open-ended lines | All | 2.000E-06 | 3.300E-02 | 1.90E-06(SV)^0.724 |

# Exhibit X. San Joaquin Valley Air Pollution Control District, BACT Guidance for Petroleum Refineries and Chemical Plants (accessed Sept. 28, 2026)

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.1.1*

Last Update: 4/7/2026

## Thermally Enhanced Oil Recovery - Steam Enhanced Crude Oil Production Wells

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Vapor control system with transfer of vapors to gas pipeline or re-injection to formation. Fugitive defect** and leak*** inspection via Audio-Visual-olfactory (AVO) or Optical gas imaging (OGI) inspections once each calendar week. Upon detection of emission or defect using AVO/OGI: First repair – immediately after the emission or defect is detected; Repair completion – pursuant to applicable repair requirements of District Rule 4401. All other leak detection and repair program meeting the requirements of Rule 4401. | | |
| SOx | | SOx scrubber with 95% sulfur removal or sulfur compounds reduced to no more than 1 gr S/100 dscf | Vapor control system with either transfer of vapors to gas pipeline or re-injection to formation |

** as defined in 40 CFR 60.5416c(a)(2)(iii)
*** as defined in Table 2 of South Coast AQMD Rule 1173 (11/01/24)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.1.7*

Last Update: 6/15/2020

## Petroleum Production - Sludge Dewatering, Various Locations

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Sludge tanks, vapor piping and processing equipment (except roll-off bins handling dewatered sludge) maintained leak free (as defined in Rule 4623) and vented to a vapor collection and control system that is designed and operated to reduce the VOC in the vapor by 98 weight percent or to an VOC outlet concentration of less than 20 ppmv, dry basis as hexane at 3% O2.<br><br>VOC control device shall be carbon adsorption (at least two carbon canister in series), thermal or catalytic oxidizer, smokeless flare or IC engine with three-way catalyst. Auxiliary fuel used in any control device shall be either natural gas or LPG fuel. | | |
| SOx | Reduction in H2S in collected vapors by a minimum of 95% or to no greater than 2.0 lb SOx/day through the use of treated carbon canisters, caustic scrubber or an equivalent control device. | | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

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San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.1.8*

Last Update: 2/4/2021

## Petroleum Production - Mobile Degassing Operation for Storage Tanks and Pipelines

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Tanks, vapor piping and processing equipment maintained leak free (as defined in Rule 4623) and vented to a vapor collection and control system that is designed and operated to reduce the VOC in the vapor by 98 weight percent or to an VOC outlet concentration of less than 20 ppmv, dry basis as hexane at 3% O2.<br><br>VOC control device shall be carbon adsorption (at least two carbon canister in series), thermal or catalytic oxidizer, smokeless air assist flare or IC engine with three-way catalyst. Auxiliary fuel used in any control device shall be either natural gas or LPG. | | |
| SOx | Reduction in collected vapors by a minimum of 95% or to no greater than 2.0 lb-SOx/day through the use of treated carbon canisters, caustic scrubber or an equivalent control device. | | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

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San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.1.10*

Last Update: 7/19/2018

## Organic Liquid Loading Rack

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Bottom fill loading (submerged pipe fill loading) with dry break couplers, or equivalent, and VOC emissions from the vapor collection and control system less than or equal to 0.015 pounds per 1,000 gallons of organic liquid transferred | | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

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San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.1.14*

Last Update: 12/28/2021

## Crude Oil Loading Rack, TVP >= 1.5 psia

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Use of dry-break couplers or equivalent with an average disconnect loss of no greater than 8 ml liquid per disconnect,<br><br>Inspection and maintenance program pursuant to District Rule 4624; and<br><br>Emissions controlled to less than 0.08 pounds per 1,000 gallons (for Rule 4624 Class 1 operations), or 95% by weight of the VOC displaced during organic liquid transfers of organic liquid transferred (for Rule 4624 Class 2 operations), use one of the below control methods, or equivalent:<br><br>A vapor collection and control system, or<br><br>Route the transferred liquid to a fixed roof container that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids); or<br><br>Route the transferred liquid to a floating roof container that meets the control requirements specified in Rule 4623; or<br><br>Route the transferred liquid to a pressure vessel equipped with an APCO-approved vapor recovery system that meets the control requirements specified in Rule 4623 or<br><br>Closed VOC emission control system | | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.1.15*

Last Update: 9/15/2021

## Biodiesel/Glycerol Production Operation

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | 100% capture (feedstock drying tanks, reactor vessels, acid treatment tanks, neutralization tanks, fatty acid tanks, and surge tanks all fully enclosed and vented to control device) and 99.5% VOC control by weight | | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.2.2*

Last Update: 7/22/2020

## Petroleum Refining - Valves & Connectors

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Leak defined as a dripping rate of more than three (3) drops per minute of liquid containing VOC or as a reading of methane, in excess of 100 ppmv above background when measured per EPA Method 21, for all components, and an Inspection and Maintenance Program pursuant to District Rule 4455 | | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.2.3*

Last Update: 7/22/2020

## Petroleum Refining - Pump and Compressor Seals

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Leak defined as a dripping rate of more than three (3) drops per minute of liquid containing VOC or as a reading of methane, in excess of 500 ppmv above background when measured per EPA Method 21, for all components, and an Inspection and Maintenance Program pursuant to District Rule 4455 | | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.2.5*

Last Update: 12/30/2020

## Petroleum Refineries and Chemical Plants - Diesel Fuel Processing, Sulfur Recovery Plant

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| SOx | Sulfur recovery unit with tail gas treating unit to treat gas to =< 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator - except during startup and shutdown | Sulfur recovery unit with two tail gas treating units in parallel (one as standby) to treat gas to =< 10 ppmv H2S (based on a three-hour, moving average) and a standby incinerator - except during startup and shutdown | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.2.7*

Last Update: 8/24/2020

## Natural Gas Processing Plant - Valves, Connectors, Flanges, Pressure Relief Device, Compressor Seals, and Pump Seals

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Inspection and maintenance program pursuant to District Rule 4409, with the following leak repair thresholds:<br><br>Leak defined as a dripping rate of more than three (3) drops per minute of liquid containing VOC,<br><br>and<br><br>A reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 for valves, flanges, compressor seals and pressure relief devices,<br><br>and<br><br>A reading of methane in excess of 500 ppmv above background when measured per EPA Method 21 for pump seals. | | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.3.3*

Last Update: 9/1/2021

## Floating Roof Organic Liquid Storage or Processing Tank

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Internal Floating Roof Tank meeting requirements of District Rule 4623<br><br>or<br><br>External Domed Floating Roof Tank meeting requirements of District Rule 4623 | | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.4.1*

Last Update: 3/1/2024

## Hydrogen Production - Process Vents

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | VOC emissions from process vents not to exceed 0.5 lb/MMscf of hydrogen produced (Equivalent to 96% capture and control) | Use of a Thermal Oxidizer Achieving 99% overall capture and control | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a State Implementation Plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

# Exhibit Y. Bay Area Air Quality Management District Best Available Control Technology (BACT) Guideline Petroleum Refinery Fugitive Emissions–Pumps (Jan. 18, 2006)

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | ***Pumps*** | Revision: | ***4*** |
| | | Document #: | ***137.1*** |
| Class: | ***All*** | Date: | ***01/18/06*** |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T]<br>2. *500 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *Double Mechanical Seals w/ Barrier Fluid; Magnetically Coupled Pumps; Canned Pumps; Magnetic Fluid Sealing Technology; or Gas Seal System Vented to Thermal Oxidizer or Other BAAQMD Approved Control Device; all w/BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T]<br>2. *Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T]<br>2. *500 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *Double Mechanical Seals w/ Barrier Fluid; Magnetically Coupled Pumps; Canned Pumps; or Magnetic Fluid Sealing Technology; all w/ BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T]<br>2. *Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T] |

***References***

*a. BAAQMD*
*b. EPA NSPS: 40 CFR 60 Subpart GGG (Petroleum Refineries) and 40 CFR 60 Subpart VV (Chemical Plants)*
*T. TBACT*

# Exhibit Z. Bay Area Air Quality Management District Best Available Control Technology (BACT) Guideline Petroleum Refinery Fugitive Emissions–Compressors, (Jan. 18, 2006)

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | ***Compressors*** | Revision: | ***4*** |
| | | Document #: | ***48B.1*** |
| Class: | ***All*** | Date: | ***01/18/06*** |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T]<br>2. *500 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *Double Mechanical Seals w/ Barrier Fluid; or Gas Seal System Vented to a Thermal Oxidizer or Other BAAQMD Approved Control Device; all w/ BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T]<br>2. *Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T]<br>2. *500 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *Double Mechanical Seals w/ Barrier Fluid; or Gas Seal System Vented to BAAQMD Approved Control Device; all w/ BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T]<br>2. *Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T] |

### *References*

*a. BAAQMD*
*b. EPA NSPS: 40 CFR 60 Subpart GGG (Petroleum Refineries) and 40 CFR 60 Subpart VV (Chemical Plants)*
*T. TBACT*

# Exhibit AA. Environmental Protection Agency Emission Reduction Banking Manual

United States
Environmental Protection
Agency

Office of
Planning and Management
Washington, D.C. 20460

September 1980
First Edition

Emission Reduction Banking and Trading Publication No. BG200

EPA

# Emission Reduction Banking Manual



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# Emission Reduction Banking Manual

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# AN INTRODUCTION TO BANKING

An emission reduction banking system offers communities and industry an attractive means of reducing the burden of meeting air quality goals. By providing both new and existing firms with increased flexibility in meeting pollution control requirements, a banking system works to reduce both the direct and indirect (e.g., uncertainty and delay) costs of compliance with the Clean Air Act. A banking system enables firms to receive credit for reducing their emissions beyond required levels of control, therefore providing an incentive for additional investment in pollution abatement. A banking system also provides a mechanism for communities to encourage economic development without compromising efforts to improve air quality.

**A banking system enables firms to receive credit for reducing their emissions beyond required levels of control.**

A banking system is simply an extension of an air pollution control agency's ongoing regulatory efforts. Banking builds on this base by establishing accounting and administrative procedures related to the creation and certification of surplus emission reductions that can be "banked" or stored by firms and used for:

- Offsets--to allow firms to locate and expand in nonattainment areas without degrading air quality;
- Bubbles--to allow existing firms to reduce their costs of meeting current emission limitations; and
- Prevention of Significant Deterioration (PSD)--to allow new firms locating in attainment areas to satisfy new source requirements.

A number of communities (e.g., Louisville, Seattle, San Francisco) already have incorporated banking into their regulatory programs. Many more are now in the process of developing a set of banking rules designed to meet the specific needs of their communities.

This manual draws on the experience of these initial efforts to develop banking systems. It is designed to serve as a guide to state and local agencies and industry in developing banking programs for their localities.

## 1.1 The Purpose of the Banking Manual

Banking is a flexible program, containing a number of important design options. Before adopting a banking rule, a community will want to closely examine the implications of alternative designs in the context of its particular pollution and economic development characteristics.

**The U.S. Environmental Protection Agency has issued a start notice for a federal regulation concerning banking.**

This regulation will not require state and local governments to adopt a banking and trading program. Banking is strictly an optional program. Nor will the regulation impose a specific design on localities electing to adopt a banking program. Rather, it sets forth basic principles inherent in the Clean Air Act (e.g., the maintenance of Reasonable Further Progress, demonstration of attainment) that cannot be violated by the operations of a banking and trading program. The federal regulation will provide a benchmark against which state and local governments can evaluate the legality of the design of their proposed banking programs, while also providing industry some degree of assurance that their investments in pollution control will be protected.

This manual serves primarily as guidance to state and local agencies developing banking programs. It explains the basic administrative steps and design options that fall within the bounds and conditions that will be specified by the upcoming EPA banking regulation. The alternatives discussed in this manual, however, are not exhaustive and localities are encouraged to explore innovative banking designs as long as they comply with Clean Air Act requirements.

## 1.2 What is "Banking?"

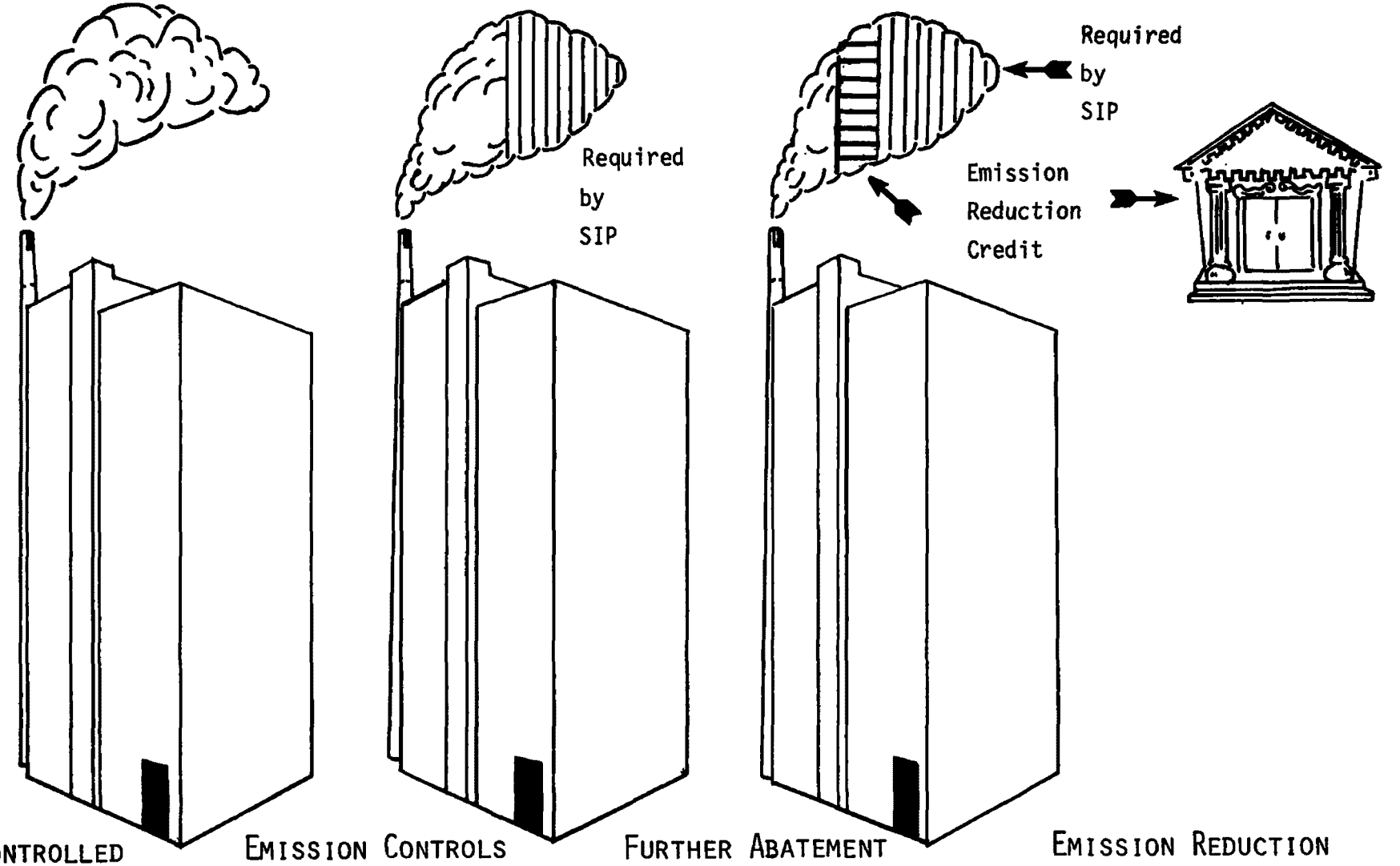
"Banking" is an important regulatory reform recently initiated by the EPA that seeks to encourage greater economic efficiency in meeting the requirements of the Clean Air Act.

A banking program establishes the administrative process by which a firm can receive credit for reducing its emissions beyond the baseline level required in the State Implementation Plan (SIP). The resulting "Emission Reduction Credit" forms the basis for a banking program. (See Exhibit 1.) Rules governing the creation, and use of Emission Reduction Credits constitute the banking system.

Emission Reduction Credits (ERCs) become an important asset to a firm for a number of reasons. A firm has the option of earning a profit on its investment in pollution control

EXHIBIT 1

# CREATING AN EMISSION REDUCTION CREDIT




UNCONTROLLED EMISSIONS

EMISSION CONTROLS REQUIRED BY SIP

FURTHER ABATEMENT CREATES AN EMISSION REDUCTION CREDIT

EMISSION REDUCTION CREDITS CAN BE BANKED FOR FUTURE USE OR SALE

by selling its ERCs to another firm, or it can use these credits itself--as offsets, in a bubble application, or to satisfy PSD requirements.

A banking system establishes the rules by which firms can create and use Emission Reduction Credits.

Banking and Emission Offsets

The emission offset program developed from the need to allow for industrial growth without adversely affecting air quality. Under the Clean Air Act, EPA established health-based ambient air quality standards and identified areas of the country which violated these standards. For those areas designated as "nonattainment," states were required to develop and enforce implementation plans calling for reductions in emissions necessary to achieve the desired level of air quality by 1982 for most pollutants, with a possible extension to 1987 for automobile-related emissions.

Efforts to reduce emissions from existing sources have generally progressed well. In most areas, the air is getting cleaner. But in many places, major metropolitan areas in particular, air quality still violates healthful levels.

Because of technological limitations, even with the most effective pollution abatement equipment new industrial development necessarily adds to the pollution problem in nonattainment areas. The original Clean Air Act adopted in 1970 offered a simple but not very practical solution to this problem--it prevented new industrial growth in all nonattainment areas. In 1976, EPA adopted an attractive alternative. Under the emission offset policy, new sources wanting to locate in nonattainment areas must install the most advanced control technology possible and must arrange for equivalent reductions in emissions from existing sources that more than "offset" its own emissions. This policy was incorporated into the 1977 amendments to the Clean Air Act and has been adopted by many states as a means of allowing new industrial growth in nonattainment areas without compromising efforts to attain cleaner air.1/

1/EPA issued an interpretative order on January 16, 1979 explaining the Section 173 offset provisions in the Clean Air Act. See Federal Register, Vol. 44, p. 3274. This federal policy was only in effect until states issued their own nonattainment strategies as part of their 1979 SIP revisions. Many states, however, incorporated the basic elements of EPA's interpretative order into their own rules.

Emission Reduction Credits provide a ready supply of emission offsets. They represent reductions in emissions from existing sources that have already been certified by the air pollution control agency and can be applied to offset emissions from new development in nonattainment areas. Their use as offsets should significantly aid a firm's search for acceptable offsets. In areas with a banking program, firms in need of offsets can simply examine the central ERC registry to determine the availability and source of offsets.

Banking and the Bubble

The "bubble" provides existing firms with increased flexibility in complying with current emission requirements.2/ It is a major variation of the conventional regulatory approach that sets specific emission restrictions at each emission point within a facility. Under this program reform, a firm can construct a "bubble" around emission points and arrange controls so that its overall limits are satisfied. Thus, the bubble allows plant managers the option of reducing emissions beyond existing requirements (i.e., create an Emission Reduction Credit) at emissions points where control costs are relatively low in lieu of reducing emissions from points where controls are expensive.

Firms are permitted to bubble within a facility or across facilities. Two different firms can even arrange to bubble between their facilities.

The bubble offers sources the opportunity to capture potentially significant savings. Firms are permitted to bubble within a facility or across facilities. Two different firms can even arrange to bubble between their facilities. All that is necessary is a demonstration that the surplus emission reduction is enforceable and compensates for the corresponding relaxation of controls.

To bubble, a firm must first reduce its emissions from one of its sources beyond the required amount. By doing so, the firm is in effect creating an Emission Reduction Credit. Banking provides for the systematic treatment of that surplus emission reduction. It reduces the uncertainty involved in applying to use the bubble, gives firms greater flexibility in deciding when to bubble, and provides a vehicle for bringing together firms that may want to bubble between their plants. By adopting a banking program, a community will be taking a significant step towards assisting local industry's use of the bubble to reduce its costs of pollution control.

2/EPA's Bubble Policy was published in the Federal Register on December 11, 1979 (Vol. 44, p. 71780).

Banking and Prevention of Significant Deterioration

In order to insure that air quality is not significantly degraded, new or expanding sources locating in attainment areas must satisfy the requirements of the prevention of significant deterioration (PSD) program.[3/] There are two potential uses for Emission Reduction Credits in the context of this program. ERCs created within a plant could be used by firms contemplating expansions or modifications in their existing facilities to reduce the net change in total emissions to a point below the threshold level triggering PSD new source review. In cases where PSD requirements are imposed, ERCs can also be used to satisfy offset requirements that result from violations of increment limitations.

Once an ERC has been created and banked, firms have maximum flexibility in deciding how best to use this asset--as an offset, in a bubble application, or to satisfy PSD requirements. See Exhibit 2. Regardless of the use it selects, a firm is better able to plan for future expansion and to minimize the costs of its compliance strategy by having these emission reductions on hand.

## 1.3 The Advantages of Banking

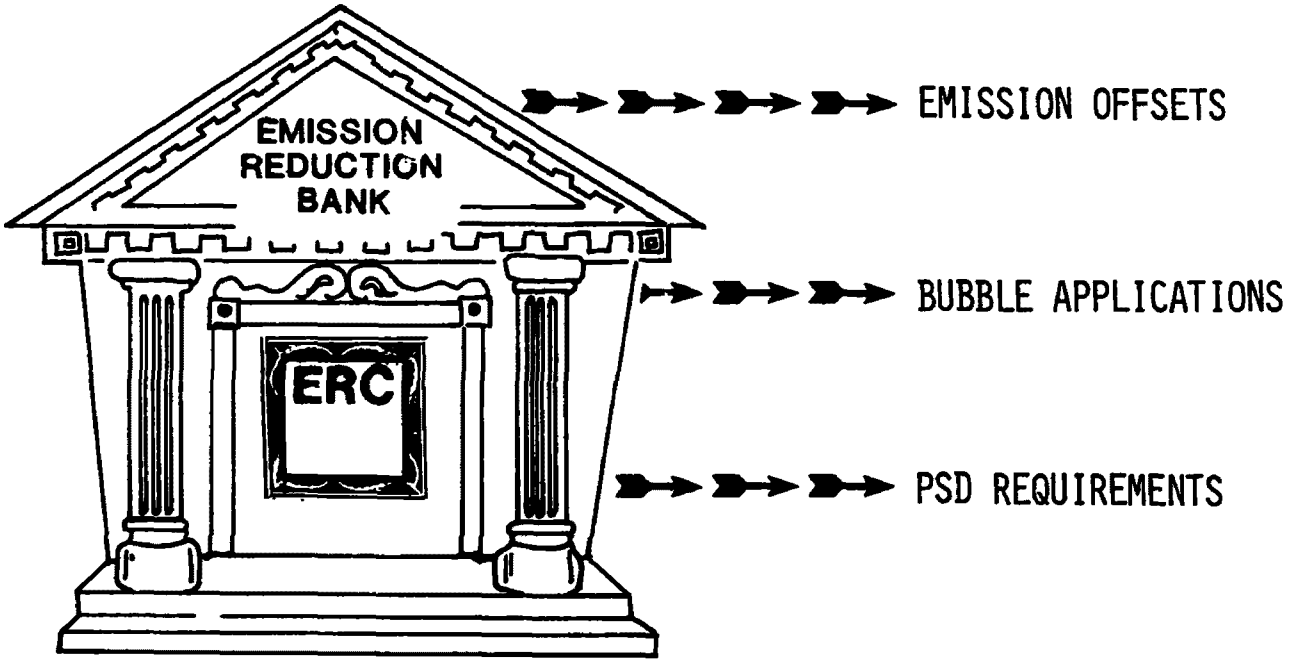
Firms have arranged for offsets and have applied to use a bubble in the absence of a banking system. How then can a banking program aid in the use of these programs? By providing for a systematic treatment of emission reductions, a formal banking program offers a number of distinct advantages for both air pollution control agencies and industry.

From an air pollution control agency's perspective, banking:

- increases the agency's flexibility in developing and implementing a plan to achieve and maintain air quality standards;
- establishes a set procedure for evaluating new source review and bubble applications--one that insures consistency with Clean Air Act requirements; and
- provides an incentive for firms to reduce their emissions beyond existing requirements.

EXHIBIT 2

### THE SEVERAL USES OF ERCs




From the standpoint of industry, a banking system is also attractive. Banking:

- provides an economic reward for a source that lowers its emissions below the required level;
- encourages technological innovation;

3/Specific rules concerning the use of emission reductions in the context of PSD requirements are explained in EPA's final regulations that are forthcoming in July. These regulations reflect changes in the program in order to comply with the Alabama Power v. Costle decision.

- reduces uncertainty and delay and therefore allows firms to plan ahead for future plant expansions, knowing that emission offsets are in hand; and

- facilitates the use of the bubble, therefore allowing existing firms to minimize the cost of complying with current and future emission standards.

Banking may also lower the overall costs of achieving a specified standard. When firms are required to reduce their emissions, they will have the option of evaluating different levels of investment in pollution abatement equipment. They may elect a control system more effective than required, if they can bank the resulting surplus emission reductions. Exhibit 3 illustrates how it is generally less expensive to install the most efficient controls possible, rather than adding additional controls in the future should that be necessary. Pollution abatement equipment typically cannot be designed and installed incrementally--to achieve additional reductions, production processes must be halted and existing control systems must often be scrapped. To avoid the unnecessary costs associated with two-stage retrofits, firms have the option of installing the most cost-effective equipment available and will receive credit for any surplus emission reductions that result.

Because of these advantages, the adoption of a banking program will:

- facilitate greater cooperation among air pollution control agencies and the sources they regulate;

- improve the efficiency of achieving and maintaining environmental quality; and

- remove some of the existing impediments to economic development.

Despite these advantages, in localities that adopt a banking program, a question arises as to whether firms will come forward to bank and receive credit for the emissions reductions they create, rather than simply holding onto them until the time they plan to sell or use them. In the absence of a detailed set of equitable rules, firms will not invest in controls to create Emission Reduction Credits. Without a clear set of rules that provide some measure of protection for Emission Reduction Credits stored in the bank--particularly a provision that safeguards banked ERCs in the case of further controls required to meet ambient air quality standards--it is unlikely that firms will declare and bank their emission reductions.4/

If some degree of protection for banked ERCs is clearly established in the locality's banking rules, a number of reasons exist for firms to participate in the banking program. By banking their surplus emission reductions, firms have a means to protect these emission reductions. In the future, if additional abatement is required to achieve ambient air quality standards, existing surplus emission reductions would likely be incorporated into the State's revised control strategy. Surplus emission reductions not banked and credited to a firm will not be protected and will likely be included as part of the revised demonstration of attainment. Moreover, under Section 172(b)(4) of the Clean Air Act, states are required to annually update their emission inventories to reflect "actual" emissions. Thus, states are required to incorporate into their air quality plans any voluntary reductions by firms.

**Emission Reduction Credits will be protected by the rules of the banking system.**

By banking and receiving credit for their surplus emission reductions, firms will legitimize their hold on these emission reductions. Perhaps, more importantly, the future use of these emission reductions will be facilitated because their validity and size will already have been confirmed by the air pollution control agency prior to the time when they are sold or applied to a permit application.

## 1.4 Who Should Develop a Banking Program?

The first question a state or locality should ask of itself is whether a banking program would significantly enhance its efforts to satisfy the requirements of the Clean Air Act. Different communities have different pollution problems and different economic development goals, and in some situations, banking may not contribute to their clean-up efforts.

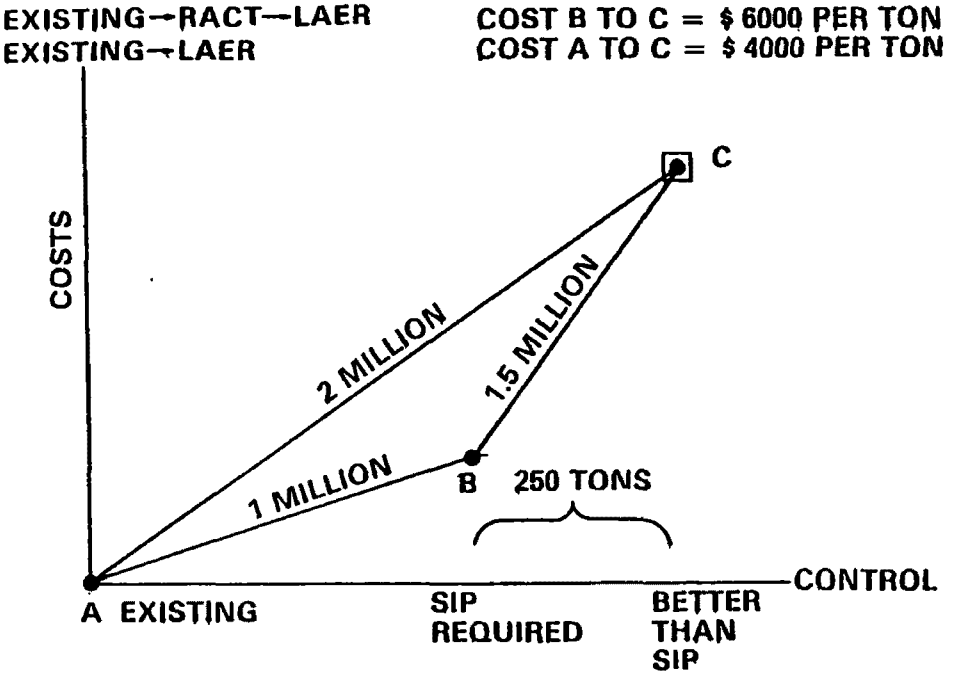
The impetus for a banking and trading program could arise from a number of sources. Firms considering a change in their production processes or their compliance strategies may inquire about the possibilities of banking surplus emission reductions which result from these actions. Economic development agencies interested in finding new ways to remove any environmental constraints in attracting industry to their communities are a second group likely to be interested in banking. New firms in search of offsets, or existing firms seeking to bubble in order to reduce their cost of meeting current requirements may also be the driving force behind the creation of a banking system.

Experience has shown that several candidate organizations could take the lead in designing and developing a banking program. (See Exhibit 4.) For example, in San Francisco, the local Air Quality Management District along with the regional business

4/See Section 2.4 of the manual for a discussion of design options for handling banked ERCs in the event of a SIP adjustment to re-establish Reasonable Further Progress.

EXHIBIT 3

# HOW BANKING CAN REDUCE THE DIRECT COSTS OF CONTROL




Banking gives firms the option of controlling emissions more than required to satisfy a standard based on reasonably available control technology (RACT).

(1) The difference between RACT and more stringent controls can be banked and becomes a valuable asset.

(2) If control requirements are further tightened, the banked emission reductions may be used to satisfy the new emissions limit at a substantial saving (here $.5 million) to the firm.

association was responsible for the adoption of a banking program.

In designing a banking system, both the characteristics of the existing air program and the economic development needs of the locality should be carefully considered. For example, in older industrial cities, where preserving jobs from existing industry will probably have a higher pay-off than seeking to attract new industry, a banking program should be designed both to help economic development officials attract new industry, and to facilitate the use of the bubble to aid existing firms to reduce their costs of control. The use of ERCs in the bubble should also serve to save jobs by prolonging the life of existing facilities without degrading air quality. To assure that the design of the banking system meets the needs of all affected parties, steps should be taken to incorporate their views and concerns during the design stage of developing the program.

Operating the banking program primarily involves regulating the creation and use of Emission Reduction Credits. These functions fall squarely within the purview of the air pollution control agency. Air pollution control agencies should not, generally, become involved in the actual trading of Emission Reduction Credits (e.g., setting prices, bringing together buyers and sellers). Trading activities--and using banking as a means of encouraging economic growth--should be undertaken by economic development agencies, metropolitan planning organizations, and industry associations.

**EXHIBIT 4**

## ORGANIZATIONS RESPONSIBLE FOR DEVELOPING BANKING PROGRAMS

| | |
|---|---|
| LOUISVILLE, KY | COUNTY AIR POLLUTION CONTROL BOARD |
| SAN FRANCISCO, CA | LOCAL AIR AGENCY/REGIONAL BUSINESS ASSOCIATION |
| SEATTLE, WA | REGIONAL AIR POLLUTION CONTROL AGENCY |

**Several indicators a community should examine to determine whether banking would be a useful extension of its ongoing air pollution control programs include:**

- **the existence of a significant number of medium to large industrial firms with facilities of varying ages;**
- **a concern that industrial firms are closing down and leaving the area;**
- **a desire to assist new firms wanting to locate in the area;**
- **a concern that existing firms are selecting alternative locations to expand;**
- **some likelihood that ambient air quality standards may not be achieved by the legislated deadlines; and**
- **a desire to modernize the industrial base by encouraging more rapid replacement of existing facilities.**

A trading system can expand the benefits of banking.

## 1.5 How To Use This Manual

The organization of this manual distinguishes between the design of the banking system and the start-up and operation of the system.

Part 2 presents an overview of the design of a banking system and then discusses in detail its five basic components. It also presents many of the design options possible for each component.

Part 3 focuses on the process a state or SIP designated locality will employ in developing and administering a banking program. It explores possible avenues for financing the start-up of a system, and discusses the administrative resources required for operation.

The appendices include a glossary of key terms used in this manual and an annotated bibliography describing related publications available from EPA.

# PART 2: DESIGNING A BANKING SYSTEM

Before presenting the details of an emission reduction banking system, a brief overview may be helpful. The introductory section presents:

- a discussion of the nature of the commodity, "Emission Reduction Credits," that serves as the basis for the banking system; and
- a summary of the five components of the system.

## Defining Emission Reduction Credits

There is an important distinction between the "emission reductions" (the physical reduction of emissions by a source) and Emission Reduction Credits (the commodity that is to be banked). Because a source reduces its emissions by 100 tons, this does not necessarily mean that either it or another source that purchases these credits has the right to pollute an additional 100 tons. The use of Emission Reduction Credits is subject to the rules governing the particular permit context (e.g., offsets or bubble applications) to which it is applied. In order to avoid confusion between the physical pollution units and the intangible commodity which is banked and ultimately used, the former are termed "emission reductions" and the latter are termed "Emission Reduction Credits".

**Credit will only be issued for emission reductions that are:**

**REAL—only reductions in actual emissions;**
**PERMANENT—only reductions that will be maintained over time; and**
**ENFORCEABLE—only reductions that legally bind the source and can be administered by the regulatory agency.**

**Although APCAs have considerable flexibility in defining what is acceptable as an ERC, the basic principles of real, permanent and enforceable must not be violated.**

Credits will entitle sources to meet certain requirements in State Implementation Plans for either obtaining new source permits or for meeting emission limits at existing sources. The use of ERCs must meet sufficiency and equivalency tests. Credits do not automatically entitle sources to increase their pollution; nor are these credits absolute entitlements or property rights of interminable duration. Major SIP revisions necessary to meet ambient air quality standards may require the regulatory agency to make adjustments in the amount of credit which has been granted to sources that have created surplus emission reductions. Provisions in a banking system must take into account this possibility.

Any necessary adjustments in banked emission reductions must be equitable. It is essential that the value of a credit be made as certain as possible if the banking opportunity is to attract additional investment in pollution controls. For example, if there were a SIP revision necessitating some adjustment, a rule requiring similar percent reductions from the quantity of banked credits and from uncontrolled emissions that are part of the inventory would be equitable and would safeguard the value of the credits to a firm.

## The Components of a Banking Process

There are five components of a banking system. Exhibit 5 presents a simulated overview of the banking process. This process is summarized below in the context of its five distinct components:

### COMPONENT 1: QUALIFYING EMISSION REDUCTIONS

This requires the reduction of emissions by a source below the baseline amount of actual emissions implied in the approved SIP's demonstration of attainment. This can be done by installing controls, altering operating parameters or inputs, or cutting back or closing operations. Only those emission reductions that satisfy explicit qualifications will receive banking credit.

### COMPONENT 2: QUANTIFYING EMISSION REDUCTIONS

Some formal administrative mechanism is needed to verify and endorse the quantity of emission reductions created by the source. A source would apply to have its permit changed to reflect the lower emission reduction level which it had achieved, thereby legally binding itself to emit at the lower level.

### COMPONENT 3: CERTIFYING THE ERCs

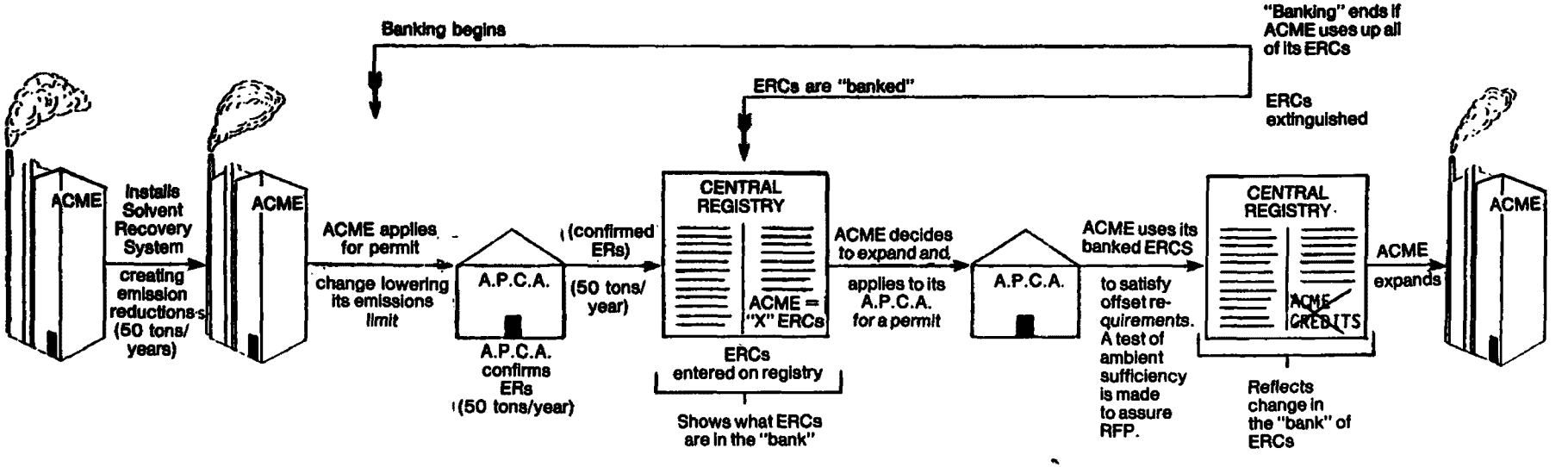
During this component, the emission reductions will be converted into Emission Reduction Credits (ERCs) and entered into the SIP. To be certified, an emission reduction must be real, permanent, and legally enforceable. ERCs represent the actual commodity being banked. The ERCs are certified and credited to the source by entry on a central registry.

### COMPONENT 4: BANKING AND ACCOUNTING FOR THE ERCs

This, in effect, is the means by which a source "stores" its ERCs for later use. While ERCs remain on the registry, appearing in the account of the creating source, the ERCs are "banked". If a SIP revision is necessary to demonstrate attainment with Clean Air Act standards, the quantity of ERCs may need to be adjusted.

EXHIBIT 6

# BANKING PROCESS OVERVIEW: AN EXAMPLE




An example may help. ACME has installed a solvent recovery system and has reduced its emissions (by 50 tons per year) below the baseline. ACME applies for a permit change (i.e., to require the reduced emissions) and thereby becomes involved in "banking." The real size of the emission reduction that will result from the controls proposed (not the changing of the permit) must be calculated. The confirmed ERs are converted into ERCs, are entered into the central registry, and the SIP is changed. ACME's ERCs are now "banked" and ACME is still involved in "banking." The ERCs (ACME's and those of others) that are credited on the central registry are the "bank" of ERCs. At some later date, ACME decides to expand its facilities and uses some or all of its ERCs to satisfy offset requirements necessitated by the expansion. The use of the ERCs to expand is reflected in the permit, and ACME's ERC account in the central registry will be debited for the amount of credits used to satisfy permit requirements. When this is done, ACME's ERCs which have been used cease to exist (and thus are no longer banked), and if ACME has used up all its ERCs, it no longer is engaged in banking. However, the bank of ERCs still exists (i.e., with all the remaining ERCs which sources have not used).

COMPONENT 5: USING BANKED EMISSION REDUCTION CREDITS

The source which has "banked" its ERCs can subsequently use these ERCs to satisfy emission limitations or new source review requirements. ERCs are converted into physical pollution allowances; the permit or its equivalent emission limitation in the SIP is changed to reflect the amount of ERCs being used by the source; and the ERCs used are extinguished and debited to the source's account in the central registry.

The following five sections present each of the essential components of a banking system in more detail. For each component there is first presented a discussion of its rationale, followed by an explanation of its key issues, and a summary.

## 2.1 Component 1: Qualifying the Emission Reduction

The initial component of a banking system requires the establishment of rules governing the qualification of emission reductions (ERs).

In establishing rules for the qualification of emission reductions, the principal objective is to encourage their production without jeopardizing the attainment and maintenance of ambient air quality and without creating an undue administrative burden. The key to the successful design of the first component of a banking system is to achieve the proper balance among these factors.

Rules governing the qualifications of emission reductions are necessary because not all sources and not all reductions in emissions will be acceptable for the purpose of banking. For an emission reduction to be banked the Air Pollution Control Agency (APCA) must be assured that it is real, permanent, and enforceable; was created in a manner acceptable under the banking rules; and was created from a source which is eligible to bank. In designing a banking rule, three issues relating to possible qualifications for banking should be addressed:

- What types of emission reductions can qualify for banking?
- What sources are eligible to bank emission reductions?
- What is the role of the APCA in qualifying emission reductions?

WHAT TYPES OF EMISSION REDUCTIONS CAN QUALIFY FOR BANKING?

Not all emission reductions can qualify for banking. Agencies should develop and publish rules or guidelines to discourage uninformed or frivolous proposals.

There are a number of reasons why certain types of emission reductions will not qualify for banking. The Clean Air Act (CAA) and its requirements set minimum qualifications for what emission reductions can be banked. The manner in which the SIP was designed also sets eligibility limits. It is essential that qualifications be clearly established in advance and available to all those potentially interested so that every party is treated fairly.

Clean Air Act Requirements. Implicit in the Clean Air Act are requirements that emission reductions must be real, permanent, and enforceable in order to qualify for banking. Failure to comply with these principles would result in a violation of reasonable further progress and the SIP's demonstration of attainment. In general:

- A "real" emission reduction means that actual air emissions are reduced.
- A "permanent" emission reduction means a reduction that is not temporary, intermittent, or short-lived (e.g., emission reductions from carpooling are frequently only temporary).
- An "enforceable" emission reduction is more than a "promise" of a reduction. It must be an action and a commitment that is legally binding and enforceable in the courts and by the regulatory agency.

These requirements set threshold qualifications for emission reductions. Other tests may have to be met as well in order to get credit for surplus emission reductions.

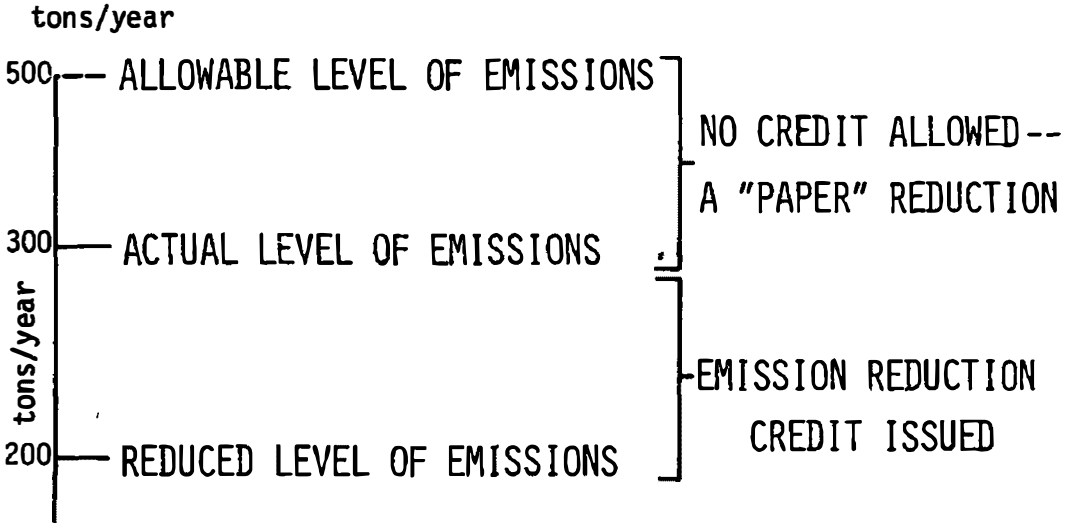
Actual vs. Paper Emission Reductions: SIP Design Affects Eligibility. In designing its SIP, a state has effectively set limits on the eligibility of certain classes of emissions. Eligibility limits include:

- emission reductions from sources not included in the SIP; and
- emission reductions already included in the SIP (explicitly or implicitly).

**For example, many sources have typically emitted pollution at levels below the "allowable" level specified in the SIP or in their permits. In almost every case, the ambient air value used for the SIP design and the demonstration of attainment were based on actual emissions. If these sources have their permits changed to allow only the lower level of existing actual emissions and can bank the difference between allowable and actual emissions, this would be a "paper" emission reduction—not a real one. This limitation is illustrated in Exhibit 6.**

**EXHIBIT 6**

# ONLY ACTUAL EMISSION REDUCTIONS WILL BE ELIGIBLE IN MOST CASES




Eligibility of "Paper" Reductions. In most cases, only actual reductions in emissions will be eligible for banking. "Paper"e reductions can not receive Emission Reduction Credits. "Paper" reductions are a change in permits (or other documentation) that does not reflect a reduction in actual emissions.

If Emission Reduction Credits were givene for "paper" reductions, actual ambient air quality would be worsened when the ERCs were finally used. This would clearly contradict the Reasonable Further Progress requirement.

**[illegible]ception**

**There is one situation where agencies may certify changes in allowables for banking credit. That is where a SIP used "potential ambient air" (e.g., the SIPs demonstration was modeled on the basis of allowable and not actual emissions) as a basis for its emission control strategy. Some state $SO_2$ and particulate plans may have this feature. This feature results in an implicit built-in margin for firms banking any reductions in their permits below the maximum allowable level and can still be consistent with meeting ambient air standards. If a source wishes to condition its permit, it could be credited for banking without endangering attainment.**

Most State Implementation Plans are designed on the basis of monitoring ambient air and therefore take into account actual levels of emissions and not those (higher) levels allowed by source permits. Thus, because the ambient air used in the SIP's demonstration of attainment had not incorporated allowable emissions, Emission Reduction Credits could not be issued to a source solely for the difference between its permitted emissions and its actual ones. To insure compliance with the Clean Air Act, in almost all cases, the baseline for calculating ERCs will be actual emissions. (See Exhibit 7.)

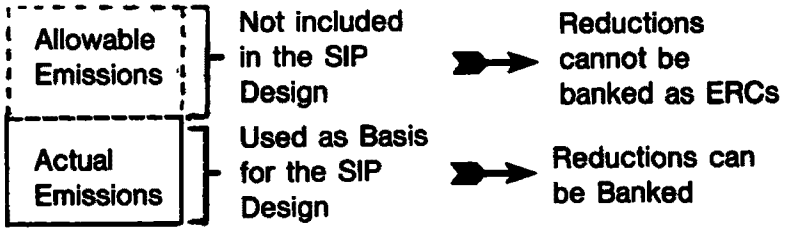
eeeFor example, a source has a permit allowing 500 tons of emissions per day but at the time the SIP was designede it regularly emitted only 400 tons.e This source would not be eligible toe have the 100 ton difference betweene its allowed emissions and its actual emissions to be certified as credits.e If this were done and the credits lateree used as an emissions allowance, the state would violate its SIP. Therefore, use of paper credits mustee be prohibited. A state that tries to adoptee a rule that allows paper credits willle be creating a basis for disapproval ofee its SIP.ee

**EXHIBIT 7**

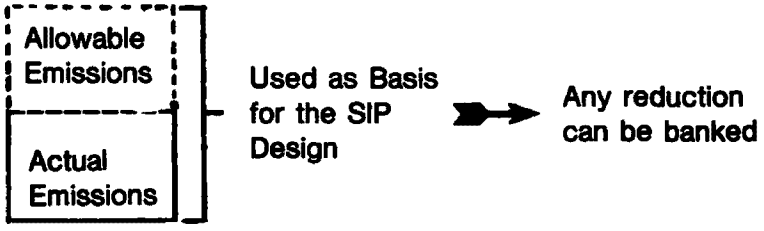
# ELIGIBILITY OF "PAPER" REDUCTIONS

Eligibility of pre-existing or paper reductions for banking as Emission Reduction Credits depends on whether the SIP was based on actual or allowable emissions.

In most states, SIPs are based on actual emissions (i.e., ambient air quality monitoring). Thus, paper reductions cannot be converted to ERCs and banked.




In a few instances, the ambient values used to design the SIP included the difference between actual emissions and allowables through modelling. Only if that difference were established by the agency and modeled can firms receive credit for reductions based on allowable emissions.



- If, alternatively, the ambient values used to develop a SIP were based on sources' allowable emissions (as specified in their permits), the situation would be different. Here, the difference between allowable and actual emissions could be certified as credits without violating the SIP.

In its rule, the APCA must determine for each pollutant which of the two cases is applicable and whether allowing the difference between actual and allowable emissions as ERCs would affect its ability to achieve and maintain ambient air quality standards. Without such a determination, a banking program would be in violation of provisions of the Clean Air Act.

Eligibility of emision reductions already in the SIP. Any emission reduction already included as part of the SIP's strategy for reaching attainment would not be eligible for banking. For example, some SIPs base their demonstration of attainment on (among other factors) certain assumptions about the replacement or a change in the mix of major industrial facilities. In this case, plant closings may have already been accounted for in the SIP and could not be credited again for banking.

Similarly, an emission reduction that occured prior to the development of the SIP, would in general already be incorporated or accounted for, and thus could not be certified for credit. This is because most SIPs are based on measurements of actual ambient air quality--these measurements already incorporate any existing emission reductions.

In many instances, emission reductions may have occurred after the design of the SIP, but before the inclusion of a SIP provision allowing banking. Such reductions may, at the option of the state, be eligible for credit after the banking rule has been enacted. That type of ER represents a real emissions reduction--in terms of how the SIP was designed--and would not interfere with Clean Air Act requirements, but may be excluded by the APCA for administrative or other reasons.

## WHAT SOURCES ARE ELIGIBLE TO BANK EMISSION REDUCTIONS?

Eligiblity to bank emission reductions may be limited by more than the requirements placed on types of emission reductions. State and local agencies may impose further optional limitations on the sources themselves, as distinguished from the emission reductions created by the source.

### Qualifying Minor and Nonconventional Sources

The possibility of qualifying minor sources for banking is an attractive option as a means of avoiding the placement of added control burdens on major stationery sources. Minor sources also represent a potentially inexpensive supply of ERCs.

Bringing minor sources into the banking system may reqüire considerable additional administrative resources, but may nonetheless be desirable in certain localities. Two basic steps are necessary:

(1) The baseline for the source must be established, and the source must provide some documentation that this baseline accurately represents its normal level of operation.

(2) A permit must be devised for the source so that the emission reduction achieved is enforceable.

Some legally enforceable and administratively acceptable mechanism must be employed to assure that reductions in a single minor source's emissions lead to a reduction in total emissions from such sources, as opposed to merely a shift in emissions from one minor source (that receives credit) to another. For example, if one dry cleaner reduced its emissions by shutting down, the likely result would be a shift in business and increased emissions from nearby dry cleaners.

After these two steps are satisfied, the usual administrative steps associated with the banking system can be taken.

The inclusion of nonconventional sources in the banking system presents a more difficult situation. A large quantity of certain pollutants (e.g., particulates, hydrocarbons) are the result of nonpoint sources, including roadways and construction sites. These pollutants are difficult to control, and from the standpoint of an agency confirming a reduction in emissions, they are difficult to measure. Traditional forms of measurement such as engineering analysis and stack tests are inapplicable. Without the ability to measure current emissions and the level of proposed abatement, any award of ERCs to the source would be arbitrary. Yet reductions from these sources do result in improved air quality, may be relatively cost effective to achieve (compared to additional controls on existing major sources), and may be essential to reaching ambient air quality standards.

Nonconventional sources would be very difficult to bring under the banking system. The following three conditions should be met as a condition of allowing nonconventional sources to qualify for banking.

(1) only permanent changes that can be verified are eligible--for example, the paving of a dirt road;

(2) the quantity of emission reductions confirmed must be determined by ambient air monitoring or by some other equally effective means; and

(3) the use of ERCs from these sources might be limited to conditions similar to those from which the ERC was created.

In areas where few major sources exist or where those that do exist are tightly controled, to achieve ambient air quality standards it may be necessary to bring minor and nonconventional sources into the banking system. Often local governments or quasi-governmental bodies can best capture nonconventional reductions. Because determination of who is entitled to claim a class of emission reductions is a question

of state discretion, it may be advantageous to give rights to these reductions to such bodies when the state develops its rule.

Optional Source Qualifications For Banking

An emission reduction may be eligible for banking if it is consistent with the requirements of the Clean Air Act and with the provisions and design of the SIP. However, state and local agencies are free to enact other eligibility qualifications. (See Exhibit 8.) These are optional and relate to both the type of emission reduction and who can receive credits.

Optional eligibility requirements can further define which emission reductions and source owners are qualified to participate in banking and which are not. Such optional qualifications can be based on a number of different factors. These include:

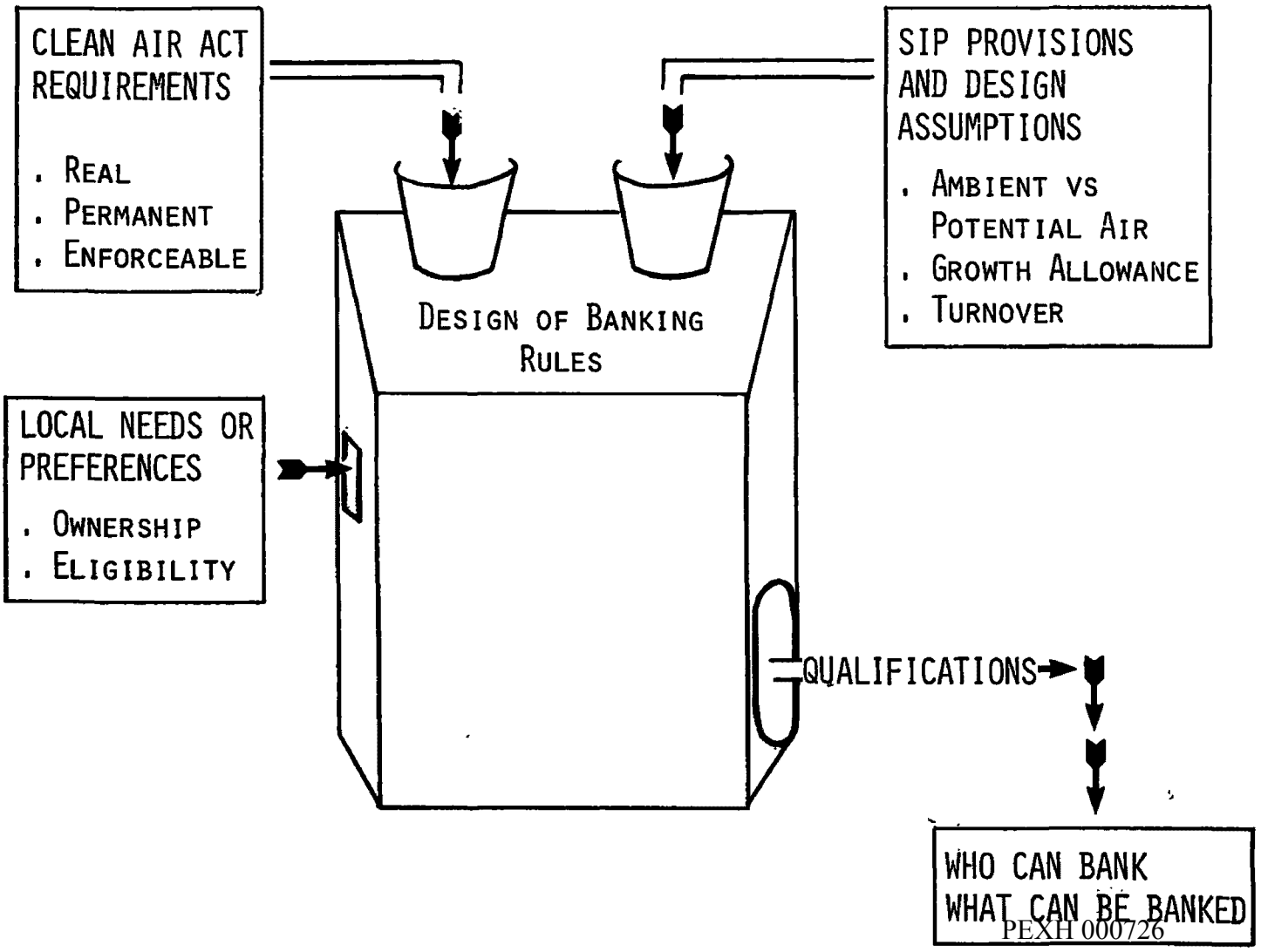
- method by which the reduction was created (e.g., closings);
- sources for which a baseline cannot be determined;
- compliance status of source;
- size of source or emission reduction;
- forthcoming controls or requirements under study; and
- ownership restrictions.

## Ownership Options

**There are a number of different options which states can use in fashioning ownership rules for banking programs. For example, certain classes of emission reductions (e.g., area sources) might be reserved for the state or local government. Reductions in emissions from major sources should generally be reserved for the major sources themselves. Without explicit ownership rights, such sources would get nothing from the production of emission reductions and therefore would not likely reduce their emissions beyond required levels.**

**EXHIBIT 8**

# DEVELOPMENT OF BANKING QUALIFICATIONS



Receiving credit for emission reduction banking is authorized by the state within limits set by (1) the Clean Air Act and its requirements (2) the SIP and its design, and (3) state and local law. This gives states substantial discretion to establish qualifications based on the above factors. However, such qualifications will need to be objective and rational.

Should Shutdowns be Allowed to Qualify as ERCs? The Pros and Cons

There has been much discussion concerning whether or not emission reductions which result from shutdowns should be allowed to qualify as ERCs. Here are some of the arguments on this issue:

Shutdowns Should not be Allowed as Sources of ERCs

1. Shutdowns often do not result in real reductions in emissions. Often, other facilities in the area will pick up the plant's customers if it is shutdown. The increased emissions of the other plants in the area would result in degrading air quality when ERCs from the shutdown are ultimately used.

2. Shutdowns may already be taken into account in the SIP. It is true that most shutdowns are not specifically provided for, but they may have already been considered in in the original demonstration of attainment used in the design of the SIP. If this were the case, to certify ERCs from shutdowns would result in double counting and a worsening of air quality.

Shutdowns Should be Allowed as Sources for ERCs

1. A shutdown is nothing more than a 100 percent reduction in output. If a 99 percent reduction can qualify as an ERC, then so should a 100 percent reduction. A shutdown is merely one end of a continuum from no reduction to total reduction, and every point along that continuum deserves similar treatment.

2. If shutdowns do not qualify for ERC status, then a "marginal" firm will have no incentive to close. Instead this firm will limp along until it can use the emission reductions itself. This will only impede efforts to improve air quality, as well as create economic inefficiency.

3. Shutdowns that are not used by a firm for replacement facilities could be qualified with a portion of the credits going to the state to satisfy Reasonable Further Progress or to be used to attract new investment to the community. The importance of jobs to a community may suggest that, when jobs are lost, ERCs from plant closings should be used to attract replacement companies.

4. Shutdowns may be a cost-effective way to control pollution that raises capital for firms to continue in business, invest, or meet other control requirements. Not giving credit for shutdowns may increase areawide closings.

It is important that the APCA explicitly establish the eligibility rules and that all sources are made aware that restrictions may be placed on having their emission reductions qualified as ERCs. Once the rules of the banking system are established, including a set of source eligibility criteria, it should be published for comment and, if possible, mailed directly to all potentially affected parties.

## Classes of ERCs

**One alternative to restricting eligibility entirely is to establish *different classes* of ERCs. Many economic development agencies are particularly interested in obtaining publicly controlled Emission Reduction Credits. Plant closings are one source sometimes discussed as a likely candidate for public control. It should be recognized that creating separate classes of ERCs complicates the system and may affect firms' incentives to reduce emissions. For example, a firm might be reluctant to shutdown a facility if it were not to receive credit for its reduction in emissions. The more complex the system the less likely it is to work.**

No source is prohibited from reducing emissions more than required; the eligibility restrictions are imposed when a source goes before the APCA to have the emission reductions converted into ERCs. This process will be discussed in detail in Part 2.2.

What is the Role of the APCA in Qualifying Emission Reductions?

The responsibility for actually creating an emission reduction falls entirely on a source. It is a voluntary decision. Emission reduction can be achieved by various means. Some of the more conventional means include installing control technology (e.g., scrubbers or precipitators), changing input practices (e.g., using natural gas in place of oil), or curtailing operations (e.g., shutting down a source). Individual sources are most likely to create ERs by:

- changes in abatement equipment;
- changes in industrial processes;
- shut-downs or cutbacks in operations that are no longer financially viable, and;
- shifts in fuels used for energy needs.

In each of these situations, a source would weigh the potential advantages gained by creating an emission reduction (for future use) against the costs associated with producing it. Sources need to be aware of eligibility restrictions on particular methods of creating emission reductions.

It is the APCA's responsibility to establish rules concerning the qualification of emission reductions. The role of the APCA does not end, however, after the promulgation and publication of these rules; the APCA can facilitate use of the banking system by making a nonbinding estimate of the credit that it expects to give a source if it meets

certain conditions. The conditions may include factors such as operation and design of process and equipment, and requirements for post-control monitoring. The APCA may also estimate the contingent reductions in ERCs which will occur if various conditions are violated. All of this should help the source to decide whether to proceed.

SUMMARY

The first component of the banking system involves the development of a clear set of rules governing participation in the banking program. The actual physical creation of the emission reduction by the source is but the culminating step in this component. Briefly, Component 1 of the banking system involves three basic activities:

(1) APCAs must promulgate eligibility and ownership rules (i.e., qualifications) for banking. These are based on three considerations:

- Clean Air Act requirements;
- SIP provisions and design assumptions; and
- local preferences and needs.

(2) Individual sources must determine whether or not they could qualify a proposed emission reduction--APCAs should be prepared to respond to inquiries.

(3) APCAs may make an estimate of probable ERCs which could be certified based on certain explicit assumptions and conditions.

The third point becomes the focus of the next component--The Quantification of Emission Reductions.

## 2.2 Component 2: Quantifying the Emission Reduction

After an emission reduction is created by a source, the reduction must be officially "quantified" by the APCA before it can be certified as a credit and banked.

The function of this component is threefold:

(1) To verify the quantity of the emission reduction created: The exact quantity may be in question because the techniques used to measure emission reductions are inexact.

(2) To verify the permanence of the emission reduction: Permanence of an emission reduction is absolutely essential; if a reduction is not permanent, it cannot be banked.

(3) To bind the source to the reduced level of emissions: Ideally, this will be achieved through the existing permit system. The permit provides an administrative record which clearly identifies the source, quantity, and characteristics of emission reductions. A firm must either be operating under a permit or be brought under a permit to participate in the banking system. The permit serves the dual functions of:

- establishing a baseline against which proposed reductions can be measured; and
- providing a legally enforceable instrument.

The change in a permit or creation of a new permit must also be incorporated into the SIP to be legally enforceable under the Clean Air Act.

As discussed in the previous section, only actual reductions in emissions will qualify, in most cases, for banking. If more credits are awarded than justified by the actual reduction, air quality will suffer when the ERCs are eventually used. The demonstration of attainment of Clean Air Act standards may also be jeopardized. Thus, accurate measurement must be part of a banking program.

To quantify an emission reduction, an APCA must:

(1) determine the initial baseline of actual emissions; and

(2) determine the proposed reduction in emissions.

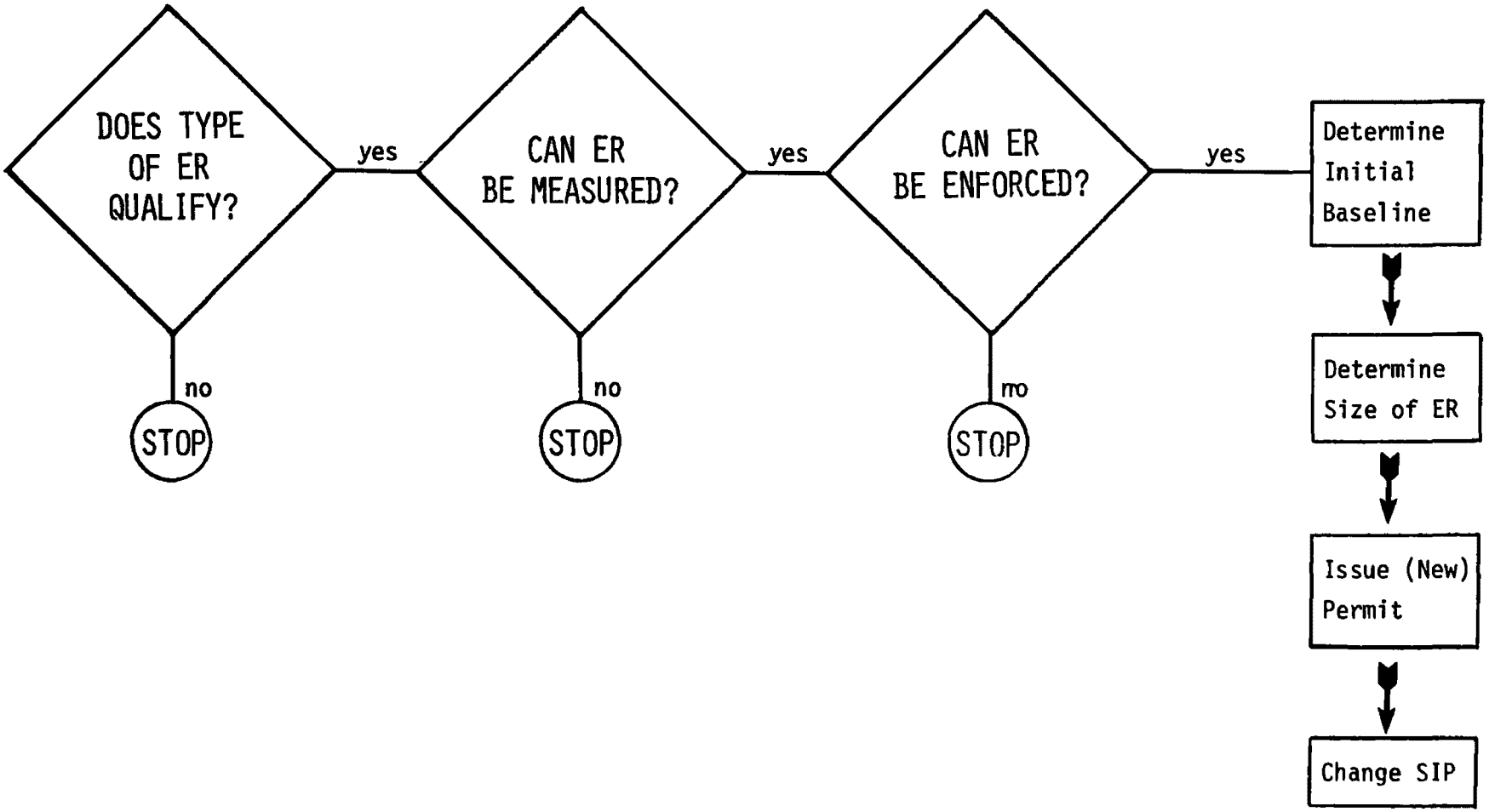
If an emission reduction cannot be measured and quantified, it cannot be certified and banked. Under a banking program, there must be strict accounting for ERCs. Thus, some way for an emission reductions to be quantified must be developed. This will be the most difficult aspect of banking. Where there is uncertainty, APCAs must insist that all claims be verified.

The process of quantifying emission reductions is described in Exhibit 9. The APCA is to determine the quantity and the acceptability of the emission reductions proposed by a source. In most states major sources have specific emission limitations written into their permits or into the SIP. However, these permit limitations will rarely be useable for calculating the emission reductions produced by a particular control. Where a permit specifies an emission limitation, it would be appropriate for use as the baseline only if the source has historically emitted at that level (i.e., if its actual emissions were equivalent to its allowables). This is infrequently the case.

- Permits themselves may not be sufficient documentation of actual past

EXHIBIT 9

# CONFIRMING AND QUANTIFYING EMISSION REDUCTIONS



levels of emissions. In many states, permits do not specify operating conditions, but only address technology requirements, or hourly rates. For this reason, permits specify only allowable limits and may not accurately describe actual emissions. As discussed earlier, only actual reductions can be certified in most cases.

Furthermore, in some situations a source may not be subject to a permit (e.g., a minor source or a source in a state without a permiting system), the terms of the permit may not specify a definite level of emissions that readily translates into an emission limitation (e.g., the permit specifies operating procedures, work practices, operation of equipment), or the permit may not reflect existing emissions at the time the SIP design value was calculated.

To determine the baseline in these situations, some form of engineering analysis, monitoring, or other form of audit is required. Because emission reductions must be real, permanent, and enforceable, the establishment of "before-and-after" baselines is an important function. Although the onus is clearly on the source to produce evidence documenting the creation of an emission reduction, the APCA must be able to "confirm" or verify this information. In situations where this is not possible, it may be necessary to deny a source's claim that it has created a certifiable emission reduction.

To determine actual annual operating hours, APCAs could ask sources to submit records, bills, and other documents which can substantiate the claim. Similarly, throughput on an annual basis can be estimated using engineering analyses. Establishment of a baseline will probably need to

## Four steps are involved in the process of quantifying an emission reduction.

(1) If the source is not operating under a permit, one must be issued. In some states, permits may not have been issued for all major sources, or the permits may not specify an exact emission standard for the source (e.g., it may specify a work practice, percent removal).

In these situations it is imperative for the APCA to establish a baseline of current emissions before determining the magnitude of emission reductions created by a source. For the source to engage in banking, it is essential that an operating permit be established based on the revised emission limits which result from creating and confirming an emission reduction.

(2) The APCA must establish the baseline and confirm the magnitude and permanence of the reduction claimed. This key step should not require the APCA to perform elaborate monitoring and measurement activities. The burden for documentation should be placed on the applying source. The APCA should clearly specify what type of information and documentation will be required. If additional supporting evidence is necessary, the APCA should require the source to obtain it; or, where desirable, the APCA could perform the tests itself, but impose the financial cost on the source. It is necessary, of course, that the APCA review the documentation received.

(3) The source's emission reduction permit must be legally enforceable. The APCA quantifies the source's emission reductions and rewrites the permit to reflect a lower (by the amount of confirmed emission reductions) emissions level (or a new control requirement that assures actual reductions) for the source. This has the effect of legally binding the source to emit at or below this new level. The permit change also should reflect any additional requirements that the source must meet to assure the permanency of the emission reduction--for example, periodic measurements, continuous monitoring, submission of input data--to verify that the new lower baseline is not being exceeded.

(4) The change must be made SIP enforceable. Under provisions of the Clean Air Act, all major sources must come under federally enforceable emission limits. This requirement is satisfied by the incorporation of source-specific emission limits or state operating permits as part of SIPs.

be done on a case-by-case basis in most instances. The burden of proof must be on the applicant to convincingly demonstrate and substantiate a baseline of actual emissions.

There are a variety of options which state agencies can use in developing baselines. For example, baseline levels could be defined as two-year averages of actual emissions. What is important is that agencies use consistent measurement or estimation techniques to determine baselines and emission reductions.

Estimates of the actual emission reduction achieved by particular kinds of control equipment are subject to wide margins of error. Because precision is not possible, alternative requirements must be used to assure that emission reductions are accurately measured. For example, parameter measures may be used to indirectly indicate the actual level of emissions.[5/] Similarly, some emission reduction techniques are monitored rather than the emission reductions they are presumed to create. Such techniques would include changes in work practices, processes, and inputs. The reductions achieved by these techniques may not be subject to accurate measurement, but the techniques themselves are subject to precise verification.

The change in a permit or creation of a new permit for banking must be incorporated into the SIP to be legally enforceable under the Clean Air Act.

Sources will want to consult with the APCA before deciding to create emission reductions with the anticipation of converting them into ERCs. As noted earlier, a source contemplating efforts to create ERCs will want to obtain from the APCA an estimate of how much credit its efforts will produce. The changes in the source's permit and the SIP revision formalize what the APCA has confirmed. These formalities must be satisfied before the emission reduction qualifies for banking credit. The certification process will be discussed in the next component.

SUMMARY

Component 2 requires that the creating source notify the APCA and provide adequate documentation that a specific emission reduction has been or will be made. To insure the enforceability of the reduction, changes are made in the source's permit and in the SIP. Only those emission reductions which are clearly identifiable measurable, and certain will be confirmed and, hence, available for conversion to ERCs. The steps, again, are:

(1) If the source is not operating under a permit, it must be brought under a permit reflecting the proposed emission reduction.

(2) The APCA must officially establish the baseline and confirm the magnitude and permanence of the reduction claimed.

(3) The source's permit must be changed to reflect reduced, actual emissions.

(4) The SIP must be changed to reflect the permit change.

## 2.3 Component 3: Certifying Emission Reduction Credits

An accounting system is necessary to maintain order in the creation and use of ERCs. Specifically, such a system should:

- impede fraudulent use of ERCs;
- reduce carelessness in banking ERCs;
- facilitate the APCA's oversight of banking activities; and
- provide legal protection to owners of ERCs.

ERC certification should coincide with emission reduction permitting and SIP revisions in order to achieve maximum efficiency and accuracy. Administratively, it should be relatively easy to establish one set of books (i.e., a registry) which would include the information necessary to account for the creation and use of ERCs.

The process of certification is illustrated by Exhibit 10. The formal certification (or issuance) of ERCs requires an APCA to determine that the source and emission reduction are fully qualified to receive a number of ERCs. Once credits are issued they vest certain privileges in the owner and may receive limited protection in the event of a SIP change (see Component 4).

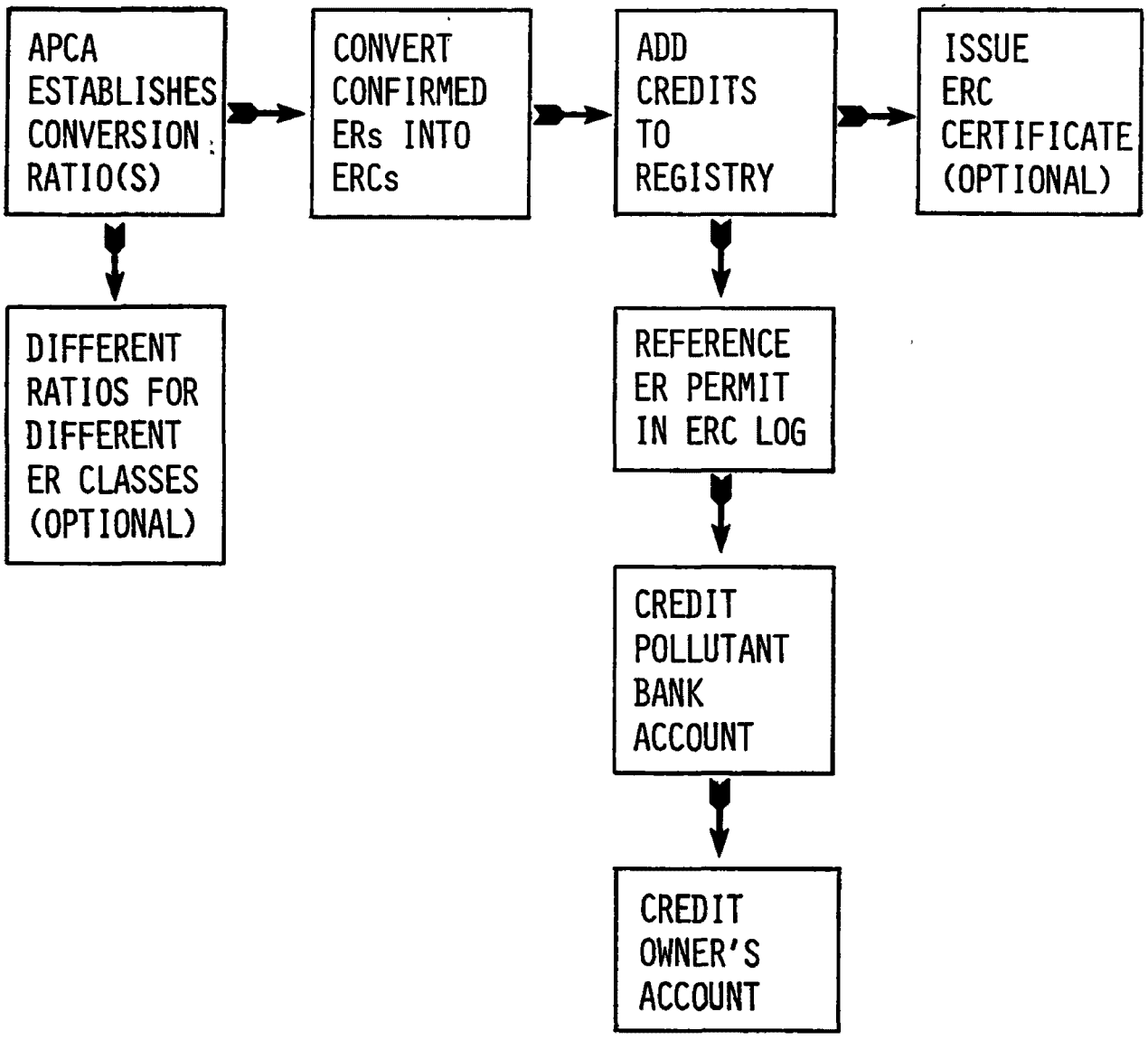
Sources are always free under the law to control their emissions more than required. However, no legal status attaches to those reductions. When the reductions are certified and converted into ERCs, sources are bound legally to emit a lower quantity of pollution. In exchange, sources receive an intangible though valuable asset--ERCs.

While valuable, an ERC is not a "right to pollute." It entitles the owner to certain

5/For example, the reduction can be measured indirectly by gauging the temperature, pressure, or other physical characteristics of the process affected by the control equipment.

EXHIBIT 10

# CERTIFYING EMISSION REDUCTION CREDITS



administrative privileges but does not circumvent the requirements for obtaining valid emission permits for using the public's air. To avoid misunderstanding, state agencies should make this distinction clear and explicit. For example, language in the certificate should state that the ownership of credits does not exempt a source from any permit requirements. Use of credits, however, can help a firm satisfy permit requirements.

One important rule needs to be emphasized: a grant of Emission Reduction Credits cannot be greater than the actual magnitude of the emissions reduced. However, reductions in actual emissions can be credited at less than one-for-one. If this is done, it must be on the basis of explicit rules that are applied in a consistent, rational manner. Thus different "conversion ratios" can be developed for various classes of emission reductions which reflect valid public policy concerns and measurement uncertainty. Alternatively, credits could be certified on a less than one-for-one basis for two other reasons: (1) to accumulate publicly-owned ERCs to be used in accordance with public purposes, or

## Options for Limiting the Life of ERCs

**States are not required to certify ERCs as valid in perpetuity. Instead, states may specify a definite period within which ERCs must be used, traded or forfeited. This could be done in order to discourage hoarding or monopolization of ERCs. However, such a restriction may create perverse incentives and may discourage production of emission reductions.**

(2) to help drive Reasonable Further Progress. In both of these instances, a less than one-for-one conversion ratio would be likely to severely discourage the production of voluntary emission reductions.

ERC Registry. A central registry must be established. Much like the way claims to land are registered, ERCs exist and belong to some entity when registered. This allows the tracking and accountability essential for banking (and trading) purposes. One set of books must be set up as the repository of information about the creation and use of ERCs. The APCA should maintain the registry. Use of an Emission Reduction Credits Register by an APCA will provide the most efficient mechanism of tracking and accounting for Emission Reduction Credits. The sample register presented in Exhibit 11 allows an APCA to track the certifying, banking, and use of ERCs. The sample register has three parts--a log for recording entries, a cumulative tally of banked ERCs by type of pollutant, and an "account" for each user of the banking program. Together, these three parts provide pertinent management and control information about the banking program.

- The ERC Log (Part 1). The log is essentially a sequential summary of information relating to the certifying and cancelling (i.e., the use) of ERCs. The log permits the tracking of Emission Reduction Credits by referencing the permit which incorporates the creation of the emission reduction. The log summary also contains such information as the identity of the owner of the credits, the location of the source, the amount of the credits, the pollutant involved, and the source class (if any). Detailed information concerning the characteristics of the emission reduction is essential in order to evaluate future effects on air quality at the time the ERC is used. Emission levels for reductions should be given in tons/hour, tons/month, and tons/year and emissions during the month of highest ambient concentration should also be specified.

  In addition to cross-referencing the permit which incorporates the confirmed emission reduction, the log also provides for the entry of subsequent information about the use of ERCs. Later entries documenting the use or adjustment of the ERC can be cross-referenced. This allows the APCA to reconstruct the entire chain of events surrounding the creation, banking and use of particular ERCs.

- The Cumulative Tally (Part 2). These tallies provide a cumulative overview of the amount of banked emissions for each pollutant. This account gets credited whenever an ERC is issued. Conversely, the account is debited whenever an ERC is used to provide an emissions allowance. The "Entry No." functions as a cross-reference back to the ERC Log and the information contained there.

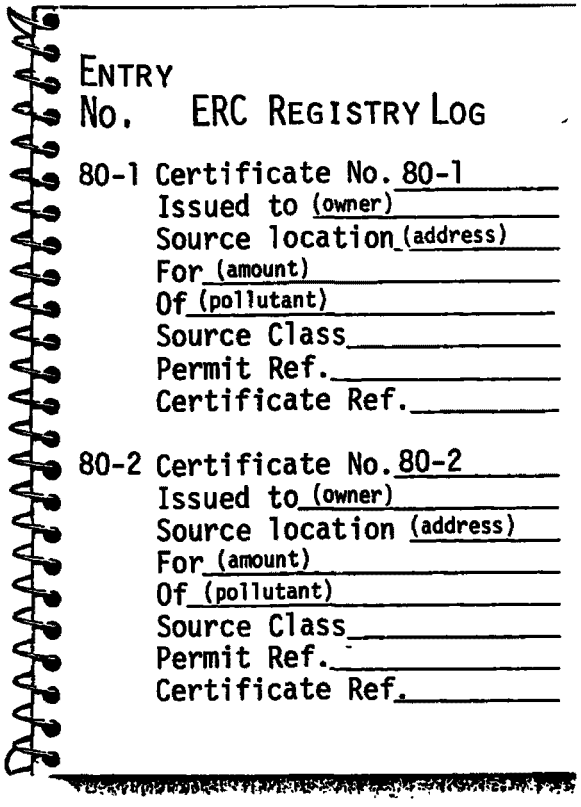
- The Individual Accounts (Part 3). When an ERC certificate is first issued to a source, an account is opened in the owner's name. Subsequent ERCs are credited to that individual owner's account. If ERCs are used in permits, the owner's account must be debited. This part of the Registry allows the APCA to determine quickly whether a source owner has enough credits in its account to cover a proposed use (or sale) of ERCs.

Each time an ERC is certified an initial entry in the registry should be made. The actual entry requirements should present a relatively minor administrative burden. In addition, the APCA should provide the source with some documentation. Three kinds of

EXHIBIT 11

# SAMPLE EMISSION REDUCTION CREDIT (ERC) REGISTER

## Part 1: ERC Log

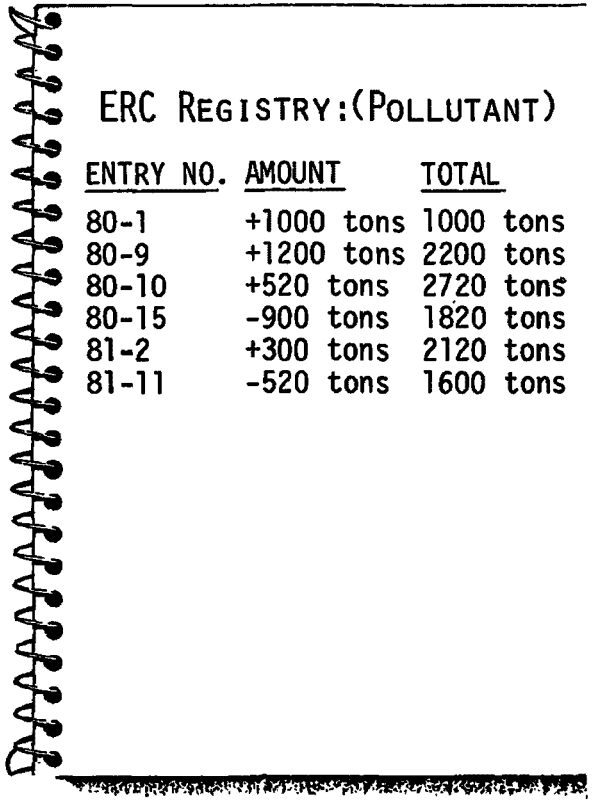


ENTRY
No. ERC REGISTRY LOG

80-1 Certificate No. 80-1
Issued to (owner)
Source location (address)
For (amount)
Of (pollutant)
Source Class
Permit Ref.
Certificate Ref.

80-2 Certificate No. 80-2
Issued to (owner)
Source location (address)
For (amount)
Of (pollutant)
Source Class
Permit Ref.
Certificate Ref.

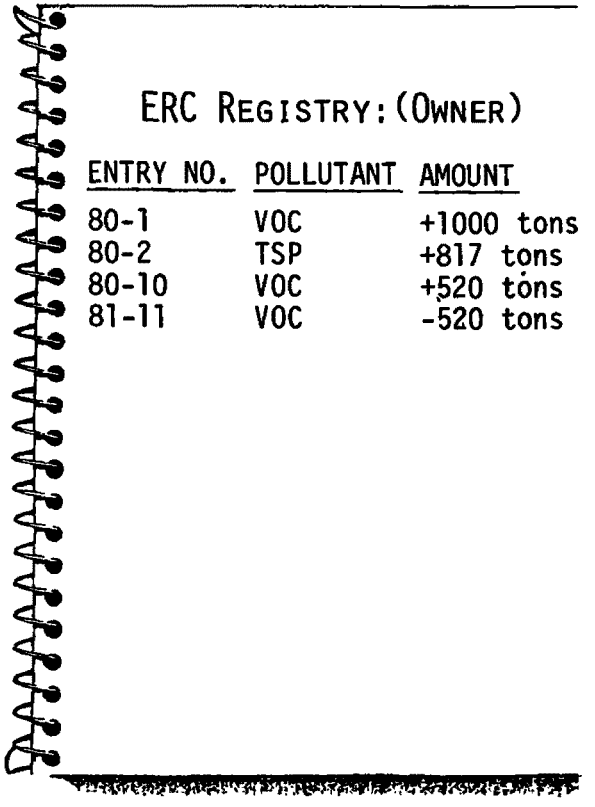
## Part 2: Banked ERCs By Pollutant



ERC REGISTRY: (POLLUTANT)

| ENTRY NO. | AMOUNT | TOTAL |
|---|---|---|
| 80-1 | +1000 tons | 1000 tons |
| 80-9 | +1200 tons | 2200 tons |
| 80-10 | +520 tons | 2720 tons |
| 80-15 | -900 tons | 1820 tons |
| 81-2 | +300 tons | 2120 tons |
| 81-11 | -520 tons | 1600 tons |

## Part 3: Banked ERCs By Owner



ERC REGISTRY: (OWNER)

| ENTRY NO. | POLLUTANT | AMOUNT |
|---|---|---|
| 80-1 | VOC | +1000 tons |
| 80-2 | TSP | +817 tons |
| 80-10 | VOC | +520 tons |
| 81-11 | VOC | -520 tons |

**An Emission Reduction Credit (ERC) Register Allows An APCA To Track And Account For The Certifying, Banking, And Use Of ERCs**

documentation are: (1) a letter that affirms the amount of ERCs created and mentions the possibility of future adjustment to that amount; (2) a copy (carbon or photostat) of the relevant registry page(s); and (3) an ERC certificate (see Exhibit 12).

Each time ERCs are used, a subsequent entry must be made. Again, it is absolutely essential that the central registry be kept up-to-date. Therefore, if ERCs are adjusted an entry should be made debiting the owner's account and noting the reason for the adjustment. Similarly, each time a source uses some of its ERCs, an entry should be made debiting the account to reflect the application of the ERC to a permit and its deletion from the account. Debit entries also should be confirmed by letter.

SUMMARY

To guard against possible misuse of the banking system, careful "tracking" of ERCs is necessary. The registry is analogous to the system of recording the ownership of real estate and its transfer. A registration system for ERCs should be centrally compiled so that conflicts or discrepancies can be minimized or more easily located and resolved. For information purposes, duplicate sets could be placed in key locations throughout the banking region. Presence on the registry should be an invariable requirement for the use of an ERC. To recap, the four steps in this component are:

(1) A central registry must be established including provisions for an ERC log, a cumulative tally of ERCs by pollutant, and the individual account of each owner.

(2) A ratio for converting emission reductions into ERCs must be determined. (This generally will be 1.0.)

(3) Each time an ERC is certified, an initial entry should be made.

(4) Each time ERCs are used, a subsequent entry must be made.

## 2.4 Component 4: Banking and Accounting for Emission Reduction Credits

The actual "banking" or storage component of the system is quite simple and straightforward. It applies to the holding period which begins after ERCs are certified and registered and ends when ERCs are extinguished by conversion into physical pollution allowances and applied to the conditions of a permit. The ERCs are banked until they are used--that is, converted into physical pollution allowances, at which time the ERCs are extinguished.

As ERCs are certified, traded, and used, the appropriate entries must be made in the registry. (See Exhibit 13.)

Any adjustments to ERCs must also be entered into the registry. This situation will not commonly occur, but it is a possibility. During the period after ERCs are certified and registered, and before they are used, an adjustment to reflect changes in the state's overall SIP or ambient air quality standards could be assessed against banked ERCs.

An issue of great importance to sources which might want to bank ERCs is the security

**If trading of ERCs is to be fostered, it is essential to separate the validity of the ERC from the reduced enforceable emissions limit on the producing source. A good faith buyer should not be penalized if the producing source fails to satisfy its legal obligations.**

a new form of "entitlement" sources may have concerns that the credit could be revoked in whole or part under specific circumstances. To address this uncertainty, APCAs should spell out in their banking regulations the specific circumstances under which ERCs may be reduced. The following situations will be discussed here:

- What happens to ERCs if the reduced baseline on which they depend (e.g., on enforceable permit) is violated?
- What happens to ERCs if the SIP is changed in a direction of fewer allowable emissions?

Permit Violations and ERCs

ERCs, by virtue of being certified, are separate from the emission reductions that justified them. This means that ERCs generally should not be constrained or reduced if the creating source violates its (reduced) emission limits. Agencies must enforce those limits, of course. The violation should be treated like any other violation.

It may be possible to establish rules which penalize the producing source for violations. If the source still has possession of the ERCs in the bank, such a penalty could take the form of a reduction in the number of the ERCs. However, once ERCs are traded, the buyer must be protected against any diminution of its ERCs because of violations on the part of the seller.

EXHIBIT 12

# SAMPLE EMISSION REDUCTION CREDIT CERTIFICATE

## EMISSION REDUCTION CREDIT CERTIFICATE No. 80-___

*Issued To:* _____ *Date :* _____

*Pollutant:* _____ *Permit Reference:* _____

*Amount :* _____

*Register Entry No.:* _____ *Source Class & Location :* _____

*This certificate represents ownership of the above amount of emission reduction credits for the specified pollutant. The emission reduction was produced by (method of creation) and confirmed by (APCA). See Permit (permit reference no.). Subject to the rules established by (APCA) for emission reduction credit banking and use, these credits may be used to meet requirements for a new source permit or to comply with emissions limits required in the SIP. Use of some or all of these credits to satisfy permit requirements is subject to the approval of (APCA) according to its rules. All emission reduction credits are subject to pro rata adjustment in the event of changes in national ambient air quality standards or modification of the state implementation plan. No credits may be transferred without the express approval of (APCA).*

_____ _____

*(official signature)* *(official signature)*

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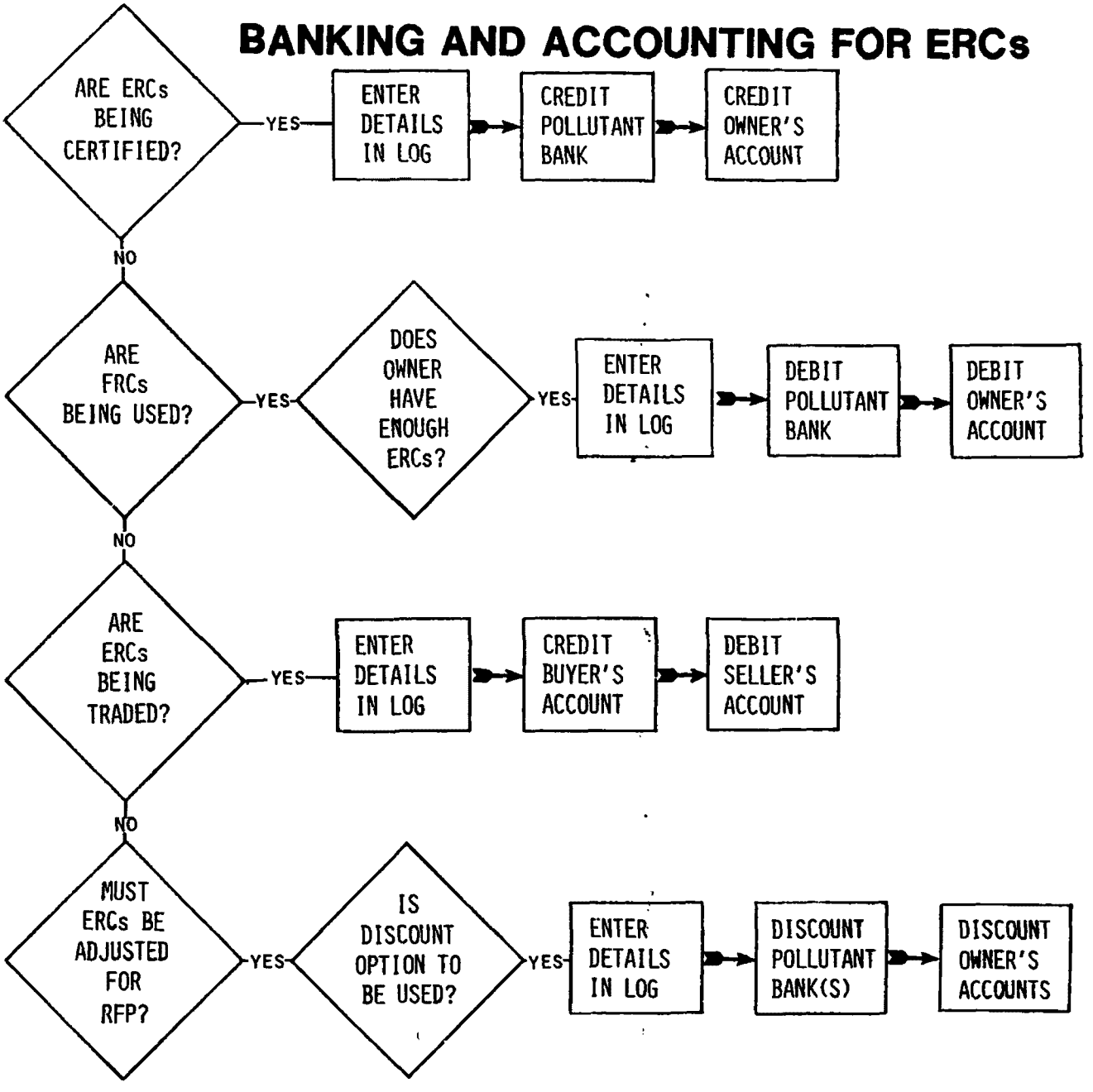
*For Official Use Only: Summary of Use History*

*Certificate No.* _____ *withdrawn for use in Permit No.* _____ .

*Certificate No.* _____ *reissued for remaining credits. See Registry Entry No.* _____.

**EXHIBIT 13**

# BANKING AND ACCOUNTING FOR ERCs



SIP Changes and ERCs

At some time during the existence of an ERC bank, it may be necessary to revise the SIP in order to satisfactorily demonstrate attainment or Reasonable Further Progress (RFP). It is important that banking rules address the issue of what can happen to banked ERCs if RFP is not maintained or if attainment is not accomplished as scheduled.

There are several options available:

(1) a moratorium on use of ERCs until RFP is demonstrated;

(2) increased ratios of ERCs needed to meet different SIP requirements;

(3) ERCs may be discounted pro rata; and

(4) all rights to ERCs may be forefeited.

One or more of these options must be addressed in the banking rules as a contingency in the event that RFP is violated or attainment cannot be demonstrated. As stated earlier, ERCs are not an absolute right to pollute. They are granted to sources which reduce emissions to the degree not already required to meet ambient air standards or RFP. If this assumption on which the ERCs were granted is not satisfied, the state must take corrective action.

**For example, if there were a total of 500 ERCs banked and a SIP revision required a 10 percent reduction in emissions, every ERC would be reduced by 10 percent. Thus, if a source had 100 tons of ERCs, it would have 90 after the reduction; but those 90 would still represent 20 percent of the 450 total ERCs banked.**

In demonstrating attainment, states must consider all banked ERCs. Even though they do not represent actual emissions, ERCs represent potential emissions that will affect air quality. They are like individual growth allowances, premised on the assumption that Clean Air Act standards will still be met if the ERCs are used. If the premise underlying the SIP proves false, ERCs are subject to the adjustments needed to restore the validity of the SIP.

Any of the above-listed options can be used to meet SIP requirements under the Clean Air Act. Each option has different strengths and weaknesses which are discussed next.

The discounting of banked ERCs offers a practicable way to accommodate SIP changes. Under this option, each block of ERCs in the bank is diminished to the same degree that uncontrolled emissions in the inventory must be reduced. The amount of discounting depends on the reductions required for all emissions of that pollutant, including those banked, to satisfy RFP or attainment (e.g., a 10 percent discount). The banked ERCs would bear an equitable part of the burden for re-establishing RFP--existing sources also would be required to reduce emissions as part of the effort to meet the new SIP requirements. In addition, although the quantity of banked ERCs held by firms would be diminished, because air resources have become scarcer, their relative value would likely increase.

The moratorium on use of ERCs does not reduce the amount of ERCs granted. Thus, under this option, sources are guaranteed that the value (i.e., tons/ year) of ERCs will not be diminished. In exchange for this, however, sources may be unable to use these ERCs until RFP has been demonstrated.

An alternative to a moratorium which also focuses on the use of ERCs is to increase allowance ratios. This means that, when RFP or attainment is in jeopardy, the APCA will require more ERCs to satisfy the same emission reduction requirement. Thus, in the context of offsets transactions, the ratio of new emissions to reductions in existing emissions may be increased significantly so as to drive RFP and attainment.

The wholesale forfeit of ERCs when a new SIP is developed would be an extremely unwise choice. The effects of such a rule would likely be devastating on banking programs. Any of the other options should be preferred to this one.

In conclusion, for most communities discounting appears to be the preferred alternative for accommodating banked ERCs to changes in SIPs.

SUMMARY

The process of accounting for ERCs requires the maintenance of a log and entries whenever an ERC is created, traded, or used. In addition, adjustments to ERCs may be entered as discounts if necessary to satisfy RFP.

An APCA has a number of options for dealing with ERCs should it be necessary to obtain additional reduction to satisfy the Reasonable Further Progress requirement. It could develop a discounting or adjustment procedure whereby the number of ERCs in the bank would be reduced by the same proportion as the amount of additional controls required from the emissions inventory.

**For example, if 100 additional tons of control were required when 200 tons were banked and 800 tons were on the inventory, 80 tons of control would be assessed against current emissions and 20 tons against the banked ERCs.**

It may increase the necessary trade-off rate. Alternatively, it may place a temporary moratorium on the use of banked ERCs until Reasonable Further Progress is again attained.

A fourth option--the confiscation of ERCs--is also possible, but would severely inhibit banking activity and undermine the potential benefits of the program. Whatever option is provided, it must be clearly stated in the banking rules.

## 2.5 Component 5: Using Banked Emission Reduction Credits

The final component of a banking system concerns the use of the banked ERCs. The APCA must establish both the administrative steps which will be required when a source seeks to use an ERC against a permit requirement and the appropriate regulatory contexts for the use of ERCs. The APCA's primary goal during this component is to establish procedures which:

- insure the integrity of the banking system;
- facilitate the use of banked ERCs;
- minimize the administrative burden; and
- insure the attainment and maintenance of ambient air quality.

It is extremely important that requirements placed on the use of ERCs do not create an undue burden on either the APCA or the source seeking to use its ERCs.

As discussed in Part 1, ERCs may be used as offsets, in bubble applications, or to satisfy PSD requirements.

It should be recognized that banking does not bring the complex task of determining the acceptability of using specific ERCs into the air pollution control system. It is already required for new source offsets and existing source bubbles. Banking may increase the demand for these determinations, which are now done on a case-by-case method. Agencies may then find it more efficient to develop basic guidelines or rules of thumb for use determinations. This could reduce workloads if the guidelines do an adequate job of estimating ambient air effects.

Specific Steps in Using Banked ERCs

There are three specific steps in using ERCs.

(1) The source must propose the use of ERCs to the APCA. ERCs may be used by a source in several contexts:

- to satisfy an existing emission limitation (i.e., a bubble);
- to satisfy a recently instituted, more stringent emission requirement; and
- to satisfy an offset or PSD requirement for a planned new or expanded facility (i.e., new source review).

Regardless of the context, the responsibility of proposing that an ERC be used to satisfy a permit requirement clearly falls on the source. Each of these uses has its own specific requirements that must be satisfied.

(2) The APCA must evaluate the proposed use. It is the responsibility of the APCA to review and rule on the particular use of ERCs proposed by a source. The agency should take several steps to minimize the administrative burden of evaluating these proposals. The use of ERCs will be limited to those situations in which: (1) the pollutant characteristics of the ERC and the proposed use are equivalent (e.g., same pollutant type and equivalent dispersion effects) and (2) the use must not interfere with the demonstration of attainment by the state. The burden for satisfying these requirements falls squarely on the source proposing the use. When the proposed use involves a facility different from the one at which the ERC was created, air quality modeling may be required at the discretion of the APCA. Nevertheless, APCAs are advised to include a fair and consistent decision rule in their banking regulation for determining sufficiency, rather than relying on a case-by-case assessment.

The APCA should publish review guidelines for ERC use. These guidelines should specify: (1) the contexts in which banked ERCs may be used; (2) limits based on pollutant characteristics; and (3) tests required of sources to demonstrate the effect on ambient air quality of using a banked ERC. These guidelines should allow a source in its early planning stages (i.e., before significant time and resources are expended) to determine whether an ERC could be used to partially satisfy a new source or permit requirement. In many instances, it might also be useful for the source and the APCA to hold a preliminary conference to discuss the likelihood that a proposed use will be acceptable and the specific tests required to gain approval. The process by which a source determines the eligibility of a proposed use of an ERC is illustrated in Exhibit 14.

(3) The permit is issued and the SIP changed to reflect use of the ERCs. The APCA is responsible for maintaining accurate records of the creation and use of ERCs and also for insuring that ERCs are reflected in source permits and the SIP. The use of ERCs is similar to that of withdrawing funds from a bank account; at the time ERCs are used, they are extinguished from the ERC registry. To insure consistency with Clean Air Act requirements, the APCA must take the necessary steps to alter its SIP to reflect these changes.

EXHIBIT 14

# PROCEDURE FOR REGULATING THE USE OF ERCs

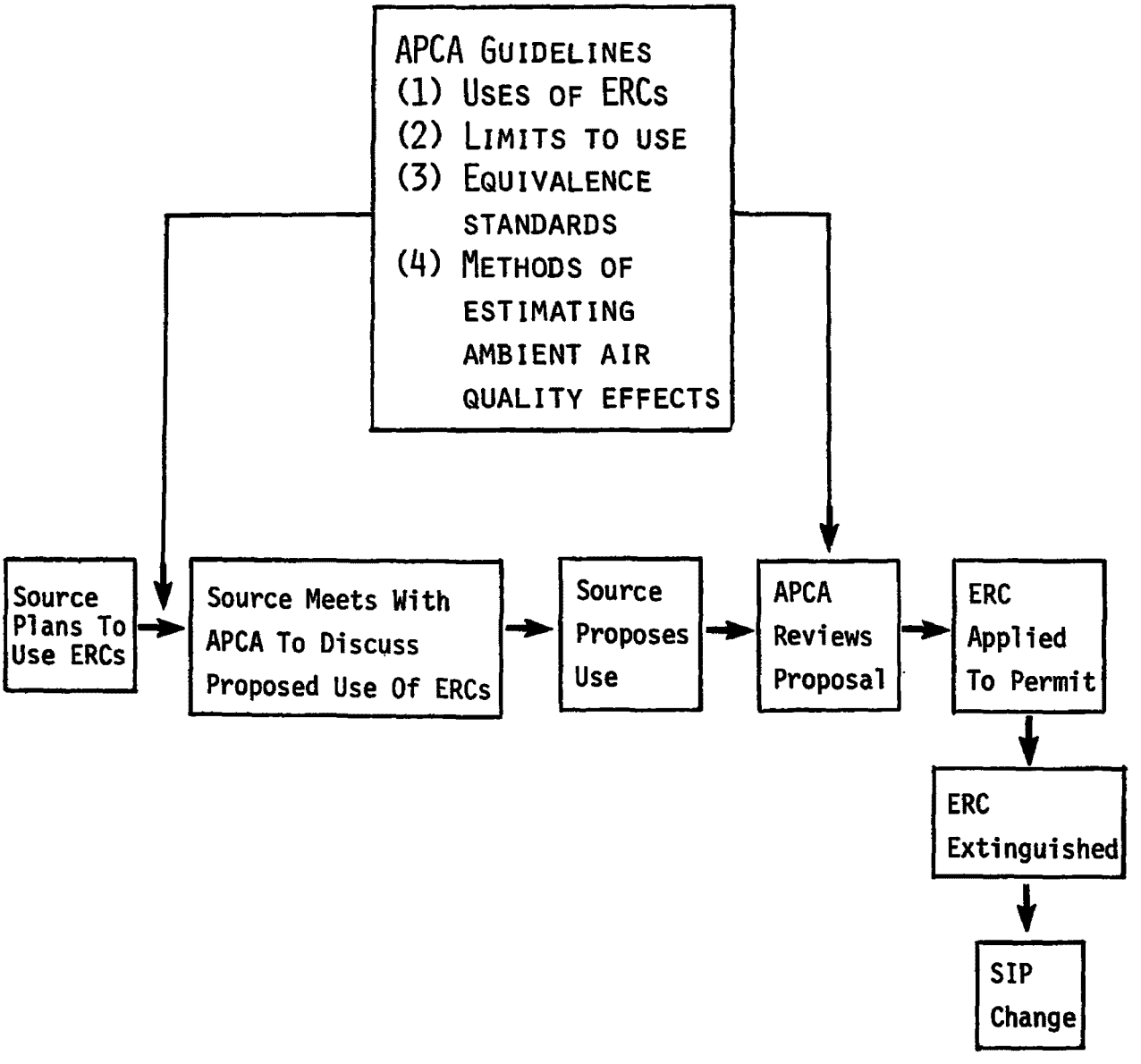


EXHIBIT 15

# USE OF SUFFICIENCY TESTS

## CRITERIA FOR SELECTING TEST

**SIZE**
**LOCATION**
**POLLUTANT**
**TYPE OF REDUCTION**
**AMBIENT AIR PROBLEM**

## SAMPLE TYPE OF TESTS

| | |
|---|---|
| **Simple Ratios** | **1.1 to 1.0** |
| **Complex Ratios** | **1.1 within 5 kilometers** |
| | **1.5 for longer distances** |
| **Simple Modeling** | **Limited to the two sources** |
| **Complex Modeling** | **All sources using a refined grid** |

SUMMARY

This final component, the use of the ERCs, involves three basic steps:

(1) The source proposes to the APCA that ERCs be used to partially satisfy the requirements of a permit.

(2) The APCA reviews the proposed use to make certain that the ERCs will be properly used, but should take steps to minimize the administrative burden associated with this activity.

(3) The ERC is applied to the permit, the SIP is altered, and the ERC is extinguished from the ERC registry.

Possible contexts for which an ERC could be used include a more stringent emission limitation at the source site, an existing emission limitation (i.e., use of the bubble), a proposed expansion at the source site, and a proposed expansion involving offsets or PSD limitations.

# PART 3: ADMINISTERING AN ERC BANKING SYSTEM

The success of an ERC banking program depends not only on good ideas and design, but also on good implementation and administration. The best rule will fail if poorly administered. Two things are necessary: (1) an explicit administrative process and (2) an administrative capability (staff, resources). Regulatory personnel and potential users of the program need to know how banking will be implemented, including the flow, timing, and criteria for technical decisions and appeals. Well-planned schedules, forms, and procedural charts will fulfill this need when coupled with good technical training and administrative skills.

This part of the manual describes the steps for setting up and operating a banking program. The administration of the banking program is closely allied with the program design discussed in Part 2. However, Part 3 deals exclusively with how best to implement and operate the program design selected.

## 3.1 Implementing an ERC Banking System

There are three major requirements for implementing a successful banking program: (1) legal requirements must be satisfied; (2) the foundation of the banking system must be established; and (3) a vigorous effort should be undertaken to encourage participation in the program. These requirements are summarized in Exhibit 15.

### Developing a SIP Rule for Banking

There are three steps that must be taken to build a proper legal foundation for a banking system.

- A banking rule must be developed by the state or SIP designated locality.
- The SIP must be revised to include this new rule.
- The SIP revision must be approved by EPA.

A rule authorizing a banking program must be incorporated in the State Implementation Plan to form the legal basis for creating Emission Reduction Credits. This legal authorization must not be inconsistent with the Clean Air Act, and should address all foreseeable contingencies (e.g., a tightening of the SIP) so that rational investment decisions can be made. This rule could include or be supplemented by regulations to govern the creation, banking, and use of ERCs. It should specify eligibility and ownership qualifications and the protection that would be accorded banked ERCs in the event of a SIP revision. The specification of the rules serve to enhance the certainty essential to firms considering investments in creating ERCs.

Many states authorized banking in their 1977 Part D (i.e., nonattainment) SIP revisions. Few of these states, however, provide the detailed program descriptions essential to a successful banking program. It will be necessary for most states to expand their banking rules and incorporate these revisions into the SIP.

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In developing a detailed banking rule as part of their SIPs, states and areas with delegated SIP authority have a number of options. The banking rule could apply:

- to any area in the state developing a program;
- to only one or more specified areas in the state; or
- different rules could apply to different areas in the state.

To provide for consistency and prevent "jurisdiction shopping," states would be advised not to adopt the last alternative.

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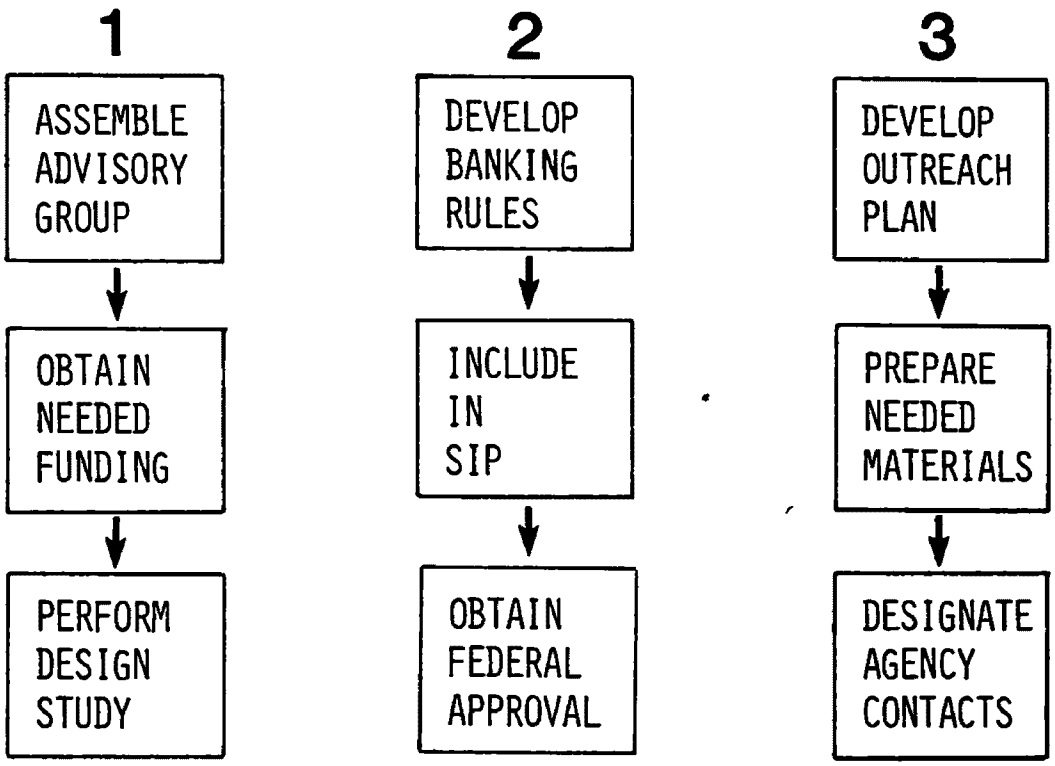
### Establishing the Foundations of the Banking System

There are two steps that should be taken to establish the foundations of the banking system. These steps will affect the banking system rules and how the support for the system is structured.

- Assemble an advisory group to provide input in designing the banking system rules. The purpose of this step is to provide broad-based input to the rules which govern how an ERC may be created, who may create an ERC, and under what circumstances ERCs may be used. Organizations that should be represented in this advisory group include the regional air quality planning body, the council of governments or metropolitan planning organization, the state or local economic development agency, industry associations, and environmental groups. If a trading program is later initiated, it is likely that one of these organizations would be the sponsor.
- Obtain the necessary financing for implementing the banking system. Financing is needed primarily to fund the initial study of the system's design. This need not be an elaborate

EXHIBIT 16

# IMPLEMENTING AN ERC BANKING PROGRAM




analysis quantifying the benefits of banking to a community. Instead, it should focus on assessment of the area needs and select among the number of optional elements of the banking system described in this manual. Support for the actual operations of the system should rely exclusively on user fees assessed against sources seeking to bank and use Emission Reduction Credits.

**An elaborate study *will not* produce a good system. Involving all affected parties *early* in the design process and compromising to meet all needs will.**

Supporting the Banking System

A good rule and good administrative procedures are necessary but not sufficient conditions for a successful banking program. Firms need to be informed of the opportunities of banking and may require assistance in order to use the banking system.

As its primary marketing tool, the air pollution control agency or cosponsoring organization (e.g., COG, business association) should develop an information packet to send to firms that lays out a step-by-step flow chart, along with checklists, example forms, and other pertinent information describing how the system operates. Expected processing times for each of the administrative steps should be estimated, along with a list of contact personnel in the agency who can provide further information. The APCA itself should develop a flow chart of steps, personnel responsibilities, and tracking systems to keep applications moving in an orderly and timely fashion.

## 3.2 Operating an ERC Banking System

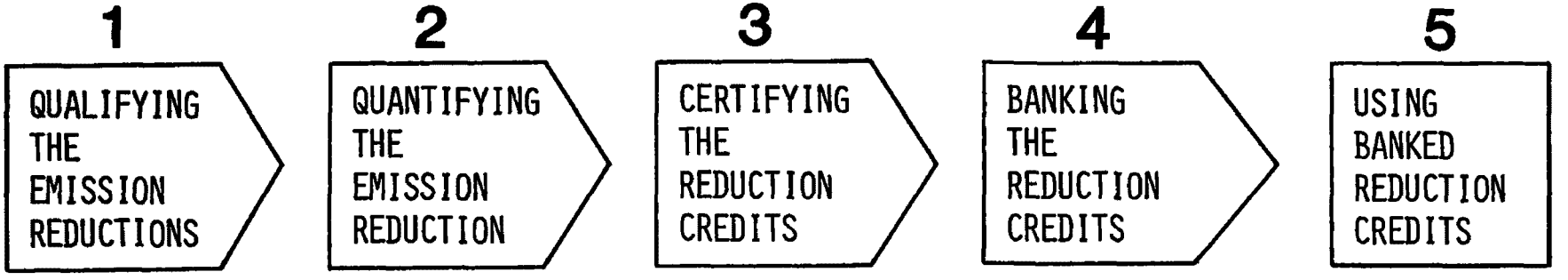
There are three major requirements for successfully operating an ERC banking system: (1) effective administration of the system; (2) technical assistance to current and potential participants, and; (3) feedback from participants about ways the banking system can be improved.

Effective Administration of the System

The interrelation of the five components of the banking system make the administration of each component important to the others. An administrative system should be defined for each component to insure that the banking

EXHIBIT 17

# THE FIVE COMPONENTS OF THE BANKING SYSTEM




**Key Activities**

(1) APCA must establish Ownership & Eligibility qualifications.

(2) Firms must decide to participate.

**Key Activities**

(1) APCA must quantify reduction and make it legally binding in the SIP.

**Key Activities**

(1) APCA must convert reductions into credits and issue certificates.

(2) APCA must establish a registry to track all credits issued or used.

**Key Activities**

(1) APCA must keep the registry current.

(2) APCA must establish rules for applying SIP changes or new RFP requirements to banked credits.

**Key Activities**

(1) APCA must establish rules for using the banked credits.

(2) Firms must decide how & when to use the credits.



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system as a whole will operate effectively. Exhibit 16 summarizes the administrative tasks facing the agency in operating a banking program.

1. Qualifying Emission Reductions. There are several steps the APCA performs in administering this component. These require the APCA to establish rules about how an acceptable emission reduction can be created and who may create emission reductions that will be eligible for certification as ERCs.

The APCA must go through a rule-making procedure that will provide notice of the proposed rules to affected parties and will give them an opportunity to comment. When the rules are in final form, copies should be sent to all interested parties and should be included as part of any marketing efforts. The appropriate qualifications for participating in banking should be clearly stated in the banking rules.

In summary, the first component's administrative structure should include the following:

(1) plans to disseminate proposed banking rules including provisions regarding qualifications;

(2) schedule of hearings to receive comments on proposed rules; and

(3) plans to disseminate final rules.

2. Confirming Emission Reductions. There are six steps which the APCA performs in administering this component. These steps involve responding to requests from sources and quantifying the emission reductions for conversion into ERCs.

The source, if it is not operating under a permit, must establish an existing baseline of actual emissions against which emission reductions may be measured.

The next step involves providing sources with an estimate of what amount of emission reductions will be confirmed. This estimate must be made by the staff of the APCA, but should, where possible, be calculated using rules of thumb.

After creating an emission reduction, a source must notify the APCA to apply for ERCs. This notification should be made on a form containing information such as ownership, location, type of pollutant, how the emission reduction was created, and the estimated amount of emission reduction created. After the source has taken the initiative and contacted the APCA, the APCA should use its expertise, through its staff members, to confirm the magnitude and permanence of the emission reduction (the source would be notified of the documentation it would have to provide).

The reduction would be made enforceable by altering the source's permit and seeking incorporation of the permit change into the SIP. The SIP change is not something the source applicant can effect unilaterally. The source, however, is responsible for providing the necessary documentation to state and EPA officials.

In summary, the second component's administrative structure should include the following:

(1) procedures for determining an emissions baseline, including a form which can be used by a source to request an operating permit from the APCA;

(2) procedures for individual sources to request and obtain an estimate of the ERCs to be granted as the result of a proposed emission control action;

(3) a form by which a source can notify the APCA that an emission reduction has been created;

(4) procedures for officially confirming the magnitude and permanence of the emission reduction, including guidelines about what information and documentation should be provided by the source;

(5) procedures for changing a permit to reflect the emission reduction created by the source; and

(6) guidelines including what documentation is necessary, for seeking a SIP change.

3. Certifying Emission Reduction Credits. Three steps must be taken by the APCA in administering this component. All are related to an accounting and recording procedure which is designed to provide the official record of ERCs created, banked, and used. The APCA must establish a central registry as the official repository of this information. (See Part 2.3 for greater detail).

In limited cases the APCA may want to apply a ratio to convert emission reductions into ERCs. When used, this ratio must not be arbitrary and should be based on criteria relating to the accuracy of the estimate and the kind, source, and pollutant class of the emission reduction created. The ratio should be determined on the basis of such concerns as the uncertainty in measurement and the effect of geographical characteristics on ambient air quality.

The primary action in this step is the certification and registration of ERCs to the account of the producing source.

In summary, the third component's administrative structure should include the following:

(1) the APCA must establish a central registry to serve as the official record of ERC creation (and use);

(2) if applicable, an appropriate conversion ratio should be developed and applied for classes of emission reductions; and

(3) the ERCs must be entered into the central registry.

4. Banking the ERCs. Banking begins when the ERC is registered and continues until it is withdrawn and used. During this period, some events may occur which require certain adjustments to be made in the quantity of ERCs registered. These adjustments generally will be on a pro rata basis and can be made with little difficulty. The only administrative requirements are that the registry be maintained on a continuing basis and that someone enter any pro rata adjustments which may occur. If trading is allowed, ownership changes must also be entered in the registry.

In summary, the fourth component's administrative structure will include:

(1) continual maintenance of the central registry, to account for all ERCs; and

(2) specific responsibilities assigned to the designated registrar to enter adjustments in the registry as needed to satisfy RFP or a new SIP.

5. Using the ERCs. The APCA is responsible for administering five aspects of this component. The APCA must provide ERC holders with guidelines about the use (when, how, where, by whom) of ERCs. These guidelines should be promulgated as formal rules by which the APCA is bound. The APCA must provide a convenient means for ERC holders to notify the APCA of their proposed use of the credits. As in the second component, a form can be devised precisely for this purpose. The APCA should have some internal procedures established for evaluating the proposed use in light of the established rules.

The appropriate permit change must be made and debits entered into the central registry when the APCA approves the proposed provision. Finally, the SIP must be revised to reflect the changed permit.

In summary, the fifth component's administrative structure should include:

(1) regulations regarding the use of ERCs should be incorporated into the original banking rule and the SIP;

(2) a form to be used by ERC holders when notifying the APCA of a proposed use;

(3) internal APCA procedures for accommodating proposed uses with the established rules;

(4) procedures for making permit changes; and

(5) processing of SIP revision.

This administrative framework, based on the five components of the ERC banking system, is illustrated in Exhibit 16. Administrative effectiveness is necessary in operating the banking system, but the provision of technical assistance also helps assure its success.

## 3.3 Technical Assistance to Users of the Banking System

The lack of familiarity with the banking system on the part of most potential participants will require widespread technical assistance as soon as the banking system has been introduced. Presumably, as the banking system is used and experience in its operation grows, less technical assistance will be necessary. However, there always will be individual users who need to solve a unique problem or who have not been reached by initial educational efforts. Some examples of technical assistance include:

- Helping sources obtain the necessary funding. The APCA may want to provide potential buyers and sellers with written guidance about opportunities for financing the production of ERCs. EPA currently is developing financing manuals which can be used for this purpose.

- Informing sources of methods of producing ERCs. The APCA could make general information available to sources explaining different methods of producing ERCs.

There will be many particular issues that could confuse a potential user of the banking system. To the extent that the APCA is prepared to help resolve this confusion, the banking system's potential for success is enhanced.

Feedback From Participants

Administrative systems usually can be improved if experience under the system is frequently reviewed to correct previously undetected shortcomings. During the design and implementation stage, it is difficult to anticipate every need which the banking system should address or to identify errors made in the planning and implementation stages. For this reason, the APCA should develop a feedback or review mechanism and make it an integral part of the banking system. This mechanism does not have to involve an elaborate evaluation of the banking system. Instead, it should answer two basic questions:

(1) Is the banking system meeting the needs of those who have used the system?

(2) Has the banking system met the goals for which it was established?

In part 1.3, several reasons for establishing a banking system were suggested. During the review process, it should be useful to make

specific inquiries whether these advantages have been realized in practice:

- Has banking provided the APCA with greater flexibility in developing and implementing a SIP?
- Has banking provided the APCA a means to promote economic growth without impairing environmental quality?
- Has banking proved to be an incentive for firms to reduce emissions below the required level?
- Has banking encouraged innovation in air pollution control technology?
- Have firms found banking useful in their planning efforts?
- Has banking enabled firms to minimize the cost of complying with emission standards?

These questions suggest a two-tiered feedback mechanism: the appraisal of sources who have used or considered using the banking system and the appraisal of involved APCA staff. It is not necessary that the questions all be answered favorably; the exercise is supposed to pinpoint where the system is not performing as expected. When the malfunctions are identified, remedial measures can be taken.

For purposes of illustration, one approach to providing feedback is outlined below.

- Input from users or potential users of the banking system could be sought at two different points in time.

  (1) Immediately after a banking transaction has been completed, the source involved could be given the opportunity to suggest changes in the banking process. This input can be standardized by development of a form soliciting suggestions and asking specific questions.

  (2) On a regular basis (for example, semi-annually), an advisory panel of source representatives could be convened to provide input about the effectiveness of the banking system. Membership can be on a rotating basis, but some members of the panel should be from sources which have had recent experience with the banking system.

- Internal review by APCA staff should be an ongoing process.

  (1) A staffer should be designated to handle the input from users of the system. This would coordinate the individual and collective inputs from sources.

  (2) A regular review session (quarterly or semi-annually) should be conducted with input from all relevant APCA staff. The overall performance of the banking system should be assessed, problem areas identified, and changes proposed.

Regardless of how it is structured, some review mechanism should be established so that the banking system can be kept responsive to the goals for which it was designed.

## 3.4 The Relationship of Banking to Trading

This manual has presented the components of banking, a process by which firms creating surplus emission reductions can "bank" them for later use to satisfy permit requirements. The focus of the manual has intentionally been limited to the banking of Emission Reduction Credits. At the same time, the proposed banking system has been constructed in a manner which facilitates the trading or transfer of ERCs between different legal entities.

The only significant difference between a system which allows for banking and a system which allows both banking and trading of ERCs is that the latter entails a comprehensive program for encouraging the sale of ERCs between sources.

Exhibit 17 illustrates the additional step required to allow trading. Following the certifying, registering, and banking of ERCs, a firm possessing ERCs would be permitted to sell these to another legal entity. This transfer of ownership could occur directly through a private sale, or through some form of public auction. The APCA could directly control the trading or simply be responsible for establishing trading rules and performing an oversight function.

For a thorough discussion of the mechanics of designing and implementing a trading system, the reader is referred to a brochure that explains trading in greater detail and to three separate manuals available from the EPA Banking and Trading Project. Each of these manuals explains a distinct trading system--a private trading system using brokers, a public auction system, and a central trading system. (See Appendix B.)

In designing its banking system, the APCA should not overlook the potentially significant benefits of extending the system to include trading. A system which includes both banking and trading offers several additional advantages:

- The Achievement of Environmental Quality at Lower Total Cost: Firms would be able to purchase Emission Reduction Credits from other firms in situations where the costs are less expensive than creating their own ERCs.
- The Establishing of a More Robust Market for ERCs: By allowing firms to sell their ERCs, a market for ERCs should be created. More buyers and

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sellers should mean increased price competition and less delay and uncertainty in obtaining ERCs.

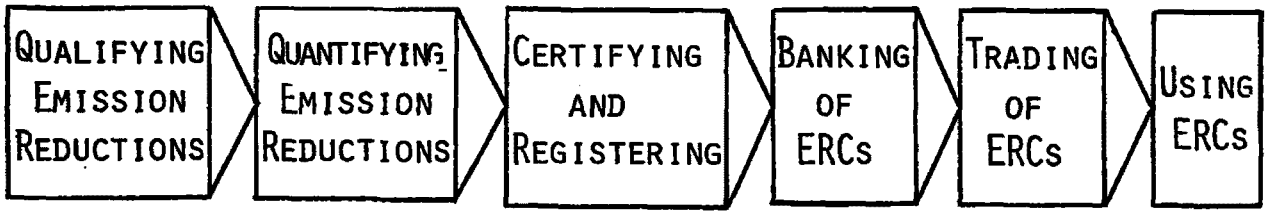
- Permit New Firms to Enter a Market: Firms not currently located in an area may be required to purchase offsets to satisfy nonattainment or PSD requirements. The availability of ERCs for purchase should facilitate their entry into a region.

Because of the advantages of trading, it behooves the APCA to work with other groups in their areas and to move forward as quickly as possible to extend banking to include the development of a system for trading of ERCs. Economic development agencies, regional planning organizations, and industry associations are examples of groups likely to take the lead in organizing a trading program.

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**EXHIBIT 18**

# EXPANDING A BANKING SYSTEM TO INCLUDE TRADING




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## MANUALS DESCRIBING ALTERNATIVE TRADING SYSTEMS

## ARE AVAILABLE FROM THE EPA.

# APPENDIX A: Glossary

Key terms, as used in this manual, are defined below.

- Actual Emissions: The level of pollution emitted by a source. Actual emissions may differ from "allowable" emissions, which is the level specified in a source's permit or in the State Implementation Plan (SIP). Whether allowable or actual emissions is used in determining the baseline against which emissions reductions are measured will depend on the manner in which the SIP was developed (see Exhibits 6 and 7 and accompanying text). In almost every state, actuals will form the baseline for measuring emission reductions.

- Air Pollution Control Authority (APCA). The public agency at the state and/or local level which has primary responsibility for implementing the Clean Air Act. The APCA is the most likely institution to implement a banking system--this manual reflects that assumption. It is possible however for a distinct body, e.g., the Chamber of Commerce, air quality planning organization, or an economic development agency, to develop a banking program, but only with the close cooperation and support of the APCA which will be responsible for implementing the program.

- Allowable Emissions. The level of emissions permitted by the terms of a source's permit or in the SIP. The question is whether allowable emissions is the appropriate baseline for measuring emission reductions. Only if current (i.e., actual) emissions are less than allowable emissions and the State Implementation Plan was designed using the emission levels specified in permits, would a source be allowed credit for this difference.

- Allowance Ratio. This ratio is applied during the process by which banked ERCs are converted for use to partially satisfy the terms of a permit requirement. The allowance ratio is a reduction in the quantity of ERCs to satisfy ambient air quality requirements.

- Bank. The term and its derivatives are used in three different senses in this manual. The term is not used to describe an institution where deposits, withdrawals, and other transactions are consummated. Therefore, there is not any one institution which can be described as the Emission Reduction Credit "bank". The three uses are:

  (1) Banking is used to describe the process by which a firm initially reduces its emissions and applies for ERCs. The banking process continues until ERCs are extinguished through use.

  (2) Banked refers to the status of an ERC after it has been certified, but before it has been used.

  (3) Bank refers to the pool of ERCs currently entered in the central registry.

- Baseline. The level of emissions below which a source must reduce its emissions in order to constitute an "emission reduction." Generally, it is the more stringent requirement of actual or allowable emissions. But this will depend on how the State Implementation Plan was developed and the specific policy of that locale in satisfying the requirements of the Clean Air Act.

- Bubble. EPA's alternative emission reduction option which, when incorporated into a State Implementation Plan, allows a source to reduce control requirements at one point by increasing controls correspondingly at another. The bubble can be applied both within a single plant and between different plants in the same area. The policy is explained in detail in the Federal Register, Vol. 44, p. 71780 (Dec. 11, 1979).

- Certificate. The air pollution control agency issues certificates representing ownership of specific ERCs which appear on the register and thus are banked. These certificates are for recordkeeping purposes and are not legally transferrable.

- Confirmation. Air pollution control agency's verification given to a source's creation of an emission reduction. Confirmation is the second component of the banking process and comes only after all questions about the emission reduction (i.e., quantity, permanence, how created, etc.) have been resolved. A confirmed reduction in emissions would result in a change in the terms of a source's permit.

- Controls. The means by which an emission reduction is achieved. Generally this would be used in reference to the technological controls installed by a source--scrubbers, electrostatic precipitators, or other abatement equipment. However, it includes any measure taken to create emission reductions--shutdowns, cutbacks, altered work practices, alteration of inputs or production processes, etc.

- Conversion Ratio. The ratio is applicable to the process whereby an emission reduction is converted to an emission reduction credit (ERC). It is the fraction or percentage used to determine the number of ERCs which will be credited to an account. The ratio will generally be 1.0, and is determined after considering many factors

including any classification schemes applied to sources and pollutants, the characteristics of the ER, measurement certainty, etc.

- Emission Offset. A regulatory device designed to allow economic growth in an area where a national ambient air quality standard (NAAQS) has not been attained. The actual offset is obtained by securing a decrease in an existing source's emissions to compensate for emissions of a new or expanding source seeking to locate in a nonattainment area (see Section 173 of the Clean Air Act.)

- Emission Reductions (ERs). The physical reduction of emissions by a source. To be eligible for conversion into ERCs, this reduction must be below the measurable baseline or currently required level of emissions and must be permanently enforceable.

- Emission Reduction Credits (ERCs). The commodity which is "banked" and can later be used by a source to satisfy the required emission limits contained in its permit. The ERC is the end product of the conversion of emission reductions. ERCs are used by being converted back into physical pollution units using an allowance ratio in a manner consistent with other requirements (e.g., new or expanding source emission offsets, bubble). It is crucial that the distinction between emission reductions and ERCs be maintained--they are not synonymous.

- Minor Source. A subcategory of sources with emissions below some threshold defined by states in their SIPs (e.g., 25 tons per year). This subcategory of existing sources is typically excluded from permit requirements, and thus lack a baseline against which emission reductions can be ascertained.

- Monitoring. The measurement and recordation of emissions which occurs over time. The purpose of monitoring is both to obtain a measurement and to ensure the permanency of the emission reduction. Monitoring can involve in-stack devices which measure emissions or devices which measure input or output parameters.

- Nonattainment Area. A geographic area designated by EPA to be in violation of national ambient air quality standard (NAAQS). A major new or expanding source seeking to locate in a nonattainment area must arrange for sufficient offsets to insure that Reasonable Further Progress toward attainment of NAAQS is achieved.

- Nonconventional Sources. A subcategory of sources characterized by emissions which are not directly measurable. Nonconventional sources include roads, storage piles, and the like. Because of this characteristic, these sources are generally not subject to permits and an APCA may decide to exclude them from the banking system.

- Permit. The emission restrictions placed by the Air Pollution Control Authority on a specific source. The permit may specify a specific emission limit, require a percent removal of a pollutant, or dictate a particular work practice. Where possible, the permit conditions should be used as the baseline for evaluating emission reduction. The permit terms are also generally related to the SIP and thus any change in a permit requires a corresponding change in the SIP.

- Reasonable Further Progress or RFP. The requirement under the Clean Air Act that areas designated nonattainment achieve annual incremental steps toward satisfying ambient air quality standards by the designated deadlines.

- Registry. The books in which the banking system's activities are recorded and which serve as the accounting record for the issuance and use of ERCs. In a banking system, these books generally will be maintained by the APCA. They clarify ownership issues and facilitate the search process for needed reductions.

- Source. A source is any building, structure, facility, or installation which emits any air pollutant. A source may include several specific emitting points, but is limited to those owned by a single legal entity.

- State Implementation Plan (SIP). The legal mechanism, subject to EPA approval, by which a state proposes to achieve and maintain the ambient air quality requirements of the Clean Air Act.

- Trade. The transfer or sale of ERCs from one legal entity to another in some kind of market situation subject to APCA review and approval. Companion manuals deal with the potential for trading ERCs and how such a system complements the banking system.

- User Fee. Charges levied against sources that make use of the banking system. The charges can be used to defray operating expenses or to fully fund the operation of the banking program.

# APPENDIX B: Selected Annotated Bibliography

The following titles, along with a more extensive annotated biblography are available by mailing in the enclosed form or by contacting directly:

Emission Reduction Banking and Trading Project
U.S. Environmental Protection Agency (PM-220)
401 M Street, S.W.
Washington, D.C. 20460

AA001 Emission Reduction Banking and Trading Project, Office of Planning and Evaluation, U.S. Environmental Protection Agency. Annotated Biblography.

A complete listing and explanation of publications dealing with banking, the bubble, and other economic incentives to control air pollution.

BA120 Hoffman, John S. Economic Advantages of Emission Banking Systems. Prepared for the U.S Environmental Protection Agency.

Examines why emission reduction banking and trading systems save firms money, and offers a few design options available to states and localities in developing cost-effective systems.

BA200 ICF Incorporated. Emission Reduction Banking & Trading: Concept Paper. Prepared for the Emission Reduction Banking and Trading Project, Office of Planning and Evaluation, the U.S. Environmental Protection Agency, January 1, 1980.

An excellent introduction and overview of banking and trading. Divided into three parts, the first section of this paper generally discusses the concepts of banking and trading, their key terms, and analogies and precedents. The second part describes in detail the five stages of an emissions reduction, banking and trading system. The final part discusses the advantages and disadvantags of three trading systems: public auction, central trading system, and private trading.

BG250 ICF Incorporated. An Introduction to Trading. Prepared for the Emission Reduction Banking and Trading Project, Office of Planning and Evaluation, U.S. Environmental Protection Agency, October 1980.

This document presents a detailed discussion of the role of trading in a banking system. It explains the many advantages of trading and summarizes and compares the alternative designs for trading systems.

BG300 ICF Incorporated. Public Auction Trading System Manual. Prepared for the Emission Reduction Banking and Trading Project Office, Office of Planning and Evaluation, U.S. Environmental Protection Agency, October 1980.

BG400 ICF Incorporated. Central Price Trading System Manual. Prepared for the Emission Reduction Banking and Trading Project Office, Office of Planning and Evaluation, U.S. Environmental Protection Agency.

BG500 ICF Incorporated. Private/Brokerage Trading System Manual. Prepared for the Emission Reduction and Trading Project Office, Office of Planning and Evaluation, U.S. Environmental Protection Agency.

These three trading manuals explain the specific steps required to design and operate a trading system. They discuss the many design options, financing considerations, and institutional concerns in developing a trading program.

BG600 Emission Reduction Banking and Trading Project, Office of Planning and Evaluation, U.S. Environmental Protection Agency. Issues Paper on Shutdowns.

This issues paper discusses the options available to states and localities in treating emission reductions from shutdowns. It explores the legal, economic, and policy implications of these alternatives.

BA700 Emission Reduction Banking and Trading Project, Office of Planning and Evaluation, U.S. Environmental Protection Agency. Model Banking Rule.

This model rule illustrates and explains specific provisions that can be included as part of a banking system. Examples of banking rules already adopted by communities are included.

AH100 Public Financing Manual for the Creation and Purchase of Emission Reduction Credits. Prepared by Economic Analysis Division, Office of Planning and Evaluation, U.S. Environmental Protection Agency.

Firms and communities investigating available public options for financing the creation and purchase of emission reductions will find this manual especially useful. For each option, the manual discusses the following program issues and requirements: objective, funding level, form of funding, eligibility requirements, eligible activities, the range and average level of financial assistance, the funding cycle, and examples of previously funded activities. The manual also includes a brief framework for evaluating the individual options.

AH110 Putnam, Hayes & Bartlett, Inc. Private Financing Manual for the Creation and Purchase of Emission Reduction Credits. Prepared by Economic Analysis Division, Office of Planning and Evaluation, U.S. Environmental Protection Agency.

Some of the feasible private alternatives this manual identifies for financing emission reductions are stock options, limited partnerships, bank loans, stock, leveraged leasing, pollution control revenue bonds, and debentures. The manual catalogs these options by sources of funds, financing costs, qualifying requirements, management restrictions, legal and political implications, historical uses of the financing option, and option execution procedures. It also presents criteria for evaluating the options.

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# BANKING AND TRADING ORDER BLANK

Send to:

**Emission Reduction Banking & Trading Project**
**U.S. Environmental Protection Agency (PM-220)**
401 M Street, S.W.
Washington, D.C. 20460

Name _____

Address _____

Phone _____ Occupation _____

____ AA001 Annotated Bibliography
____ BA120 Economic Advantages Paper
____ BA200 Banking and Trading Concept Paper
____ BA600 Issues Paper on Shutdowns
____ BA700 Model Banking Rule

____ BA250 An Introduction to Trading
____ BA300 Public Auction Trading System Manual
____ BA400 Central Trading System Manual
____ BA500 Private/Brokerage Trading System Manual
____ AH100 Public Financing Manual
____ AH110 Private Financing Manual

**_____I want to be on your mailing list**

# Exhibit BB. Arvin/Lamont CERP Appendix C: Source Apportionment and Community Inventories (June 9, 2022)

# APPENDIX C

## Source Apportionment and Community Inventories

## Arvin/Lamont CERP

San Joaquin Valley Air Pollution Control District

# APPENDIX C
# ARVIN/LAMONT SOURCE ATTRIBUTION

## STATIONARY SOURCE EMISSIONS INVENTORY

A community emissions inventory is the compilation of criteria pollutant and air toxics emissions data from air pollution sources that are within the community. The stationary source community emissions inventory includes emissions of volatile organic compounds & reactive organic gases (VOC/ROG), oxides of nitrogen (NOx), particulate matter of 2.5 microns (PM2.5), and toxic air contaminants (e.g. diesel PM).

The District has longstanding experience working with regulated facilities and collecting emissions inventory data on an annual basis from these facilities. The District's current criteria emissions inventory reporting processes provides an annual assessment of emissions from permitted facilities in the Valley. The inventory collection process begins early in the calendar year by requesting emissions-related information from stationary sources of pollution for the prior calendar year, using streamlined processes and forms developed over years of experience working with industry. The District then verifies or calculates emissions based on the inventory data received by the regulated facilities in the Valley.

### *Methodology*

The emissions inventory represents actual emissions from stationary sources. The actual emissions are typically based one of the following general quantification methods:

Emissions (ton-pollutant/yr) = Process Rate (ton-throughput/yr)
x Emission Factor (ton-pollutant/ton-throughput)

Emissions (ton-pollutant/yr) = Fuel Use (gal combusted/yr)
x Emission Factor (ton-pollutant/gal combusted)

Emissions (ton-pollutant/yr) = Fuel Use (SCF combusted/yr)
x Emission Factor (SCF combusted)

The District relies on the regulated facility owners and operators to submit accurate process rate and/or fuel use data, and identify the approved emission factors as well identify necessary updates to those emission factors. Emission factors are established based on the best available information, and according to the following overarching data quality hierarchy:

1. Continuous Emissions Monitoring (CEM) on the equipment
2. Periodic source test on the equipment
3. Manufacturer's guarantee on the equipment
4. Continuous measurement for similarly configured emission sources
5. Source testing data for similar emission sources
6. Permitted emission limits and emission factors established during permitting actions and listed on the permit.

7. AP-42 or other state-approved industry derived emission factors.

### *Stationary Source Facility-Level Emissions Inventories*

Based on the emissions inventory gathering process described above, the table below summarizes the emissions inventory for each District permitted facility in the Arvin/Lamont Community for year 2019.

Table Notes:

- The facilities listed below are identified in alphabetical order.
- Not all facilities emit all pollutants
- Facilities first operating in 2019 have no reported inventory for 2019
- Values have been rounded to two decimal places

***Table 1: Year 2019 Emissions Inventory for District Permitted Facilities***

| REGION | ID | Facility Name | NOx (tons/yr.) | ROG (tons/yr.) | PM2.5 (tons/yr.) |
|---|---|---|---|---|---|
| S | 18 | KERN COUNTY GENERAL SERVICES | 0.00 | 0.00 | 0.00 |
| S | 37 | KERN OIL & REFINING CO. | 50.59 | 44.27 | 15.33 |
| S | 238 | H & S CHEVRON FOOD MART INC | 0.06 | 0.20 | 0.07 |
| S | 333 | BENNETT PETROLEUM - DIGIORGIO | 0.00 | 0.00 | 0.00 |
| S | 679 | S & S MINI MART, INC | 0.00 | 0.11 | 0.00 |
| S | 866 | EDSAL SANDUSKY CORP | 0.00 | 0.59 | 0.57 |
| S | 890 | CABALLERO OPERATIONS LLC. - KRAUTER | 0.00 | 0.00 | 0.00 |
| S | 890 | CABALLERO OPERATIONS LLC. - VINEYARD | 0.00 | 0.00 | 0.00 |
| S | 890 | CABALLERO OPERATIONS LLC. - BANKLINE+SYMONS | 0.00 | 0.00 | 0.00 |
| S | 1137 | THE TERMO CO - KNOWLES | 0.00 | 0.59 | 0.00 |
| S | 1137 | THE TERMO CO - MTN VIEW | 0.57 | 1.46 | 0.07 |
| S | 1137 | THE TERMO CO - BRITE | 0.00 | 1.09 | 0.00 |
| S | 1157 | PACIFIC BELL TELEPHONE CO (DBA AT&T CA) | 0.02 | 0.01 | 0.00 |
| S | 1161 | PACIFIC BELL TELEPHONE CO (DBA AT&T CA) | 0.03 | 0.00 | 0.00 |
| S | 1529 | BENNETT PETROLEUM - MOTT | 0.00 | 0.00 | 0.00 |
| S | 1529 | BENNETT PETROLEUM - DIGIORGIO | 0.00 | 0.00 | 0.00 |
| S | 1580 | SOUTHERN VALLEY CHEMICAL CO | 0.00 | 0.01 | 0.00 |
| S | 1603 | SERGIO'S AUTO BODY & PAINT | 0.00 | 0.02 | 0.00 |
| S | 1647 | BLACKBURN OIL CO | 0.00 | 0.38 | 0.00 |
| S | 1688 | RUBEN'S AUTO BODY LLC | 0.00 | 0.07 | 0.01 |
| S | 2137 | 7-ELEVEN INC | 0.00 | 0.36 | 0.00 |
| S | 2247 | KERN COUNTY PUBLIC WORKS | 0.00 | 0.00 | 0.00 |
| S | 2257 | BLACKBURN OIL CO | 0.00 | 0.03 | 0.00 |
| S | 2286 | US OIL & GAS - PIERCY+ALLEN | 0.00 | 0.00 | 0.00 |
| S | 2357 | FASTRIP OIL CO | 0.00 | 0.72 | 0.00 |
| S | 2359 | JACO HILL CO | 0.00 | 0.34 | 0.00 |
| S | 2372 | JACO HILL CO | 0.00 | 0.28 | 0.00 |
| S | 2374 | JAMIESON HILL | 0.00 | 0.81 | 0.00 |
| S | 2383 | JAMIESON HILL | 0.00 | 1.18 | 0.00 |
| S | 2621 | QUALITY MARKET & FUEL | 0.06 | 0.15 | 0.07 |
| S | 2635 | CABALLERO OPERATIONS LLC. | 0.00 | 0.01 | 0.00 |
| S | 2729 | KERN COUNTY FIRE STATION #51 | 0.00 | 0.00 | 0.00 |
| S | 2784 | GAS 4 LESS | 0.00 | 0.20 | 0.00 |
| S | 2811 | LAMONT PUBLIC UTILITY DIST | 0.05 | 0.00 | 0.00 |
| S | 2841 | GRIMMWAY ENTERPRISES INC | 0.66 | 0.41 | 0.54 |

| REGION | ID | Facility Name | NOx (tons/yr.) | ROG (tons/yr.) | PM2.5 (tons/yr.) |
|---|---|---|---|---|---|
| S | 2905 | RECOLOGY BLOSSOM VALLEY ORGANICS - SOUTH | 0.00 | 71.61 | 0.63 |
| S | 2927 | AT&T MOBILITY | 0.00 | 0.00 | 0.00 |
| S | 2961 | HUNTER EDISON OIL DEVELOPMENT - TRINO | 0.03 | 0.08 | 0.00 |
| S | 2985 | PETRO RESOURCES INC - FH | 0.00 | 0.00 | 0.00 |
| S | 3031 | CITY OF ARVIN | 0.00 | 0.01 | 0.00 |
| S | 3036 | SEQUOIA EXPLORATION - STOCKTON | 0.00 | 0.10 | 0.00 |
| S | 3036 | SEQUOIA EXPLORATION - SIMPSON | 0.00 | 0.00 | 0.00 |
| S | 3036 | SEQUOIA EXPLORATION - JEWETT | 0.00 | 0.00 | 0.00 |
| S | 3130 | FRANKS CABINET SHOP | 0.00 | 0.00 | 0.41 |
| S | 3197 | GRIMMWAY FARMS | 0.12 | 0.05 | 0.09 |
| S | 3331 | R & R RESOURCES LLC - TVT | 0.00 | 0.00 | 0.00 |
| S | 3402 | LOHGARH SAMRA INC | 0.00 | 0.92 | 0.00 |
| S | 3433 | ARVIN SANITARY LANDFILL | 1.97 | 0.36 | 0.10 |
| S | 3629 | VEOLIA WATER NORTH AMERICA | 0.11 | 0.01 | 0.00 |
| S | 3914 | TS LEASING OPERATIONS INC - WIBLE+HO STRICKLER | 0.00 | 0.12 | 0.00 |
| S | 4035 | JOE'S RENTALS | 0.00 | 0.00 | 0.00 |
| S | 4051 | BURGER KING #9637/OCEAN ELEVEN INC | 0.03 | 0.00 | 0.00 |
| S | 4162 | KERN OIL & REFINING | 0.27 | 0.61 | 0.02 |
| S | 4169 | CITY OF ARVIN | 0.01 | 0.00 | 0.00 |
| S | 4182 | ARVIN COMMUNITY SERVICES DISTRICT | 0.07 | 0.00 | 0.01 |
| S | 4270 | VERIZON WIRELESS - ARVIN | 0.00 | 0.00 | 0.00 |
| S | 5224 | DM CAMP & SONS - RANCH #8 | 0.00 | 0.00 | 0.00 |
| S | 5225 | DM CAMP & SON - RANCH #8 - SECTION 28 | 0.00 | 0.00 | 0.00 |
| S | 6637 | G3 DAIRY | 0.00 | 0.00 | 0.00 |
| S | 6684 | LAMONT PUBLIC UTILITY DISTRICT | 0.02 | 0.00 | 0.00 |
| S | 6758 | KIRSCHENMAN ENTERPRISES INC #4 | 0.00 | 0.00 | 0.00 |
| S | 6820 | DILLON & SONS DBA THE BARN #4 | 0.00 | 0.20 | 0.00 |
| S | 7013 | EVERGREEN HEALTHCARE - ARVIN | 0.04 | 0.00 | 0.00 |
| S | 7076 | PETRO CAPITAL RESOURCES LLC - JEWETT | 0.00 | 0.00 | 0.00 |
| S | 7076 | PETRO CAPITAL RESOURCES LLC - RICHARDS | 0.13 | 0.01 | 0.01 |
| S | 7125 | ULRICH BARN BUILDERS OF CALIFORNIA | 0.00 | 0.18 | 0.57 |
| S | 7235 | GOGO LLC | 0.09 | 0.01 | 0.00 |
| S | 7345 | VERIZON WIRELESS (DT LAMONT) | 0.00 | 0.00 | 0.00 |
| S | 7378 | EAST TRAVEL PLAZA LLC | 0.03 | 1.91 | 0.00 |
| S | 7452 | LAMONT PUBLIC UTILITY DISTRICT | 0.06 | 0.00 | 0.00 |
| S | 7537 | VERIZON WIRELESS - NORTH LAMONT | 0.00 | 0.00 | 0.00 |
| S | 7543 | PANAMA RANCH | 0.00 | 0.00 | 0.00 |

| REGION | ID | Facility Name | NOx (tons/yr.) | ROG (tons/yr.) | PM2.5 (tons/yr.) |
|---|---|---|---|---|---|
| S | 7648 | KERN OIL & REFINING CO | 0.01 | 0.00 | 0.00 |
| S | 7832 | ANTHONY VINEYARDS INC | 0.00 | 0.00 | 0.00 |
| S | 8167 | CHARTER COMMUNICATIONS | 0.01 | 0.00 | 0.00 |
| S | 8312 | GRIFFIN RESOURCES LLC - FRICK | 0.00 | 0.00 | 0.00 |
| S | 8334 | STENDERUP AG PARTNERS | 0.00 | 0.00 | 0.00 |
| S | 8338 | WHEELER RIDGE SHELL STATION | 0.00 | 0.19 | 0.00 |
| S | 8533 | TASTEFUL SELECTIONS | 0.02 | 0.00 | 0.00 |
| S | 8573 | LAMONT PUBLIC UTILITY DISTRICT | 0.01 | 0.00 | 0.00 |
| S | 8620 | LAMONT PUBLIC UTILITIES DISTRICT | 0.06 | 0.00 | 0.00 |
| S | 9035 | ARVIN PETROLEUM INC. #47008 | 0.00 | 0.84 | 0.00 |
| S | 9091 | 7 DAYS MINI MART | 0.00 | 0.00 | 0.00 |
| S | 9255 | MOUNTAIN VIEW RESOURCES LLC - RICHARDS | 0.00 | 0.00 | 0.00 |
| S | 9255 | MOUNTAIN VIEW RESOURCES LLC - TRINIDAD | 0.00 | 0.00 | 0.00 |
| S | 9591 | ARVIN COMMUNITY SERVICES DISTRICT | 0.00 | 0.00 | 0.00 |
| S | 9592 | ARVIN COMMUNITY SERVICES DISTRICT | 0.00 | 0.00 | 0.00 |

### *Forecasting Emissions - Stationary Sources:*

For assessing future growth for the years 2026 and 2031, the CARB used growth and control factors to adjust the current 2017 inventory and project emissions into 2026 and 2031 future years.

Projected emissions were calculated using the 2017 emissions inventory as the base year to project emissions for 2026 and 2031. The 2017 emissions inventory values were used to project emissions by multiplying these emissions by the ratio of the growth factors and control factors for each process. The emissions are projected for each permitted unit and then totaled to grow the facility emissions. The following equation represents the formula for forecasting emissions in a future year from a specific emissions unit (i.e. equipment type):

$$\text{2026 NOx (ton/yr)} = \text{2017 NOx emissions} \times [(\text{2026 NOx GF} \div \text{2017 NOx GF}) \times (\text{2026 NOx CF} \div \text{2017 NOx CF})]$$

Where,
GF= Growth factor
CF = Control factor


PEXH 000759

### *Forecasted Stationary Source Emissions Inventories*

Based on the forecasting process described above, Tables 2 and 3 below summarize the emissions inventory for each District permitted facility in the Arvin/Lamont Community for years 2026 and 2031.

***Table 2: Year 2026 Projected Emissions Inventory for District Permitted Facilities***

| Region | ID | Facility Name | NOX (tons/yr.) | ROG (tons/yr.) | PM2.5 (tons/yr.) |
|---|---|---|---|---|---|
| S | 18 | KERN COUNTY GENERAL SERVICES | 0.00 | 0.00 | 0.00 |
| S | 37 | KERN OIL & REFINING CO. | 40.35 | 41.50 | 15.35 |
| S | 238 | H & S CHEVRON FOOD MART INC | 0.05 | 0.14 | 0.06 |
| S | 333 | BENNETT PETROLEUM - DIGIORGIO | 0.00 | 0.00 | 0.00 |
| S | 679 | S & S MINI MART, INC | 0.00 | 0.08 | 0.00 |
| S | 866 | EDSAL SANDUSKY CORP | 0.00 | 0.70 | 0.68 |
| S | 890 | CABALLERO OPERATIONS LLC. - KRAUTER | 0.00 | 0.00 | 0.00 |
| S | 890 | CABALLERO OPERATIONS LLC. - VINEYARD | 0.00 | 0.00 | 0.00 |
| S | 890 | CABALLERO OPERATIONS LLC. - BANKLINE+SYMONS | 0.00 | 0.00 | 0.00 |
| S | 1137 | THE TERMO CO - KNOWLES | 0.00 | 0.44 | 0.00 |
| S | 1137 | THE TERMO CO - MTN VIEW | 0.25 | 1.09 | 0.05 |
| S | 1137 | THE TERMO CO - BRITE | 0.00 | 0.82 | 0.00 |
| S | 1157 | PACIFIC BELL TELEPHONE CO (DBA AT&T CA) | 0.02 | 0.01 | 0.00 |
| S | 1161 | PACIFIC BELL TELEPHONE CO (DBA AT&T CA) | 0.05 | 0.01 | 0.00 |
| S | 1529 | BENNETT PETROLEUM - MOTT | 0.00 | 0.00 | 0.00 |
| S | 1529 | BENNETT PETROLEUM - DIGIORGIO | 0.00 | 0.00 | 0.00 |
| S | 1580 | SOUTHERN VALLEY CHEMICAL CO | 0.00 | 0.01 | 0.00 |
| S | 1603 | SERGIO'S AUTO BODY & PAINT | 0.00 | 0.02 | 0.00 |
| S | 1647 | BLACKBURN OIL CO | 0.00 | 0.38 | 0.00 |
| S | 1688 | RUBEN'S BODY AND AUTO PAINTING | 0.00 | 0.08 | 0.02 |
| S | 2137 | 7-ELEVEN, INC | 0.00 | 0.26 | 0.00 |
| S | 2247 | KERN COUNTY PUBLIC WORKS | 0.00 | 0.00 | 0.00 |
| S | 2257 | BLACKBURN OIL COMPANY | 0.00 | 0.29 | 0.00 |
| S | 2286 | US OIL & GAS | 0.00 | 0.00 | 0.00 |
| S | 2357 | FASTRIP OIL COMPANY | 0.00 | 0.51 | 0.00 |
| S | 2359 | JACO HILL CO | 0.00 | 0.34 | 0.00 |
| S | 2372 | JACO HILL COMPANY | 0.00 | 0.43 | 0.00 |
| S | 2374 | JAMIESON HILL | 0.00 | 0.81 | 0.00 |
| S | 2383 | JAMIESON HILL | 0.00 | 1.40 | 0.00 |
| S | 2621 | MARY LAMONT INC. | 0.05 | 0.10 | 0.06 |
| S | 2635 | ATLANTIC OIL COMPANY | 0.00 | 0.00 | 0.00 |

| Region | ID | Facility Name | NOX (tons/yr.) | ROG (tons/yr.) | PM2.5 (tons/yr.) |
|---|---|---|---|---|---|
| S | 2729 | KERN COUNTY FIRE STATION #51 | 0.00 | 0.00 | 0.00 |
| S | 2784 | GAS 4 LESS | 0.00 | 0.14 | 0.00 |
| S | 2811 | LAMONT PUBLIC UTILITY DIST | 0.04 | 0.00 | 0.00 |
| S | 2841 | GRIMMWAY ENTERPRISES INC | 0.55 | 0.43 | 0.57 |
| S | 2905 | RECOLOGY BLOSSOM VALLEY ORGANICS - SOUTH | 0.00 | 73.23 | 0.27 |
| S | 2927 | AT&T MOBILITY | 0.00 | 0.00 | 0.00 |
| S | 2961 | HUNTER EDISON OIL DEVELOPMENT | 0.01 | 0.05 | 0.00 |
| S | 2985 | PETRO RESOURCES INC - FH | 0.00 | 0.00 | 0.00 |
| S | 3031 | CITY OF ARVIN | 0.00 | 0.01 | 0.00 |
| S | 3036 | SEQUOIA EXPLORATION - STOCKTON | 0.00 | 0.08 | 0.00 |
| S | 3036 | SEQUOIA EXPLORATION - SIMPSON | 0.00 | 0.00 | 0.00 |
| S | 3036 | SEQUOIA EXPLORATION - JEWETT | 0.00 | 0.00 | 0.00 |
| S | 3130 | FRANKS CABINET SHOP | 0.00 | 0.00 | 0.40 |
| S | 3197 | GRIMMWAY FARMS | 0.10 | 0.05 | 0.10 |
| S | 3331 | R & R RESOURCES LLC | 0.00 | 0.00 | 0.00 |
| S | 3402 | LOHGARH SAMRA INC | 0.00 | 0.64 | 0.00 |
| S | 3433 | ARVIN SANITARY LANDFILL | 1.28 | 0.36 | 0.08 |
| S | 3629 | VEOLIA WATER NORTH AMERICA | 0.10 | 0.01 | 0.00 |
| S | 3914 | TS LEASING OPERATIONS INC | 0.00 | 0.10 | 0.00 |
| S | 4035 | JOE'S RENTALS | 0.00 | 0.00 | 0.00 |
| S | 4051 | BURGER KING #9637/OCEAN ELEVEN INC | 0.04 | 0.00 | 0.00 |
| S | 4162 | KERN OIL & REFINING | 0.24 | 0.65 | 0.02 |
| S | 4169 | CITY OF ARVIN | 0.01 | 0.01 | 0.00 |
| S | 4182 | ARVIN COMMUNITY SERVICES DISTRICT | 0.06 | 0.00 | 0.01 |
| S | 4270 | VERIZON WIRELESS - ARVIN | 0.00 | 0.00 | 0.00 |
| S | 5224 | DM CAMP & SONS - RANCH #8 | 0.00 | 0.00 | 0.00 |
| S | 5225 | DM CAMP & SON - RANCH #8 - SECTION 28 | 0.00 | 0.00 | 0.00 |
| S | 6637 | G3 DAIRY | 0.00 | 0.00 | 0.00 |
| S | 6684 | LAMONT PUBLIC UTILITY DISTRICT | 0.02 | 0.00 | 0.00 |
| S | 6758 | KIRSCHENMAN ENTERPRISES INC #4 | 0.00 | 0.00 | 0.00 |
| S | 6820 | DILLON & SONS DBA THE BARN #4 | 0.00 | 0.14 | 0.00 |
| S | 7013 | EVERGREEN HEALTHCARE - ARVIN | 0.04 | 0.00 | 0.00 |
| S | 7076 | PETRO CAPITAL RESOURCES LLC - JEWETT | 0.00 | 0.00 | 0.00 |
| S | 7076 | PETRO CAPITAL RESOURCES LLC - RICHARDS | 0.06 | 0.00 | 0.01 |
| S | 7125 | ULRICH BARN BUILDERS OF CALIFORNIA | 0.00 | 0.18 | 0.57 |
| S | 7235 | GOGO LLC | 0.00 | 0.00 | 0.00 |
| S | 7345 | VERIZON WIRELESS (DT LAMONT) | 0.00 | 0.00 | 0.00 |
| S | 7378 | EAST TRAVEL PLAZA, LLC | 0.03 | 1.51 | 0.00 |

| Region | ID | Facility Name | NOX (tons/yr.) | ROG (tons/yr.) | PM2.5 (tons/yr.) |
|---|---|---|---|---|---|
| S | 7452 | LAMONT PUBLIC UTILITY DISTRICT | 0.06 | 0.00 | 0.00 |
| S | 7537 | VERIZON WIRELESS - NORTH LAMONT | 0.00 | 0.00 | 0.00 |
| S | 7543 | PANAMA RANCH | 0.00 | 0.00 | 0.00 |
| S | 7648 | KERN OIL & REFINING COMPANY | 0.01 | 0.00 | 0.00 |
| S | 7832 | ANTHONY VINEYARDS INC | 0.00 | 0.00 | 0.00 |
| S | 8167 | CHARTER COMMUNICATIONS | 0.01 | 0.00 | 0.00 |
| S | 8312 | GRIFFIN RESOURCES, LLC | 0.00 | 0.00 | 0.00 |
| S | 8334 | STENDERUP AG PARTNERS | 0.00 | 0.00 | 0.00 |
| S | 8338 | WHEELER RIDGE SHELL STATION | 0.00 | 0.13 | 0.00 |
| S | 8533 | TASTEFUL SELECTIONS | 0.03 | 0.00 | 0.00 |
| S | 8573 | LAMONT PUBLIC UTILITY DISTRICT | 0.08 | 0.00 | 0.00 |
| S | 8620 | LAMONT PUBLIC UTILITIES DISTRICT | 0.06 | 0.00 | 0.00 |
| S | 9035 | ARVIN PETROLEUM INC. #47008 | 0.00 | 0.59 | 0.00 |
| S | 9091 | 7 DAYS MINI MART | 0.00 | 0.00 | 0.00 |
| S | 9255 | MOUNTAIN VIEW RESOURCES LLC - RICHARDS | 0.00 | 0.00 | 0.00 |
| S | 9255 | MOUNTAIN VIEW RESOURCES LLC - TRINIDAD | 0.00 | 0.00 | 0.00 |
| S | 9591 | ARVIN COMMUNITY SERVICES DISTRICT | 0.00 | 0.00 | 0.00 |
| S | 9592 | ARVIN COMMUNITY SERVICES DISTRICT | 0.00 | 0.00 | 0.00 |

***Table 3: Year 2031 Projected Emissions Inventory for District Permitted Facilities***

| Region | ID | Facility Name | NOX (tons/yr.) | ROG (tons/yr.) | PM2.5 (tons/yr.) |
|---|---|---|---|---|---|
| S | 18 | KERN COUNTY GENERAL SERVICES | 0.00 | 0.00 | 0.00 |
| S | 37 | KERN OIL & REFINING CO. | 35.44 | 40.35 | 15.38 |
| S | 238 | H & S CHEVRON FOOD MART INC | 0.05 | 0.12 | 0.06 |
| S | 333 | BENNETT PETROLEUM - DIGIORGIO | 0.00 | 0.00 | 0.00 |
| S | 679 | S & S MINI MART, INC | 0.00 | 0.07 | 0.00 |
| S | 866 | EDSAL SANDUSKY CORP | 0.00 | 0.76 | 0.73 |
| S | 890 | CABALLERO OPERATIONS LLC. - KRAUTER | 0.00 | 0.00 | 0.00 |
| S | 890 | CABALLERO OPERATIONS LLC. - VINEYARD | 0.00 | 0.00 | 0.00 |
| S | 890 | CABALLERO OPERATIONS LLC. - BANKLINE+SYMONS | 0.00 | 0.00 | 0.00 |
| S | 1137 | THE TERMO CO - KNOWLES | 0.00 | 0.38 | 0.00 |
| S | 1137 | THE TERMO CO - MTN VIEW | 0.21 | 0.94 | 0.04 |
| S | 1137 | THE TERMO CO - BRITE | 0.00 | 0.71 | 0.00 |
| S | 1157 | PACIFIC BELL TELEPHONE CO (DBA AT&T CA) | 0.02 | 0.01 | 0.00 |
| S | 1161 | PACIFIC BELL TELEPHONE CO (DBA AT&T CA) | 0.05 | 0.01 | 0.00 |
| S | 1529 | BENNETT PETROLEUM - MOTT | 0.00 | 0.00 | 0.00 |
| S | 1529 | BENNETT PETROLEUM - DIGIORGIO | 0.00 | 0.00 | 0.00 |
| S | 1580 | SOUTHERN VALLEY CHEMICAL CO | 0.00 | 0.01 | 0.00 |
| S | 1603 | SERGIO'S AUTO BODY & PAINT | 0.00 | 0.02 | 0.00 |
| S | 1647 | BLACKBURN OIL CO | 0.00 | 0.38 | 0.00 |
| S | 1688 | RUBEN'S BODY AND AUTO PAINTING | 0.00 | 0.08 | 0.02 |
| S | 2137 | 7-ELEVEN, INC | 0.00 | 0.22 | 0.00 |
| S | 2247 | KERN COUNTY PUBLIC WORKS | 0.00 | 0.00 | 0.00 |
| S | 2257 | BLACKBURN OIL COMPANY | 0.00 | 0.27 | 0.00 |
| S | 2286 | US OIL & GAS | 0.00 | 0.00 | 0.00 |
| S | 2357 | FASTRIP OIL COMPANY | 0.00 | 0.44 | 0.00 |
| S | 2359 | JACO HILL CO | 0.00 | 0.34 | 0.00 |
| S | 2372 | JACO HILL COMPANY | 0.00 | 0.38 | 0.00 |
| S | 2374 | JAMIESON HILL | 0.00 | 0.81 | 0.00 |
| S | 2383 | JAMIESON HILL | 0.00 | 1.23 | 0.00 |
| S | 2621 | MARY LAMONT INC. | 0.05 | 0.09 | 0.06 |
| S | 2635 | ATLANTIC OIL COMPANY | 0.00 | 0.00 | 0.00 |
| S | 2729 | KERN COUNTY FIRE STATION #51 | 0.00 | 0.00 | 0.00 |
| S | 2784 | GAS 4 LESS | 0.00 | 0.13 | 0.00 |
| S | 2811 | LAMONT PUBLIC UTILITY DIST | 0.04 | 0.00 | 0.00 |
| S | 2841 | GRIMMWAY ENTERPRISES INC | 0.52 | 0.46 | 0.62 |

| Region | ID | Facility Name | NOX (tons/yr.) | ROG (tons/yr.) | PM2.5 (tons/yr.) |
|---|---|---|---|---|---|
| S | 2905 | RECOLOGY BLOSSOM VALLEY ORGANICS - SOUTH | 0.00 | 79.49 | 0.28 |
| S | 2927 | AT&T MOBILITY | 0.00 | 0.00 | 0.00 |
| S | 2961 | HUNTER EDISON OIL DEVELOPMENT | 0.01 | 0.04 | 0.00 |
| S | 2985 | PETRO RESOURCES INC - FH | 0.00 | 0.00 | 0.00 |
| S | 3031 | CITY OF ARVIN | 0.00 | 0.01 | 0.00 |
| S | 3036 | SEQUOIA EXPLORATION - STOCKTON | 0.00 | 0.07 | 0.00 |
| S | 3036 | SEQUOIA EXPLORATION - SIMPSON | 0.00 | 0.00 | 0.00 |
| S | 3036 | SEQUOIA EXPLORATION - JEWETT | 0.00 | 0.00 | 0.00 |
| S | 3130 | FRANKS CABINET SHOP | 0.00 | 0.00 | 0.40 |
| S | 3197 | GRIMMWAY FARMS | 0.10 | 0.06 | 0.10 |
| S | 3331 | R & R RESOURCES LLC | 0.00 | 0.00 | 0.00 |
| S | 3402 | LOHGARH SAMRA INC | 0.00 | 0.56 | 0.00 |
| S | 3433 | ARVIN SANITARY LANDFILL | 1.35 | 0.38 | 0.08 |
| S | 3629 | VEOLIA WATER NORTH AMERICA | 0.10 | 0.01 | 0.00 |
| S | 3914 | TS LEASING OPERATIONS INC | 0.00 | 0.09 | 0.00 |
| S | 4035 | JOE'S RENTALS | 0.00 | 0.00 | 0.00 |
| S | 4051 | BURGER KING #9637/OCEAN ELEVEN INC | 0.04 | 0.00 | 0.00 |
| S | 4162 | KERN OIL & REFINING | 0.20 | 0.69 | 0.02 |
| S | 4169 | CITY OF ARVIN | 0.01 | 0.00 | 0.00 |
| S | 4182 | ARVIN COMMUNITY SERVICES DISTRICT | 0.06 | 0.00 | 0.01 |
| S | 4270 | VERIZON WIRELESS - ARVIN | 0.00 | 0.00 | 0.00 |
| S | 5224 | DM CAMP & SONS - RANCH #8 | 0.00 | 0.00 | 0.00 |
| S | 5225 | DM CAMP & SON - RANCH #8 - SECTION 28 | 0.00 | 0.00 | 0.00 |
| S | 6637 | G3 DAIRY | 0.00 | 0.00 | 0.00 |
| S | 6684 | LAMONT PUBLIC UTILITY DISTRICT | 0.02 | 0.00 | 0.00 |
| S | 6758 | KIRSCHENMAN ENTERPRISES INC #4 | 0.00 | 0.00 | 0.00 |
| S | 6820 | DILLON & SONS DBA THE BARN #4 | 0.00 | 0.12 | 0.00 |
| S | 7013 | EVERGREEN HEALTHCARE - ARVIN | 0.04 | 0.00 | 0.00 |
| S | 7076 | PETRO CAPITAL RESOURCES LLC - JEWETT | 0.00 | 0.00 | 0.00 |
| S | 7076 | PETRO CAPITAL RESOURCES LLC - RICHARDS | 0.05 | 0.00 | 0.01 |
| S | 7125 | ULRICH BARN BUILDERS OF CALIFORNIA | 0.00 | 0.19 | 0.58 |
| S | 7235 | GOGO LLC | 0.00 | 0.00 | 0.00 |
| S | 7345 | VERIZON WIRELESS (DT LAMONT) | 0.00 | 0.00 | 0.00 |
| S | 7378 | EAST TRAVEL PLAZA, LLC | 0.03 | 1.39 | 0.00 |
| S | 7452 | LAMONT PUBLIC UTILITY DISTRICT | 0.06 | 0.00 | 0.00 |
| S | 7537 | VERIZON WIRELESS - NORTH LAMONT | 0.00 | 0.00 | 0.00 |
| S | 7543 | PANAMA RANCH | 0.00 | 0.00 | 0.00 |
| S | 7648 | KERN OIL & REFINING COMPANY | 0.01 | 0.00 | 0.00 |

| Region | ID | Facility Name | NOX (tons/yr.) | ROG (tons/yr.) | PM2.5 (tons/yr.) |
|---|---|---|---|---|---|
| S | 7832 | ANTHONY VINEYARDS INC | 0.00 | 0.00 | 0.00 |
| S | 8167 | CHARTER COMMUNICATIONS | 0.01 | 0.00 | 0.00 |
| S | 8312 | GRIFFIN RESOURCES, LLC | 0.00 | 0.00 | 0.00 |
| S | 8334 | STENDERUP AG PARTNERS | 0.00 | 0.00 | 0.00 |
| S | 8338 | WHEELER RIDGE SHELL STATION | 0.00 | 0.12 | 0.00 |
| S | 8533 | TASTEFUL SELECTIONS | 0.03 | 0.00 | 0.00 |
| S | 8573 | LAMONT PUBLIC UTILITY DISTRICT | 0.08 | 0.00 | 0.00 |
| S | 8620 | LAMONT PUBLIC UTILITIES DISTRICT | 0.06 | 0.00 | 0.00 |
| S | 9035 | ARVIN PETROLEUM INC. #47008 | 0.00 | 0.52 | 0.00 |
| S | 9091 | 7 DAYS MINI MART | 0.00 | 0.00 | 0.00 |
| S | 9255 | MOUNTAIN VIEW RESOURCES LLC - RICHARDS | 0.00 | 0.00 | 0.00 |
| S | 9255 | MOUNTAIN VIEW RESOURCES LLC - TRINIDAD | 0.00 | 0.00 | 0.00 |
| S | 9591 | ARVIN COMMUNITY SERVICES DISTRICT | 0.00 | 0.00 | 0.00 |
| S | 9592 | ARVIN COMMUNITY SERVICES DISTRICT | 0.00 | 0.00 | 0.00 |

# Mobile Source Emissions Inventory

## *Forecasting Emissions - Mobile Sources*

On-road vehicle emissions are calculated using vehicle activity data used in the latest adopted Federal Statewide Transportation Plan (FSTIP) or Regional Transportation Plan (RTP) from the local metropolitan planning organization (MPO)[1]. Criteria air pollutant emissions are estimated by applying emission factors and vehicle distribution from the California Air Resources Board's (CARB) latest Emissions Factor Model (EMFAC2021)[2] to vehicle activity data. Toxic air contaminant emissions are estimated by using CARB's chemical speciation profiles[3] for particulate matter (PM) and Total organic gases (TOG) species. Emissions are aggregated by emission inventory code (EIC) by 1-kilometer (1K) grids for the community.

**Inputs**

- MPO Loaded Network for base year and forecast years from their most current FSTIP or RTP.
- Emission Factors from EMFAC2021
- Statewide 1 kilometer (K) grid as provided by CARB's Modeling Group

**Vehicle Activity Data Pre-processing**

The MPO loaded networks typically contain a base year and certain future target years based on their FSTIP or RTP. To obtain activity data for every year relevant to a Community Emission Reduction Plan (CERP) community from the MPO loaded networks, the vehicle miles traveled (VMT) in the loaded network are interpolated for each year using the loaded networks for the given years provided by the MPO. In the case where the MPO does not include VMT in their loaded network files, the loaded networks are preprocessed by calculating the VMT. The VMT is calculated by multiplying the total daily volume on each link of the MPO loaded network by the length of the link in miles.

**Criteria Air Pollutant Emissions Calculations**

After the loaded networks have been interpolated for all the years relevant to the CERP, emission factors by emission inventory code (EIC) are calculated. An on-road EIC represents a unique combination of vehicle type, fuel type, and emission process type. Emission factors by EIC, as well as vehicle distribution based on county wide or sub-area totals are extracted out of EMFAC2021 and applied to the MPO loaded network for each relevant year. Emission factors are calculated on a

[1] San Joaquin Council of Government 2018 Regional Transportation Plan loaded network (2008 base year projected to 2017)

[2] EMFAC2021 includes information on California's car and truck fleet (e.g., vehicle population, age) and also reflects the emissions benefits of CARB's previously adopted on-road mobile source regulations (e.g., Pavley Standards, Advanced Clean Cars, Truck and Bus, other on-road diesel fleet rules). For more information on EMFAC2021, see https://ww2.arb.ca.gov/sites/default/files/2021-08/emfac2021_technical_documentation_april2021.pdf

[3] California Air Resources Board, Speciation Profiles, see https://www.arb.ca.gov/ei/speciate/speciate.htm

VMT basis, even for EICs that were dependent upon trips or vehicle population.

The following equation was used to calculate emission factors by EIC:

$$EF_{EIC} = E_{EIC} \div VMT_{EIC}$$

Where:

$EF_{EIC}$ = Emission Factor of a particular EIC in a county or sub-area
$E_{EIC}$ = Daily emissions in tons per day for a particular EIC in a county or sub-area
$VMT_{EIC}$ = Daily vehicle miles traveled for a particular EIC in a county or sub-area

Vehicle distribution is calculated by getting the vehicle fraction of each EIC, as shown in the following equation.

$$VF_{EIC} = VMT_{EIC} \div VMT_{ALL}$$

Where:

$VF_{EIC}$ = Vehicle fraction of a particular EIC in a county or sub-area
$VMT_{EIC}$ = Daily vehicle miles traveled for a particular EIC in a county or sub-area
$VMT_{ALL}$ = Total daily vehicle miles traveled for all EICs in a county or sub-area

Once the emission factors and the vehicle fraction are calculated, emissions by EIC are calculated on every road link in the loaded network. To display on-road emissions at the 1K grid level, VMT from the MPO loaded network within the community boundary are summed within each 1K grid, then the EIC emission factors and the vehicle fraction are applied to the total VMT in each 1K grid.

The following equation shows the 1K grid EIC emission calculation:

$$E_{grid} = \sum VMT_{Link} \times EF_{EIC} \times VF_{EIC}$$

Where:

$E_{grid}$ = Emissions in tons per day of a particular criteria pollutant within a 1k grid
$VMT_{Link}$ = VMT on each link with in a particular 1k grid
$EF_{EIC}$ = Emission Factor of a particular EIC in a county or sub-area
$VF_{EIC}$ = Vehicle fraction of a particular EIC in a county or sub-area

On-road emissions are converted from tons per day to tons per year by multiplying vehicle operation days per year by each vehicle category (EMFAC202x category[4]). The vehicle operation days of each EMFAC202x category in each county or sub-area are sourced from EMFAC2021. The operation days can range from 292 days to 347 days a year depending on EMFAC202x vehicle category.

[4] See EMFAC202x vehicle categories on the EMFAC website, https://arb.ca.gov/emfac/project-analysis

### *Toxics Air Contaminant (TAC) Emissions Calculations*

The on-road toxics emissions by EIC by grid cell are calculated using chemical speciation profiles for particulate matter (PM) and Total organic gases (TOG) species. These speciation profiles[5] are developed, maintained, and updated by CARB staff and essentially break down PM and TOG emissions into their individual constituents, including toxics, for each EIC. Then, all the species which are listed in Appendix A-I of AB 2588 Air Toxics "Hot Spots" Emission Inventory Criteria and Guidelines Regulation are filtered out as toxics. The TOG based toxics (e.g., Formaldehyde, Benzene, Xylenes, Naphthalene, 1,3-Butadiene) are estimated using TOG speciation profiles and PM based toxics (metals like Lead, Chromium, Nickel, and Arsenic) are estimated using PM speciation profiles.

There are some toxic species that are not included in the speciation profiles (e.g., Diesel Particulate Matter (DPM) and hexavalent chromium (Cr (VI)) which have potential cancerous effects. Therefore, CARB augmented their community emission inventories to include DPM and Cr (VI) emissions. The exhaust PM emissions from diesel internal combustion engines are considered as DPM. DPM is considered one of the most important toxics due to its cancerous effects. Cr (VI) emissions are estimated as 5% of the total speciated Chromium emissions for each of the liquid fuel combustion sources[6]. Ammonia (NH3) is also one of the toxics that is not in the speciation profiles, the NH3 emissions are taken from the criteria emissions and converted to pounds per year from tons per year.

To compare the relative toxicity of TACs, Toxicity Weighted Emissions (TWE) are calculated for all TACs using health values[7] approved by Office of Environmental Health Hazard Assessment (OEHHA). It is important to note that TWEs are not risks, but weighted emissions useful to compare relative toxicity of TACs. TWEs are calculated by multiplying mass emissions of each TAC with the corresponding health values (e.g., cancer unit risk factor, non-cancer chronic, and acute reference exposure levels) as determined by OEHHA, molecular weight adjustment factors accounting for the molecular weight fraction of a compound associated with the specific health effects, maximum hours of emissions, and normalization factors as described in the formulas below:

1) $Cancer\ TWE_{pol} = \sum EMS_{pol} \times CANURF_{pol} \times MWAF_{pol} \times 7700$

[5] California Air Resources Board, Speciation Profiles, see https://www.arb.ca.gov/ei/speciate/speciate.htm

[6] We assumed that 5% ratio of Cr (VI) to the total Cr, which is within the range ratios of 0.7% - 9% noted in CARB 1986 study, Kang et al, 2016, Rogula-Kozloska, 2018. We also acknowledge that this Cr (VI) ratio to total Cr could vary with different sources (e.g. soil, dust, combustion sources etc.) (Kitsa et al., 1992, Catrambone et al., 2013).

[7] OEHHA Approved health values - https://ww2.arb.ca.gov/sites/default/files/classic//toxics/healthval/contable.pdf.

NOTE: The Inhalation Cancer Unit Risk Factor and the Molecular Weight Adjustment Fraction (MWAF) should be obtained from the approved **"Consolidated Table" of health values** on the above mentioned CARB website. The Chronic Inhalation REL and Acute Inhalation REL values (used below) are also available in the "Consolidated Table".

NOTE: The Molecular Weight Adjustment Fraction (MWAF) is used with Cancer score, for example to get the proportion of the weight of carcinogenic chromium in a compound like barium chromate. The latest OEHHA guidelines also allow the use of the MWAF for non-cancer (chronic and acute) score calculations.

Where,

Cancer $TWE_{pol}$ = Cancer risk based s (TWE) for a pollutant
$CANURF_{pol}$ = Cancer Inhalation Unit Risk Factor for a pollutant
$EMS_{pol}$ = Annual Emissions in lbs/yr for a pollutant
$MWAF_{pol}$ = Molecular Weight Adjustment Fraction for a pollutant

2) $Chronic\ Non\ Cancer\ TWE_{pol} = \sum\ ((EMS_{pol}\ \div 8760)\ \div\ CHRONREL_{pol}) \times 150$

Where,

Chronic Non-Cancer $TWE_{pol}$ = Chronic Non-Cancer risk based (TWE) of a pollutant
$CHRONREL_{pol}$ = Chronic Inhalation reference exposure level (REL) for a pollutant

3) $Acute\ Non\ Cancer\ TWE_{pol} = \sum\ ((EMS_{pol}\ \div 8760)\ \div\ ACUTEREL_{pol}) \times 1500$

Where,

Acute Non-Cancer $TWE_{pol}$ = Acute Non-Cancer risk based (TWE) of a pollutant
$ACUTEREL_{pol}$ = Acute Inhalation reference exposure level (REL) for a pollutant

To avoid double counting of risk from toxic species constituents that occur in whole diesel exhaust sources, only DPM TWE is accounted and excluded the contribution of speciated species for cancer and non-cancer chronic risks. However, one should consider the contribution of the diesel-source species when performing detailed health risks analysis, including for example, the diesel contribution to multi-pathway risk to target organ/endpoint thresholds, and to ambient levels of individual chemicals. Some examples of the species that occur in diesel exhaust and could affect those types of detailed analyses include benzene; ethyl benzene; metals such as arsenic, cadmium, chromium, and nickel; various aldehydes; and others.

### *Off-Road Mobile Sources*

Emissions from off-road sources were estimated using a suite of category-specific models or, where a new model was not available, the OFFROAD2007 model. Many of the newer models were developed to support recent regulations, including in-use off-road equipment, recreational boats, and others.

### *Inventory Base Year*

CARB worked with the local air districts to determine the base year that should be used across the State. CARB selected 2017 as the base year to maintain consistency in the State. Mobile source emissions have been forecasted for years 2019, 2026, and 2031 for the purposes of the CERP.

### *Methodology*

The EMFAC model was used to assess emissions from on-road vehicles. Off-road mobile source emissions are estimated using a new modular approach for different source categories. On-road and off-road models account for the effects of various adopted regulations, technology types, and seasonal conditions on emissions.

Additional information on all CARB's Mobile source Methodologies and categories is available at: https://ww3.arb.ca.gov/msei/msei.htm

### *Summary of On-Road Mobile Source Emissions*

Table 4 below summarizes the total estimated on-road mobile source emissions for each general on-road mobile source category in the Arvin/Lamont Community for 2019:

***Table 4: Year 2019 On-Road Mobile Source Emissions***

| On-Road Mobile Source Category | NOx (tpy) | VOC (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| Heavy Heavy Duty Vehicles | 117.28 | 4.11 | 2.88 |
| Medium Heavy Duty Vehicles | 14.19 | 1.00 | 0.36 |
| Medium Duty Vehicles | 11.33 | 9.73 | 0.25 |
| Light Duty Vehicles | 35.76 | 28.31 | 1.36 |
| Bus | 2.05 | 0.22 | 0.04 |
| Other | 0.98 | 3.76 | 0.02 |
| **Total** | **181.59** | **47.13** | **4.92** |

### *Summary of Off-Road Mobile Source Emissions*

Table 5 below summarizes the total estimated off-road mobile source emissions for each general off-road mobile source category in the Arvin/Lamont Community for 2019:

***Table 5: Year 2019 Off-Road Mobile Source Emissions***

| Off-Road Mobile Source Category | NOx (tpy) | VOC (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| Trains | 7.78 | 0.00 | 0.12 |
| Recreational Boats | 0.00 | 4.47 | 0.00 |
| Off-Road Recreational Vehicles | 0.06 | 3.83 | 0.01 |
| Off-Road Equipment | 61.80 | 29.64 | 2.75 |
| Fuel Storage and Handling | 0.00 | 3.04 | 0.00 |
| Aircraft | 0.19 | 0.00 | 0.00 |
| Farm Equipment | 32.50 | 5.47 | 1.88 |

| Off-Road Mobile Source Category | NOx (tpy) | VOC (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| **Total** | **102.31** | **46.46** | **4.77** |

### *Summary of Mobile Source Emissions*

Table 6 below summarizes total 2019 off-road and on-road mobile source emissions

***Table 6: Year 2019 Mobile Source Emissions Summary***

| Mobile Source Categories | NOx (tpy) | VOC (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| On-Road Mobile Sources | 181.59 | 47.13 | 4.92 |
| Off-Road Mobile Sources | 102.31 | 46.46 | 4.77 |
| **Total** | **283.90** | **93.59** | **9.7** |

The Tables below, summarizes the data used to forecast future-year mobile source emissions by broad source category groupings.

Tables 8 and 9 below summarize the total forecasted on-road emissions in the Arvin/Lamont Community for the years 2026 and 2031:

***Table 8: Year 2026 Projected On-Road Mobile Source Emissions***

| On-Road Mobile Source Categories | NOx (tpy) | VOC (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| Heavy Duty Vehicles | 67.20 | 1.68 | 1.75 |
| Medium Heavy Duty Vehicles | 5.25 | 0.21 | 0.10 |
| Medium Duty Vehicles | 5.21 | 6.96 | 0.23 |
| Light Duty Vehicles | 19.83 | 19.97 | 1.26 |
| Bus | 1.16 | 0.09 | 0.02 |
| Other | 0.74 | 3.45 | 0.02 |
| **Total** | **99.39** | **32.36** | **3.38** |

***Table 9: Year 2031 Projected On-Road Mobile Source Emissions***

| On-Road Mobile Source Categories | NOx (tpy) | VOC (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| Heavy Duty Vehicles | 69.84 | 1.83 | 1.99 |
| Medium Heavy Duty Vehicles | 4.28 | 0.14 | 0.10 |
| Medium Duty Vehicles | 3.36 | 5.58 | 0.21 |
| Light Duty Vehicles | 14.18 | 16.65 | 1.20 |
| Bus | 0.82 | 0.08 | 0.02 |
| Other | 0.62 | 3.31 | 0.01 |
| **Total** | **93.11** | **27.59** | **3.52** |

Tables 10 and 11 below summarize the total forecasted off-road emissions in the

Arvin/Lamont Community for the years 2026 and 2031:

***Table 10: Year 2026 Projected Off-Road Mobile Source Emissions***

| Off-Road Mobile Source Categories | NOx (tpy) | VOC (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| Trains | 7.78 | 0.00 | 0.12 |
| Recreational Boats | 0.00 | 3.76 | 0.00 |
| Off-Road Recreational Vehicles | 0.07 | 3.09 | 0.02 |
| Off-Road Equipment | 44.09 | 27.40 | 1.68 |
| Fuel Storage and Handling | 0.00 | 2.56 | 0.00 |
| Aircraft | 0.14 | 0.00 | 0.00 |
| Farm Equipment | 19.55 | 3.71 | 1.16 |
| **Total** | **71.63** | **40.51** | **2.98** |

***Table 11: Year 2031 Projected Off-Road Mobile Source Emissions***

| Off-Road Mobile Source Categories | NOx (tpy) | VOC (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| Trains | 7.78 | 0.00 | 0.12 |
| Recreational Boats | 0.00 | 3.39 | 0.00 |
| Off-Road Recreational Vehicles | 0.07 | 2.24 | 0.02 |
| Off-Road Equipment | 41.48 | 28.07 | 1.48 |
| Fuel Storage and Handling | 0.00 | 2.48 | 0.00 |
| Aircraft | 0.12 | 0.00 | 0.00 |
| Farm Equipment | 14.24 | 2.98 | 0.84 |
| **Total** | **63.69** | **39.17** | **2.45** |

# Area-Wide Sources Emissions Inventory

Area-wide sources are categories such as consumer products, unpaved road dust, fireplaces, and prescribed burning for which emissions occur over a wide geographic area. Emissions for these categories are estimated by both CARB and the local air districts using various models and methodologies.

For additional information on all area source Methodologies and categories visit CARB and District Web pages:

- https://ww3.arb.ca.gov/ei/areasrc/areameth.htm
- http://www.valleyair.org/Air_Quality_Plans/EmissionsMethods/EmissionsMethods.htm

Table 12 below summarizes the total projected Area Source emissions for each Category in the Arvin/Lamont Community for 2019:

***Table 12: Year 2019 Area Source Emissions for Arvin-Lamont Community***

| Source Categories | NOX (tpy) | ROG (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| **CLEANING AND SURFACE COATINGS** | **0.00** | **12.39** | **0.00** |
| ADHESIVES AND SEALANTS | 0.00 | 1.18 | 0.00 |
| COATINGS AND RELATED PROCESS SOLVENTS | 0.00 | 7.71 | 0.00 |
| DEGREASING | 0.00 | 3.50 | 0.00 |
| **FUEL COMBUSTION** | **63.93** | **12.51** | **17.02** |
| COGENERATION | 2.50 | 2.09 | 1.88 |
| ELECTRIC UTILITIES | 0.07 | 0.00 | 0.00 |
| FOOD AND AGRICULTURAL PROCESSING | 7.92 | 1.20 | 0.94 |
| MANUFACTURING AND INDUSTRIAL | 4.17 | 0.60 | 0.71 |
| OIL AND GAS PRODUCTION (COMBUSTION) | 0.46 | 0.01 | 0.00 |
| OTHER (FUEL COMBUSTION) | 0.08 | 0.00 | 0.00 |
| PETROLEUM REFINING (COMBUSTION) | 46.80 | 7.98 | 13.36 |
| SERVICE AND COMMERCIAL | 1.92 | 0.63 | 0.12 |
| **INDUSTRIAL PROCESSES** | **0.00** | **74.05** | **1.23** |
| CHEMICAL | 0.00 | 72.32 | 0.04 |
| MINERAL PROCESSES | 0.00 | 0.00 | 0.00 |
| OTHER (INDUSTRIAL PROCESSES) | 0.00 | 0.85 | 0.28 |
| FOOD AND AGRICULTURE | 0.00 | 0.89 | 0.00 |
| METAL PROCESSES | 0.00 | 0.00 | 0.03 |
| WOOD AND PAPER | 0.00 | 0.00 | 0.89 |
| **MISCELLANEOUS PROCESSES** | **12.54** | **130.25** | **48.19** |
| CONSTRUCTION AND DEMOLITION | 0.00 | 0.00 | 0.83 |
| COOKING | 0.00 | 2.00 | 12.26 |

| Source Categories | NOX (tpy) | ROG (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| FARMING OPERATIONS | 0.00 | 123.89 | 14.96 |
| FIRES | 0.05 | 0.18 | 0.24 |
| FUGITIVE WINDBLOWN DUST | 0.00 | 0.00 | 5.30 |
| MANAGED BURNING AND DISPOSAL | 0.98 | 1.43 | 1.85 |
| PAVED ROAD DUST | 0.00 | 0.00 | 7.91 |
| RESIDENTIAL FUEL COMBUSTION | 11.51 | 2.74 | 2.80 |
| UNPAVED ROAD DUST | 0.00 | 0.00 | 2.03 |
| **OTHER MOBILE SOURCES** | **102.31** | **46.46** | **4.77** |
| AIRCRAFT | 0.19 | 0.00 | 0.00 |
| FARM EQUIPMENT | 32.50 | 5.47 | 1.88 |
| FUEL STORAGE AND HANDLING | 0.00 | 3.04 | 0.00 |
| OFF-ROAD EQUIPMENT | 45.68 | 28.17 | 2.16 |
| OFF-ROAD EQUIPMENT (PERP) | 16.11 | 1.48 | 0.59 |
| OFF-ROAD RECREATIONAL VEHICLES | 0.06 | 3.83 | 0.01 |
| RECREATIONAL BOATS | 0.00 | 4.47 | 0.00 |
| TRAINS | 7.78 | 0.00 | 0.12 |
| **PETROLEUM PRODUCTION AND MARKETING** | **1.41** | **56.19** | **0.29** |
| OIL AND GAS PRODUCTION | 1.30 | 21.85 | 0.14 |
| PETROLEUM MARKETING | 0.11 | 11.64 | 0.15 |
| PETROLEUM REFINING | 0.00 | 22.70 | 0.00 |
| **SOLVENT EVAPORATION** | **0.00** | **160.97** | **0.00** |
| ARCHITECTURAL COATINGS AND RELATED PROCESS SOLVENTS | 0.00 | 27.65 | 0.00 |
| CONSUMER PRODUCTS | 0.00 | 56.12 | 0.00 |
| PESTICIDES/FERTILIZERS | 0.00 | 77.19 | 0.00 |
| **WASTE DISPOSAL** | **1.97** | **847.33** | **0.44** |
| LANDFILLS | 1.97 | 0.11 | 0.10 |
| OTHER (WASTE DISPOSAL) | 0.00 | 847.22 | 0.33 |
| **Grand Total** | **182.16** | **1340.16** | **71.94** |

### *Forecasting Emissions – Area Sources*

Emission forecasts are based on growth profiles that in many cases incorporate historical trends up to the base year or beyond. The growth surrogates used to forecast the emissions from these categories are presented below.

Tables 13 and 14 below summarize the total projected area source emissions for each category in the Arvin/Lamont Community for years 2026 and 2031:

***Table 13: Year 2026 Projected Area Source Emissions for Arvin-Lamont Community***

| Source Categories | NOX (tpy) | ROG (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| **CLEANING AND SURFACE COATINGS** | **0.00** | **15.22** | **1.27** |
| ADHESIVES AND SEALANTS | 0.00 | 1.16 | 0.00 |
| COATINGS AND RELATED PROCESS SOLVENTS | 0.00 | 10.03 | 1.27 |
| DEGREASING | 0.00 | 4.03 | 0.00 |
| **FUEL COMBUSTION** | **51.26** | **12.36** | **16.98** |
| COGENERATION | 2.53 | 2.11 | 1.91 |
| ELECTRIC UTILITIES | 0.07 | 0.00 | 0.00 |
| FOOD AND AGRICULTURAL PROCESSING | 5.52 | 0.98 | 0.86 |
| MANUFACTURING AND INDUSTRIAL | 4.22 | 0.61 | 0.72 |
| OIL AND GAS PRODUCTION (COMBUSTION) | 0.36 | 0.01 | 0.00 |
| OTHER (FUEL COMBUSTION) | 0.07 | 0.00 | 0.00 |
| PETROLEUM REFINING (COMBUSTION) | 36.64 | 7.98 | 13.36 |
| SERVICE AND COMMERCIAL | 1.86 | 0.66 | 0.12 |
| **INDUSTRIAL PROCESSES** | **0.00** | **75.86** | **0.95** |
| CHEMICAL | 0.00 | 73.98 | 0.04 |
| MINERAL PROCESSES | 0.00 | 0.00 | 0.00 |
| OTHER (INDUSTRIAL PROCESSES) | 0.00 | 0.90 | 0.00 |
| FOOD AND AGRICULTURE | 0.00 | 0.97 | 0.00 |
| METAL PROCESSES | 0.00 | 0.00 | 0.03 |
| WOOD AND PAPER | 0.00 | 0.00 | 0.88 |
| **MISCELLANEOUS PROCESSES** | **12.23** | **128.39** | **49.82** |
| CONSTRUCTION AND DEMOLITION | 0.00 | 0.00 | 0.86 |
| COOKING | 0.00 | 2.17 | 13.30 |
| FARMING OPERATIONS | 0.00 | 121.79 | 14.33 |
| FIRES | 0.05 | 0.19 | 0.26 |
| FUGITIVE WINDBLOWN DUST | 0.00 | 0.00 | 5.07 |
| MANAGED BURNING AND DISPOSAL | 0.95 | 1.40 | 1.81 |
| PAVED ROAD DUST | 0.00 | 0.00 | 9.31 |
| RESIDENTIAL FUEL COMBUSTION | 11.23 | 2.83 | 2.92 |
| UNPAVED ROAD DUST | 0.00 | 0.00 | 1.95 |
| **OTHER MOBILE SOURCES** | **71.63** | **40.51** | **2.98** |
| AIRCRAFT | 0.14 | 0.00 | 0.00 |
| FARM EQUIPMENT | 19.55 | 3.71 | 1.16 |
| FUEL STORAGE AND HANDLING | 0.00 | 2.56 | 0.00 |
| OFF-ROAD EQUIPMENT | 36.42 | 26.43 | 1.45 |
| OFF-ROAD EQUIPMENT (PERP) | 7.67 | 0.97 | 0.23 |
| OFF-ROAD RECREATIONAL VEHICLES | 0.07 | 3.09 | 0.02 |
| RECREATIONAL BOATS | 0.00 | 3.76 | 0.00 |
| TRAINS | 7.78 | 0.00 | 0.12 |
| **PETROLEUM PRODUCTION AND MARKETING** | **0.50** | **48.35** | **0.20** |
| OIL AND GAS PRODUCTION | 0.40 | 16.70 | 0.07 |

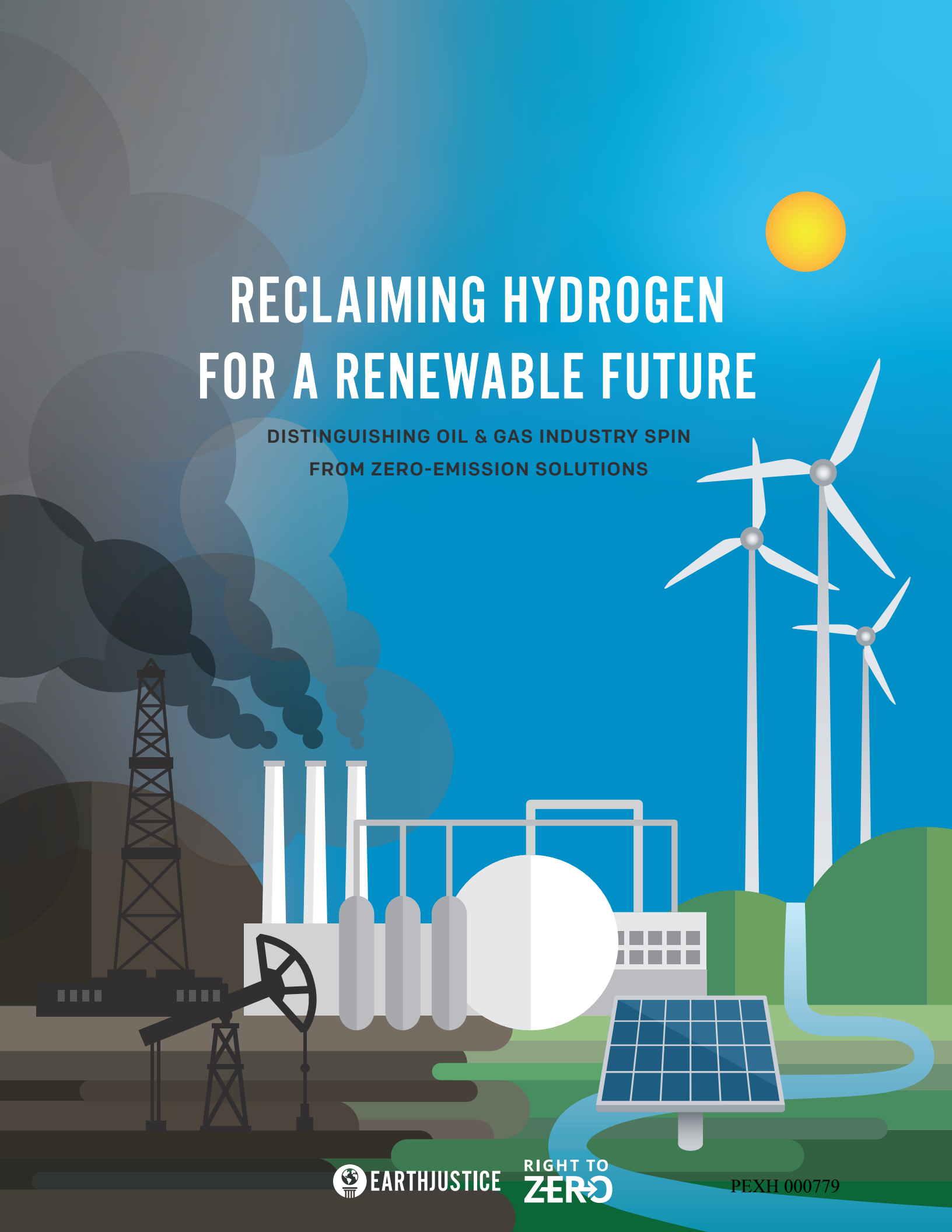
| Source Categories | NOX (tpy) | ROG (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| PETROLEUM MARKETING | 0.10 | 8.94 | 0.13 |
| PETROLEUM REFINING | 0.00 | 22.70 | 0.00 |
| **SOLVENT EVAPORATION** | **0.00** | **165.50** | **0.00** |
| ARCHITECTURAL COATINGS AND RELATED PROCESS SOLVENTS | 0.00 | 29.14 | 0.00 |
| CONSUMER PRODUCTS | 0.00 | 62.58 | 0.00 |
| PESTICIDES/FERTILIZERS | 0.00 | 73.79 | 0.00 |
| **WASTE DISPOSAL** | **1.28** | **919.13** | **0.36** |
| LANDFILLS | 1.28 | 0.09 | 0.08 |
| OTHER (WASTE DISPOSAL) | 0.00 | 919.04 | 0.28 |
| **Grand Total** | **136.89** | **1405.31** | **72.57** |

***Table 14: Year 2031 Projected Area Source Emissions for Stockton Community***

| Source Categories | NOX (tpy) | ROG (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| **CLEANING AND SURFACE COATINGS** | **0.00** | **16.40** | **1.34** |
| ADHESIVES AND SEALANTS | 0.00 | 1.16 | 0.00 |
| COATINGS AND RELATED PROCESS SOLVENTS | 0.00 | 10.74 | 1.34 |
| DEGREASING | 0.00 | 4.50 | 0.00 |
| **FUEL COMBUSTION** | **45.30** | **12.37** | **17.05** |
| COGENERATION | 2.57 | 2.15 | 1.94 |
| ELECTRIC UTILITIES | 0.07 | 0.00 | 0.00 |
| FOOD AND AGRICULTURAL PROCESSING | 4.34 | 0.92 | 0.87 |
| MANUFACTURING AND INDUSTRIAL | 4.37 | 0.64 | 0.76 |
| OIL AND GAS PRODUCTION (COMBUSTION) | 0.31 | 0.01 | 0.00 |
| OTHER (FUEL COMBUSTION) | 0.07 | 0.00 | 0.00 |
| PETROLEUM REFINING (COMBUSTION) | 31.69 | 7.98 | 13.36 |
| SERVICE AND COMMERCIAL | 1.87 | 0.68 | 0.13 |
| **INDUSTRIAL PROCESSES** | **0.00** | **82.33** | **0.97** |
| CHEMICAL | 0.00 | 80.29 | 0.04 |
| MINERAL PROCESSES | 0.00 | 0.00 | 0.00 |
| OTHER (INDUSTRIAL PROCESSES) | 0.00 | 0.96 | 0.00 |
| FOOD AND AGRICULTURE | 0.00 | 1.08 | 0.00 |
| METAL PROCESSES | 0.00 | 0.00 | 0.03 |
| WOOD AND PAPER | 0.00 | 0.00 | 0.89 |
| **MISCELLANEOUS PROCESSES** | **12.09** | **127.55** | **50.85** |
| CONSTRUCTION AND DEMOLITION | 0.00 | 0.00 | 0.91 |
| COOKING | 0.00 | 2.27 | 13.91 |

| Source Categories | NOX (tpy) | ROG (tpy) | PM2.5 (tpy) |
|---|---|---|---|
| FARMING OPERATIONS | 0.00 | 120.83 | 13.98 |
| FIRES | 0.05 | 0.20 | 0.27 |
| FUGITIVE WINDBLOWN DUST | 0.00 | 0.00 | 4.94 |
| MANAGED BURNING AND DISPOSAL | 0.93 | 1.38 | 1.79 |
| PAVED ROAD DUST | 0.00 | 0.00 | 10.16 |
| RESIDENTIAL FUEL COMBUSTION | 11.10 | 2.87 | 2.98 |
| UNPAVED ROAD DUST | 0.00 | 0.00 | 1.91 |
| **OTHER MOBILE SOURCES** | **63.69** | **39.17** | **2.45** |
| AIRCRAFT | 0.12 | 0.00 | 0.00 |
| FARM EQUIPMENT | 14.24 | 2.98 | 0.84 |
| FUEL STORAGE AND HANDLING | 0.00 | 2.48 | 0.00 |
| OFF-ROAD EQUIPMENT | 34.97 | 27.10 | 1.32 |
| OFF-ROAD EQUIPMENT (PERP) | 6.52 | 0.96 | 0.15 |
| OFF-ROAD RECREATIONAL VEHICLES | 0.07 | 2.24 | 0.02 |
| RECREATIONAL BOATS | 0.00 | 3.39 | 0.00 |
| TRAINS | 7.78 | 0.00 | 0.12 |
| **PETROLEUM PRODUCTION AND MARKETING** | **0.44** | **45.32** | **0.18** |
| OIL AND GAS PRODUCTION | 0.34 | 14.42 | 0.06 |
| PETROLEUM MARKETING | 0.09 | 8.20 | 0.12 |
| PETROLEUM REFINING | 0.00 | 22.70 | 0.00 |
| **SOLVENT EVAPORATION** | **0.00** | **169.58** | **0.00** |
| ARCHITECTURAL COATINGS AND RELATED PROCESS SOLVENTS | 0.00 | 30.47 | 0.00 |
| CONSUMER PRODUCTS | 0.00 | 67.24 | 0.00 |
| PESTICIDES/FERTILIZERS | 0.00 | 71.87 | 0.00 |
| **WASTE DISPOSAL** | **1.35** | **961.37** | **0.38** |
| LANDFILLS | 1.35 | 0.09 | 0.08 |
| OTHER (WASTE DISPOSAL) | 0.00 | 961.27 | 0.29 |
| **Grand Total** | **122.87** | **1454.10** | **73.21** |

# Exhibit CC. Sasan Saadat and Sara Gersen, Reclaiming Hydrogen for a Renewable Future: Distinguishing Oil & Gas Industry Spin from Zero-Emission Solutions (2021)



# RECLAIMING HYDROGEN FOR A RENEWABLE FUTURE

## DISTINGUISHING OIL & GAS INDUSTRY SPIN FROM ZERO-EMISSION SOLUTIONS

EARTHJUSTICE

RIGHT TO ZERO

PEXH 000779

# AUGUST 2021

Sasan Saadat, **Earthjustice's Right to Zero campaign**

Sara Gersen, **Earthjustice's Right to Zero campaign**

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# EXECUTIVE SUMMARY

The fossil fuel industry has helped generate enormous interest around hydrogen, making it difficult for policymakers to tell how much they can rely on hydrogen to meet climate goals. Too often, companies that profit from our reliance on fossil fuels invoke the vague promise of "clean," "renewable," or "green" hydrogen to derail action today. To avoid this trap, policymakers must scrutinize claims about hydrogen and think critically about where it can be a meaningful part of real climate solutions. To reclaim hydrogen for a renewable future, policymakers should explore opportunities to produce hydrogen from renewable electricity and use it to decarbonize sectors that cannot directly rely on a renewable electric grid.

First, reclaiming hydrogen for a zero-emission future requires a transition away from producing it with polluting technologies. Currently, oil and gas companies produce nearly all of the United States' annual supply of hydrogen—about 10 million metric tons—from fossil fuels through a process that pollutes neighboring communities with health-harming emissions and the atmosphere with greenhouse gases. Transforming hydrogen from a climate threat to a climate tool requires a transition to green hydrogen. **Green hydrogen is made using 100% renewable electricity to split hydrogen from water molecules**. For now, this is the only established way to produce hydrogen without emitting greenhouse gases or other health-harming pollutants. This whitepaper helps policymakers distinguish green hydrogen from hydrogen produced through polluting processes using inputs like fossil fuels and gas from factory farms. Fueling an industrial facility with green hydrogen would mitigate climate pollution, but not other pollution from its industrial processes, and so deployment of green hydrogen can never justify a buildout of facilities that would increase toxic pollution.

**It will always be more efficient to rely first on the direct use of renewable electricity wherever it is possible to do so, rather than convert that electricity into hydrogen before using it as an energy source.**

Once policymakers understand what green hydrogen is, they should consider the barriers to its widespread deployment. It will always be more efficient to rely first on the direct use of renewable electricity wherever it is possible to do so, rather than convert that electricity into hydrogen before using it as an energy source. This principle applies to vehicles, household appliances, and any other sector that has clean electric options for decarbonization. Moreover, relying on green hydrogen will require significant investments in storage and transportation infrastructure like dedicated pipelines because it behaves differently than the methane in our existing fossil gas infrastructure. Leakage in this infrastructure could undermine the benefits of green hydrogen because hydrogen is a greenhouse gas that is five times more potent than carbon dioxide. Scaling up the infrastructure to make green hydrogen widely available will take another decade—too long to delay dramatic reductions of climate pollution in the sectors that have other decarbonization options.

With these limitations in mind, policymakers can identify the sectors for which green hydrogen may nevertheless be a promising decarbonization tool, where it is worth careful exploration, and where they should instead deploy other technologies that are available today.

Our best option for deploying green hydrogen is to displace the fossil fuel-derived hydrogen already in use today. However, hydrogen is not an excuse to build or expand polluting industrial facilities. After additional study, policymakers may also find that green hydrogen is an appropriate tool for decarbonizing maritime shipping, aviation, industrial processes that require high temperatures, long-distance trucks or trains, and/or a small portion of our electricity supply. Given the limits on the supply of green hydrogen that are likely to persist for another decade, in the near-term, policymakers should reserve it for sectors that do not have other viable decarbonization options.



**The gas industry has used false promises around hydrogen to hinder commonsense climate action, such as the shift to electric appliances like the induction stove top pictured here.** *Tom Werner / Getty Images*

For the sectors that have zero-emission solutions available today, policymakers should embrace those solutions and reject any suggestion that climate action can wait for green hydrogen. For instance, the gas industry has used false promises around hydrogen to fight commonsense proposals to transition to clean, electric alternatives to burning gas in residential and commercial appliances. However, green hydrogen cannot make a meaningful dent in the climate pollution from these gas-fired appliances and the leaky pipelines that deliver gas to America's homes and businesses.

Meeting the scale and urgency of the climate crisis will require deployment of renewable resources on an unprecedented scale and a widespread transition to electric models for things like household appliances and cars—uses where electric technologies are readily available and economies of scale will further drive down costs. For instance, in the

transportation sector, battery-electric vehicles are the most promising decarbonization strategy for most on-road vehicles. Stabilizing the climate will require aggressive near-term investments in these vehicles and their fueling infrastructure, regardless of whether green hydrogen may prove to be a cost-effective tool for some heavy-duty long-haul vehicles.

**Green hydrogen provides an additional reason to deploy renewable energy resources at an unprecedented pace.** Not only are massive investments in renewable resources like wind and solar necessary to decarbonize the electric grid, but economies of scale in renewable electricity generation are key to driving down the cost of green hydrogen. Despite industry rhetoric to the contrary, green hydrogen is not an excuse to build, expand or continue operations at gas-fired power plants. Even if future innovations may make it possible to retrofit these combustion turbines to operate solely on green hydrogen, the facilities would continue to pollute the air and burden the water supply. Today's renewable energy and battery technologies can cost-effectively supply 80% of the electricity we need by 2030 and 90% by 2035. Green hydrogen is a potential tool for achieving a fully decarbonized electric grid because it can store renewable energy for long periods and convert it back into electricity with zero-emission fuel cell technologies.

As we continue to electrify everything that can feasibly plug into a clean power grid, we can strategically deploy green hydrogen to displace the fossil-derived hydrogen that industry is using today and to power sectors that are otherwise difficult to electrify. When used as a marketing tool by the fossil fuel industry, hydrogen can be used to hinder necessary climate action. But when reclaimed and deployed as a solution to decarbonize sectors we cannot otherwise electrify, green hydrogen can play an important role in a zero-emission future.

# INTRODUCTION

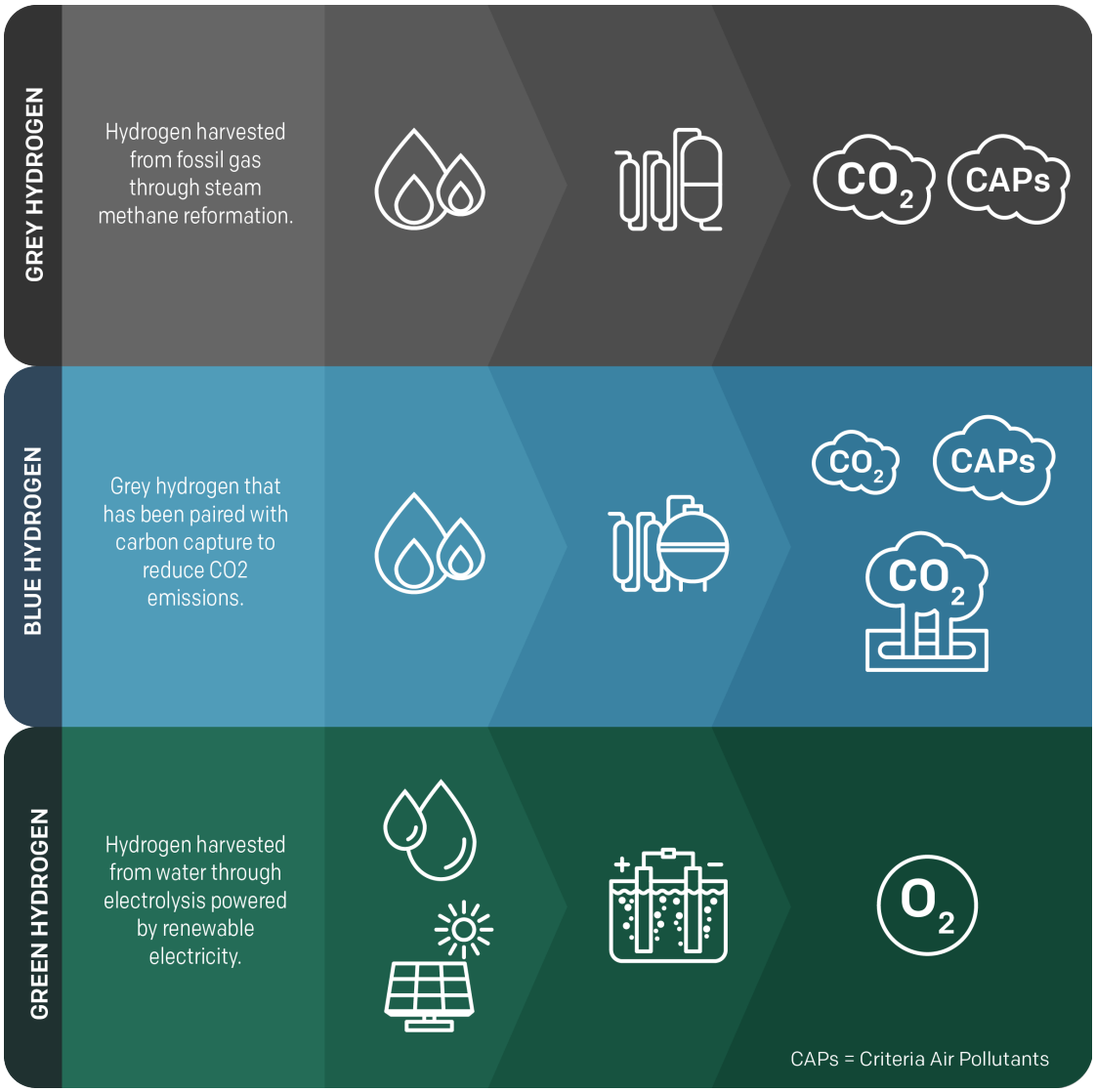
To chart a course toward a safer climate and more habitable planet, we must rapidly reduce emissions of greenhouse gases across our society. The biggest contributor to greenhouse gas emissions is the burning of fossil fuels. Consequently, the clearest path to reducing emissions is to switch from fossil fuels to renewable, zero-emission energy in our transportation, buildings, and power generation (sectors that are collectively responsible for about 75% of United States' greenhouse gas emissions).[1] This transition would make significant strides in eliminating the devastating public health impacts of pollution throughout the life cycle of fossil fuels—pollution that is most severely concentrated in Black, Brown, Indigenous, and poor communities.[2] A just transition will also require careful policy design and meaningful engagement from frontline communities. Renewable energy, energy efficiency, and electrification are zero-emission solutions that eliminate both greenhouse gases and health-harming air pollution. To meet the scale and urgency of the climate crisis will require deployment of renewable resources on an unprecedented scale—ultimately achieving 100% clean power generation—and a complete transition to efficient, electric models for things like household appliances and cars.

As we electrify everything that can feasibly plug into a clean power grid, "green hydrogen" is a promising tool for transitioning to renewable energy in sectors that lack a viable route to direct electrification. Green hydrogen is hydrogen produced by using 100% renewable electricity to split water molecules.

To understand the potential role of green hydrogen, consider the challenges of cutting climate pollution from one hard-to-electrify sector: maritime shipping. Maritime travel is difficult to decarbonize because battery-powered ocean-going vessels will not be able to handle long-haul voyages across the ocean, at least for the foreseeable future. The hope for green hydrogen is that it may store energy from clean electric resources like wind and solar in a fuel that could be used to propel large, long-haul ships. This vision is at least a decade away from reality, if it overcomes the challenges to cost-effective production and efficient on-vessel storage. Still, it offers a path to displacing the highly polluting bunker fuel currently relied on to move much of the world's goods across oceans.

**Section I describes the status quo in industrial hydrogen production.** Despite hydrogen's potential to become a climate solution in the future, today's reality is that global hydrogen production—more than 99.8 % of which is not green—is responsible for an enormous amount of climate pollution, more than the entire nation of Germany.[3] Oil and gas companies produce almost all of the United States' hydrogen supply from fossil gas, through a pollution-intensive process called steam methane reformation. Communities near oil refineries bear the brunt of this pollution because hydrogen production most often takes place at refineries, which are the main hydrogen consumers.

**Figure 1. Three Types of Hydrogen Production**




Globally, less than 1 percent of hydrogen is produced through electrolysis and less than 0.02% is green hydrogen (i.e., produced from electrolysis powered purely by renewable electricity).[4] **Using hydrogen will not break our dependence on fossil fuels unless we quit relying on fossil fuels to produce hydrogen**.

**Section II discusses the fossil fuel industry's recent public relations blitz supporting increased reliance on hydrogen.** The fossil fuel industry has created a wave of hype around investments in hydrogen, which often conflates green hydrogen with the polluting hydrogen that the industry produces from fossil gas. One of the industry's main strategies is to fund trade associations that advocate for policies that would increase hydrogen production from renewables and fossil fuels alike. Companies are also using hydrogen to greenwash new investments in fossil fuels, as they attempt to justify infrastructure projects with the vague and unsupported notion that the fossil fuel infrastructure might one day be repurposed for hydrogen. Policymakers must carefully scrutinize claims about hydrogen becoming a climate solution because the fossil fuel industry is aggressively promoting investments in hydrogen that would benefit their shareholders, but are not wise climate solutions.

**Section III discusses the definition of green hydrogen and the challenges to its widespread deployment.** To help policymakers avoid unsustainable or costly decisions, this report offers criteria to help decide where it might be appropriate to deploy green hydrogen. Widely deployed green hydrogen is still at least a decade away and will always be less efficient than directly using renewable electricity wherever feasible. Still, green hydrogen could be a good climate solution for specific applications in a sector if:

## CRITERIA FOR DEPLOYING GREEN HYDROGEN

1. There are no low-cost decarbonization strategies available;
2. There are no electric technologies being developed that could take advantage of zero-emission electricity directly;
3. The logistics and costs of infrastructure for hydrogen transportation and storage can be contained;
4. Technologies for using hydrogen fuel in the sector are or will be available; and
5. Transitioning to green hydrogen could reduce air pollution.

**Section IV discusses the potential for green hydrogen as a decarbonization tool in different sectors.** Based on the considerations presented in Section III, the highest priority and best use for green hydrogen is to displace the massive amounts of fossil-derived hydrogen that are currently being used in industrial processes. For the next few years, volumes of green hydrogen will be small and costs will be high. Policymakers need to direct this precious resource to displace existing, pollution-intensive hydrogen, rather than create new pots of hydrogen demand.

## STEAM METHANE REFORMATION

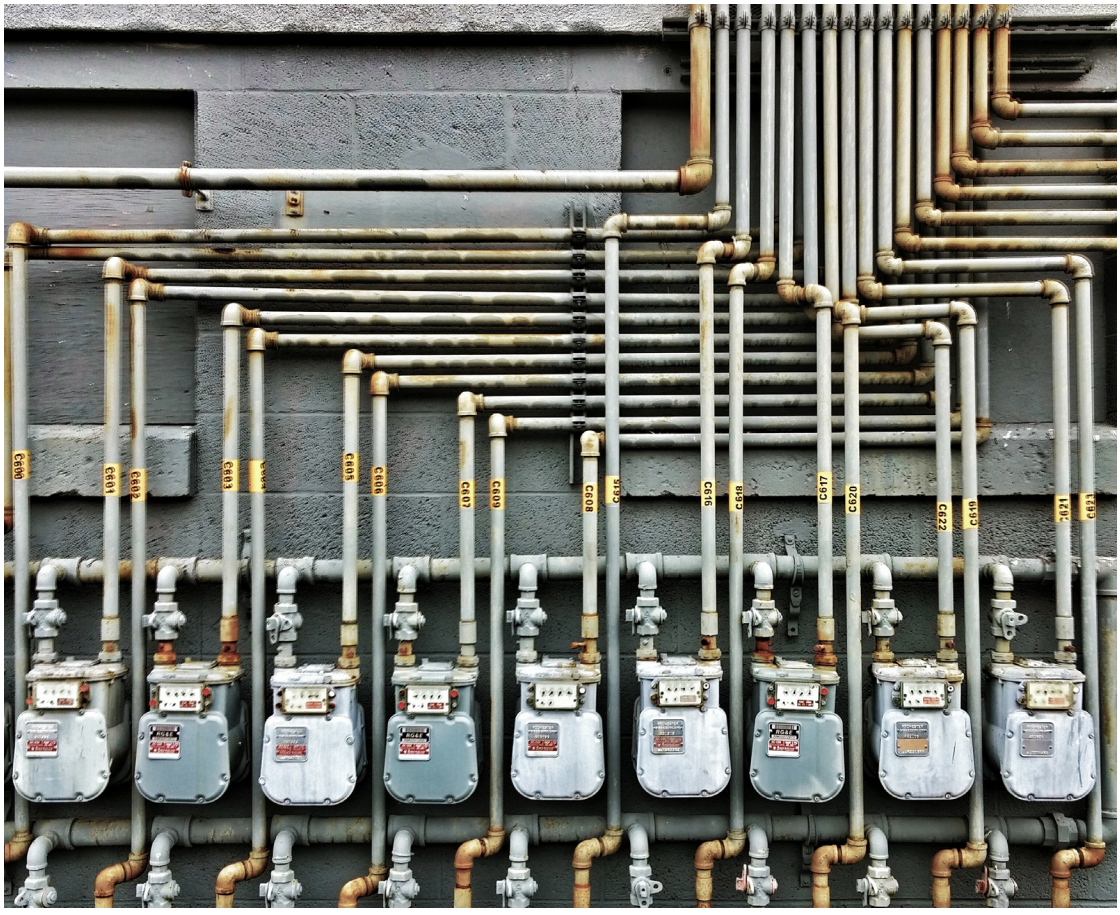
Methane is made up of 1 carbon and 4 hydrogen atoms. To obtain hydrogen, high-temperature steam (water vapor at 700-1000 °C) reacts with the methane under pressure. The reaction of methane ($CH_4$) and water vapor ($H_2O$) produces hydrogen gas ($H_2$) and carbon monoxide (CO). A second reaction (pressure swing adsorbtion) is performed with additional steam ($H_2O$) to purify the CO and $CH_4$ mixture, leaving more Hydrogen and carbon dioxide ($CO_2$).

$CH_4 + H_2O$ (steam) $\rightarrow CO + 3H_2$
$CO + H_2O$ (steam) $\rightarrow CO_2 + H_2$

In the 2030s, green hydrogen's role could expand to address hard-to-electrify sectors or provide a small portion of our electric power supply by storing surplus renewable energy. Maritime shipping, aviation, high-heat industrial processes, and long-haul trucking are all potential applications for green hydrogen that policymakers should explore with caution. **In the meantime, the declining cost of renewables and batteries is widening the range of things that can easily be electrified, potentially narrowing the applications for which hydrogen should be considered.**

There are some sectors for which hydrogen is a dead end. The chief subject of misleading industry hype is the gas distribution network. The pipeline system that delivers methane to gas-fired appliances in homes and businesses cannot carry a significant amount of hydrogen—researchers estimate that hydrogen can only comprise about 7% of its energy content before hydrogen creates safety hazards. Nonetheless, gas companies tout hydrogen as a means of continuing their business model, while fighting against a climate solution that is available today: a full transition to electric appliances.

The very real risk is that these fossil fuel industry initiatives use the idea of green hydrogen to drive climate investments toward fossil fuel assets while siphoning them away from established, zero-emission solutions. The most urgent, near-term priority for climate action is accelerating deployment of the solutions that are already available and managing the transition from the fossil fuel economy. In addition to these aggressive near-term actions, policymakers can explore the potential for green hydrogen to decarbonize hard-to-electrify sectors.



**These gas distribution lines cannot be used to deliver pure hydrogen. Injecting appreciable volumes of hydrogen in gas lines to burn in gas appliances poses health and safety risks.** *Kevin Lucas, EyeEm / Getty Images*

# I TODAY, HYDROGEN PRODUCTION RELIES ON FOSSIL FUELS AND THREATENS OUR CLIMATE AND PUBLIC HEALTH

The recent hype around hydrogen can mask the fact that the fossil fuel industry already produces hydrogen on a massive scale, with devastating consequences for the climate and communities. Gas companies and oil refineries are responsible for producing nearly all of the United States' annual supply of hydrogen—about 10 million metric tons[5]—through an energy-intensive industrial process called steam methane reformation (SMR) of fossil gas.[6,7] Coal gasification is also a significant source of hydrogen production in other parts of the world, accounting for 2% of global coal demand.[8] Globally, hydrogen production's toll on the climate is so great that hydrogen production is responsible for more greenhouse gas emissions than the entire country of Germany.[9]

In addition to emitting greenhouse gases, SMR emits pollution that harms public health in neighboring communities, including nitrogen oxides, fine particulate matter, carbon monoxide, and volatile organic compounds.[10] While SMR plants contribute to warming the climate globally, their local impacts are concentrated in the same communities on the frontlines of oil refineries. Oil refining company Phillips 66 for example, recently entered an agreement with industrial gas company Linde, to **build what will be the largest hydrogen production unit in the United States**.[11] The SMR project is being constructed in St. James Parish, Louisiana[12]—a predominately African-American community in the heart of a region of the U.S. Gulf Coast known as "Cancer Alley," so-named because the concentration of petrochemical plants and refineries cause high rates of cancer in local residents.[13]

The fossil fuel industry is not just the primary producer of hydrogen—it is also the primary consumer of hydrogen. Roughly 60% of domestic hydrogen demand comes from crude oil refineries,[14] where it is used to lower the sulfur content of diesel.[15] Demand for hydrogen from refineries continues to rise alongside

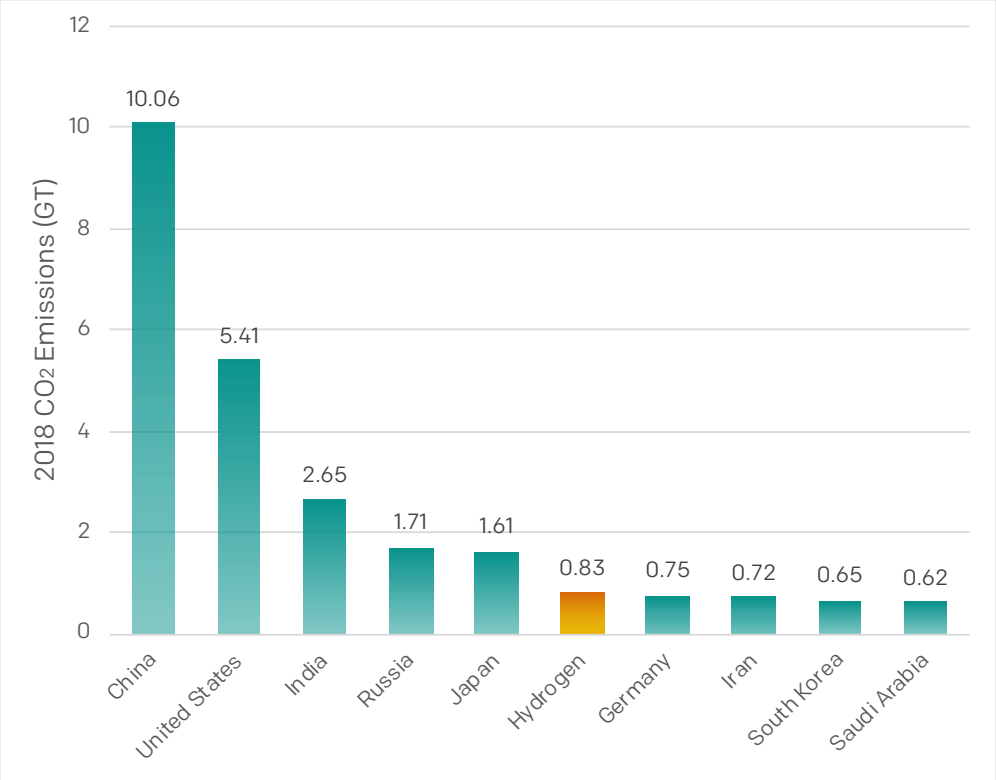



**Figure 2. Top 10 Carbon Dioxide Emitters - 2018**[21]

increasing global demand for diesel fuel. Global hydrogen demand has grown 28% over the last decade,[16] which means that pollution from producing hydrogen from fossil fuels is also increasing.[17] After the petroleum industry, the second largest consumer of hydrogen (about 30%) is industrial agribusiness, which uses hydrogen as a feedstock for chemical fertilizers.[18] The remainder (~10%) is used for other chemical and industrial processes like methanol production.[19]

The fossil fuel industry has multiple incentives for promoting hydrogen. First, the industry's vision for hydrogen calls for continued reliance on fossil gas to produce hydrogen, expanding existing revenue streams.[20] In contrast, a transition to a zero-emission economy means rejecting hydrogen from fossil fuels and *only* using green hydrogen, which is derived from 100% renewable electricity. Second, industry sometimes uses rhetoric about green hydrogen to justify new infrastructure for fossil gas. Gas utility companies boost their profits when they build more pipelines to deliver fossil gas to homes and businesses, with the monopolies' captive customers footing the bill. Some gas companies are fighting to expand their fossil gas infrastructure by spreading misleading claims about the potential for hydrogen to decarbonize their gas. Similarly, companies that profit from building gas-fired power plants are beginning to rely on the promise that they might one day retrofit these facilities to burn green hydrogen to justify investments in new gas-fired electricity generators.



**The bulk of hydrogen demand in the United States today is for use in crude oil refineries. The fossil fuel industry is the country's primary producer and consumer of hydrogen.** *Thomas Northcut / Getty Images*

## II THE FOSSIL FUEL INDUSTRY IS CAMPAIGNING TO INCREASE RELIANCE ON HYDROGEN FROM FOSSIL FUELS

Policymakers must carefully scrutinize claims about hydrogen's role in reducing climate pollution because much of the hype around hydrogen comes from the fossil fuel industry, whose foremost interest in protecting shareholder profits may not align with sensible climate strategies. As public demand for climate action continues to rise, hydrogen has taken on a central role in the oil and gas sector's long-term planning.[22] In March 2021, several oil majors, gas companies, and fossil fuel-intensive utilities launched the "Clean Hydrogen Future Coalition," which urged the Biden administration to increase policy support for a wide range of hydrogen production methods and uses.[23] Oil and gas companies have joined with other industries —primarily chemical and car companies—to form at least six trade associations to advocate for more hydrogen production in the United States.[24] As a recent article in *Nature Climate Change* observed, "the gas industry is turning to hydrogen for a new lease of life."[25]

U.S. fossil fuel companies are following a playbook that oil and gas companies have already played in Europe and Australia.[26] In the United Kingdom, a group called "the Hydrogen Taskforce," backed by BP, Shell, and a slew of gas companies, launched to advance the mission of securing hydrogen's role in the energy transition through increasing government investment. The Taskforce's focus is on increasing support for hydrogen injection into the gas grid, with goals such as achieving 100% hydrogen for home heating[27] (a goal the UK's climate chief properly called "unwieldy and impractical").[28] In the European Union, a report by watchdogs revealed that the hydrogen lobby there—mainly comprised of the gas industry—spent nearly 60 million euros successfully convincing the European Commission to pursue a "Hydrogen Backbone." This vision calls for blending small amounts of hydrogen in the existing gas system with the aspiration of eventually expanding and repurposing that system.[29] The report also highlights how a major global lobbying group, the Hydrogen Council, was launched in 2017 by FTI Consulting, a public relations firm exposed for setting up fake "grassroots groups" in the United States to oppose climate action.[30] The Australia Hydrogen Council, which similarly draws most of its members from the gas industry, as well as the oil and auto industries, is focused on advancing a vision of hydrogen-powered transportation, and calls for "incentives or government policies created to drive scalability [to] initially be hydrogen technology agnostic."[31] In California, a coalition of oil, gas, hydrogen, and auto companies wrote to Governor Gavin Newsom asking him to invest half of the $1 billion dedicated to zero-emission transportation toward "hydrogen fuel infrastructure to serve the light-duty, transit and heavy-duty vehicle markets."[32] Similarly, the Clean Hydrogen Future Coalition, which includes large gas trade associations and companies, as well as oil majors BP and Chevron, sent a recent letter to President Biden calling for additional funding and tax incentives for "clean" hydrogen "from a variety of energy resources" for the power and transportation sectors.[33]

**There are common themes that emerge across these efforts: the largest backers of hydrogen efforts are oil and gas companies; their marketing materials lead with the benefits of green hydrogen, but explicitly advocate for "all-of-the-above" hydrogen production, which is currently dominated by fossil fuel-derived hydrogen; and they primarily focus on the benefits of using hydrogen for injection in the gas grid or as a vehicle transportation fuel (where the transition to direct electrification is already underway).**

## III HYDROGEN CAN BECOME A DECARBONIZATION TOOL IN THE FUTURE IF POLICYMAKERS SEPARATE THE PROMISING OPPORTUNITIES FROM FOSSIL FUEL INDUSTRY HYPE

This section provides information to help policymakers understand the potential for using green hydrogen to reduce emissions and to identify instances where industries are making misleading claims about hydrogen to fight climate solutions that are available and cost-effective today. First, we explain what it means for hydrogen to be "green," which is a critical concept to understand in light of the many industry claims of "clean," "renewable," and "green" hydrogen that include highly polluting production pathways. Next, we explain the challenges to deploying green hydrogen. Policymakers should consider these limitations to determine where green hydrogen could be a useful decarbonization strategy.

### 1. FOR NOW, THE ONLY ESTABLISHED WAY TO MAKE HYDROGEN WITHOUT GREENHOUSE GAS EMISSIONS IS BY USING RENEWABLE ENERGY TO FUEL ELECTROLYSIS.

The first step in understanding whether a hydrogen project is a practical climate solution is to ask how the hydrogen is made. As discussed above, the predominant method for producing hydrogen today is a highly polluting process called steam methane reformation of fossil gas. Creating hydrogen that is suitable for a sustainable and equitable energy transition requires a total transformation in how it is produced. Today, the only established method of producing hydrogen without emitting greenhouse gases or other pollution is using renewable electricity to power electrolysis: a process that splits hydrogen from water molecules. We use the more specific term "green hydrogen" in this report to refer to this kind of hydrogen, consistent with the International Energy Agency's definition of "green hydrogen": hydrogen produced "using electricity generated from renewable energy sources."[34] While other nascent production pathways are being explored for producing hydrogen without pollution,[35] it would be premature to include other technologies in a definition of green hydrogen before they prove their ability to produce hydrogen without emissions.

To rely on electrolytic hydrogen as a climate strategy, it is essential to use 100% renewable energy to produce the hydrogen. Because electrolysis is so energy-intensive, hydrogen made with grid-average electricity is *even more carbon intensive than hydrogen made from SMR of fossil gas*. This is true even in California, which has a cleaner electric grid than most of the country.[36]

To deliver meaningful environmental benefits, green hydrogen production must be paired with the build-out of new renewable resources and/or use surplus renewable energy. If hydrogen producers were to buy power from existing hydropower, solar, or wind facilities, the customers who have historically purchased that renewable energy are liable to shift to grid-average electricity or contract with a fossil fueled generator. When power plants burn more fossil fuels to serve these customers, it defeats the purported environmental benefits of the "green" hydrogen producers using renewable energy. This phenomenon is known as "resource shuffling."

**To deliver meaningful environmental benefits, green hydrogen production must be paired with the build-out of new renewable resources and/or use surplus renewable energy.**

Policymakers should exercise caution with other forms of hydrogen that industry touts as "clean," "renewable," or even "green." For instance, the California Air Resources Board allows California hydrogen producers to call hydrogen derived from fossil fuels "renewable" when the companies match their fossil gas with the "environmental attributes" of biomethane from landfills in Mississippi and dairies in Indiana.[37] These companies market their hydrogen as "renewable" even though it is made from fossil gas, using the polluting steam methane process we describe above. Policies will not

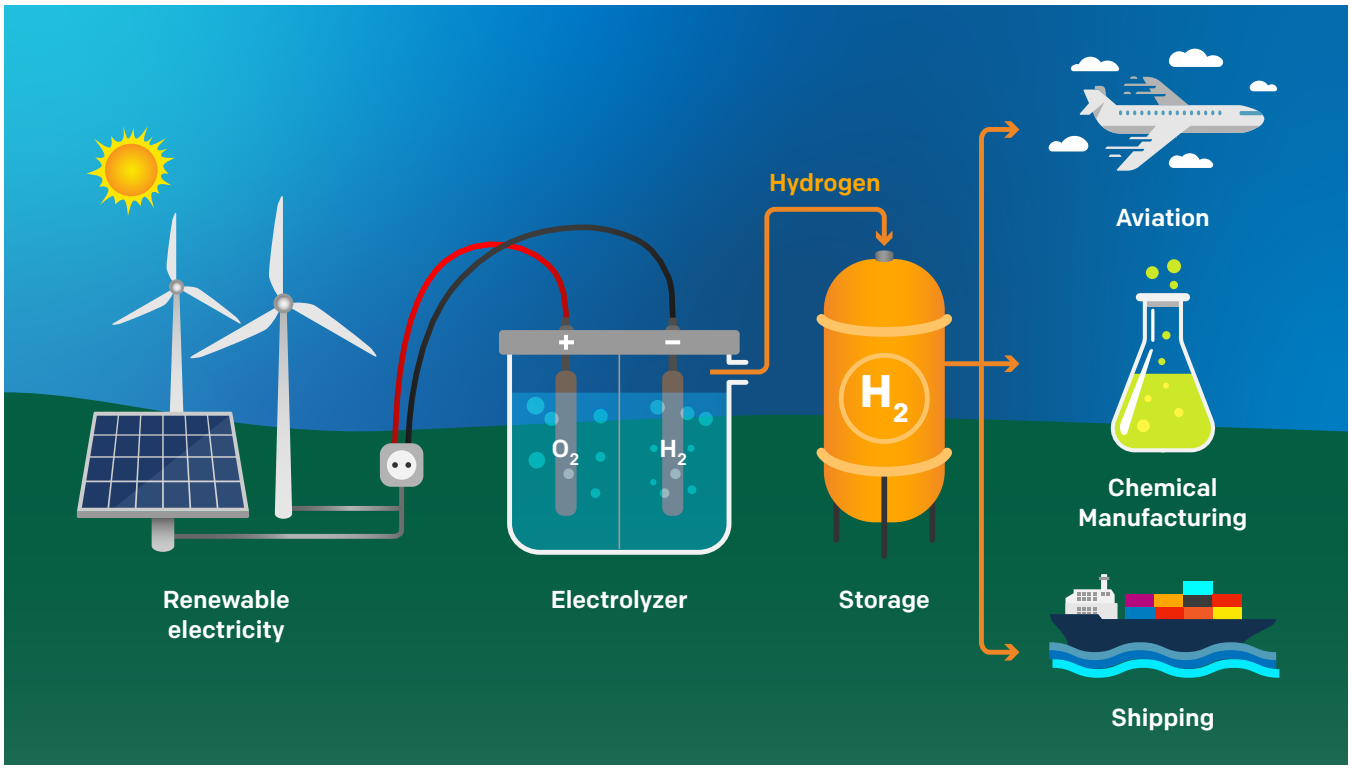



**Figure 3. Green hydrogen production and use**

catalyze the deployment of innovative technologies if their definition of "clean," "renewable," or "green" hydrogen includes the industry's business-as-usual practices paired with biomethane credits.[38]

The hydrogen industry's preferred definition of "green" hydrogen includes any hydrogen made from biomethane or biomass,[39] regardless of its climate and public health harms. For instance, this definition of "green hydrogen" would include hydrogen made from crops grown for the specific purpose of becoming an energy source. Although biomass conversion is sometimes touted as an opportunity to harness materials that would otherwise go to waste, the economic reality is that the cost-effective and logistically manageable sources of biomass are not dispersed waste streams, but energy crops. Data on the climate impacts of the U.S. EPA's Renewable Fuel Standard shows why it is essential to exclude purpose-grown energy crops as a feedstock for hydrogen. The Renewable Fuel Standard provides an incentive to increase biofuel production even though the EPA's review showed the program had led to

## EUROPEANS LEADING THE WAY ON DEPLOYING THE TECHNOLOGY TO PRODUCE GREEN HYDROGEN

In 2020, the European Commission set a target to deploy 6 GW of renewable hydrogen electrolyzers by 2024 and 40 GW by 2030.* Meeting this goal will require a massive scale up of manufacturing capacity, which the European Commission predicts could cut the costs of electrolyzers in half by 2030. Wider deployment of electrolyzers can reduce the cost of production by both allowing manufacturers to achieve economies of scale and by spurring competition between suppliers. The United States should also develop a strategy for scaling up its electrolyzer manufacturing capacity or risk being left behind.

*Neil Ford, *Europe must double green hydrogen projects to hit target* (Aug. 26, 2020), https://www.reutersevents.com/renewables/wind/europe-must-double-green-hydrogen-projects-hit-target.

the conversion of up to 8 million acres of land—nullifying and overwhelming any climate benefit the program might have had.[40]

Timber is another example of a biomass feedstock that could contribute significant greenhouse gas emissions. Policymakers must not assume that biomass from forests is a carbon-neutral source of energy, especially when there is no guarantee that logged forests will have a chance to regrow. Even when trees can regrow, it will take many decades or more than a century to recapture the carbon that enters the atmosphere when forests are logged for energy.[41]

In addition to the unproven climate benefits of biomethane- and biomass-based hydrogen, the public health and environmental harms of many biogenic feedstocks make it misleading to call this hydrogen "green." As the Federal Trade Commission has explained, consumers can interpret claims that a product has a general environmental benefit to mean that the product has no negative environmental impact.[42] Consumers' expectations for the environmental integrity of a "green" product are directly at odds with the production methods for many biogenic feedstocks, such as biomethane from cow manure lagoons. Policies that create a market for biomethane inadvertently increase pollution from industrial agriculture facilities, whose air and water pollution cause significant harm to neighboring communities that are disproportionately low-income and communities of color.[43]

Producing hydrogen from fossil fuels with carbon capture to reduce emissions (what is often referred to as "blue hydrogen") is also not compatible with a zero-emission future. Even after an industrial facility installs expensive carbon capture technologies, it will continue polluting because that equipment is expected to capture 85% to 95% of a facility's climate pollution at best.[44] The process of capturing, compressing, transporting, and storing carbon is energy intensive.[45] With a power plant, for example, carbon capture can consume 30-50% of the plant's energy output.[46] Even if it were powered by renewable energy, the environmental benefit of this added energy and cost can be undermined by leakage of stored carbon.[47] Capturing carbon also does not reduce emissions of most health-harming air pollutants, such as particulate matter and nitrogen oxide, and some researchers estimate that it will lead to lifecycle *increases* of these pollutants in line with the additional fuel needed as a result of efficiency losses and increased energy use.[48]

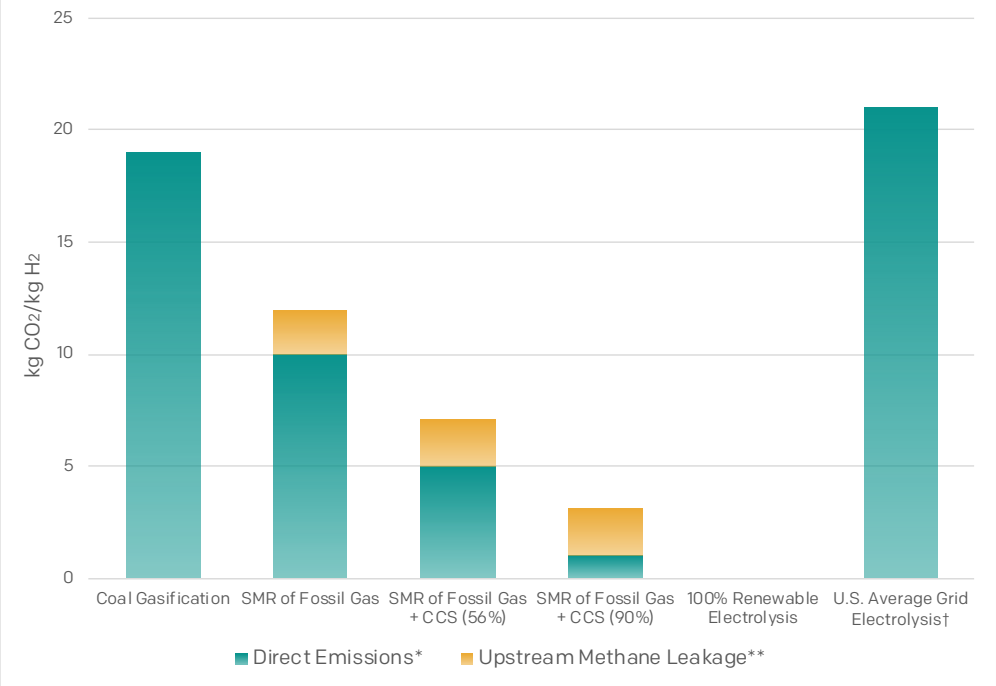



**Figure 4: Carbon Intensities of Hydrogen Production**

*Source: Bartlett and Krupnick 2020; IEA 2019

**Source: NRDC 2021

† 2017 Data, does not include upstream emissions

Moreover, carbon capture does not address the significant upstream emissions from extracting and then transporting gas across a leaky pipeline network. In the past few years, a growing number of studies have revised upward the scale of unaccounted-for leaks of methane from gas production, processing, transmission, and storage.[49] **Based on an analysis by the Natural Resources Defense Council, accounting for current upstream leakage at average rates reported in the United States would add another 2.1 kg $CO_2$/kg$H_2$ to the carbon intensity of blue hydrogen—roughly double the onsite emissions for SMR with 90% carbon capture.**[50] Even the vice president of Norwegian oil company Equinor (which is aiming to be a global leader in blue hydrogen production) acknowledged that 100% carbon capture from methane reforming is not physically possible, and admits that upstream emissions risk "killing the concept of blue hydrogen."[51]

**Carbon capture does not address the significant upstream emissions from extracting and transporting fossil gas.**

A recent United Nations report warns that the world must immediately slash methane emissions to stall near-term warming and avoid crossing irreversibly damaging climatic tipping points while we pursue rapid decarbonization. Extending and expanding reliance on methane-leaking infrastructure ignores this message.[52] Capturing carbon from fossil-fueled hydrogen production leaves these significant emissions unabated, yet comes at substantial added cost—so far, the cost of captured carbon has only been economically feasible when the carbon is used for enhanced oil recovery, which instigates further fossil fuel production and the related emissions.[53] Consequently, industry analysts and environmental groups alike warn that this strategy is likely an unwise and distracting investment.[54]

## 2. LIMITATIONS OF GREEN HYDROGEN

Green hydrogen cannot deliver near-term emissions reductions at scale because of several constraints: the significant amount of renewable energy that is lost through conversion into green hydrogen, high costs, difficulty of storage and transport, and environmental challenges such as water demand from its production. In sectors where industry might retrofit equipment that burns fossil gas to burn hydrogen, there is the additional risk that a transition to green hydrogen could increase air pollution. These constraints limit both the supply of green hydrogen and our ability to use it. Moreover, because dramatic reductions in greenhouse gas emissions must begin this decade to avert climate catastrophe, we must immediately decarbonize sectors that have solutions available today and cannot wait for the widespread availability of green hydrogen.

Therefore, proposals to use green hydrogen must be vetted on a case-by-case basis to assess whether and how they manage these constraints, and whether doing so is more cost-effective than directly using renewable electricity. Because of its scarcity, competition for green hydrogen among sectors could drive up the cost. Conversely, limiting green hydrogen demand to only essential sectors under scenarios with high renewable penetration could allow its use at negligible extra cost.[55] In the short term, the only plausible economical option will be using renewable-driven electrolysis systems for niche applications in hard-to-abate sectors where infrastructure buildouts can be contained.[56]

### Energy inefficiency

Using renewable electricity to power electrolysis results in substantial energy losses—anywhere between 20 and 40% of the energy is lost.[57] **Because of this inherent inefficiency, green hydrogen will always be a considerably more expensive fuel than renewable electricity**.[58] Not only is energy lost in the process of making green hydrogen, but equipment that uses green hydrogen is often less efficient than its competitors. A comparison of space heating technologies in buildings provides a good example of the efficiency advantages of using renewable energy directly as electricity instead of converting it to hydrogen. Hydrogen-based, low-temperature heating systems consume 500 to 600% more renewable energy than heat pumps.[59] Heat pumps can use renewable electricity on the power grid directly and efficiently. Analysts describe heat pumps

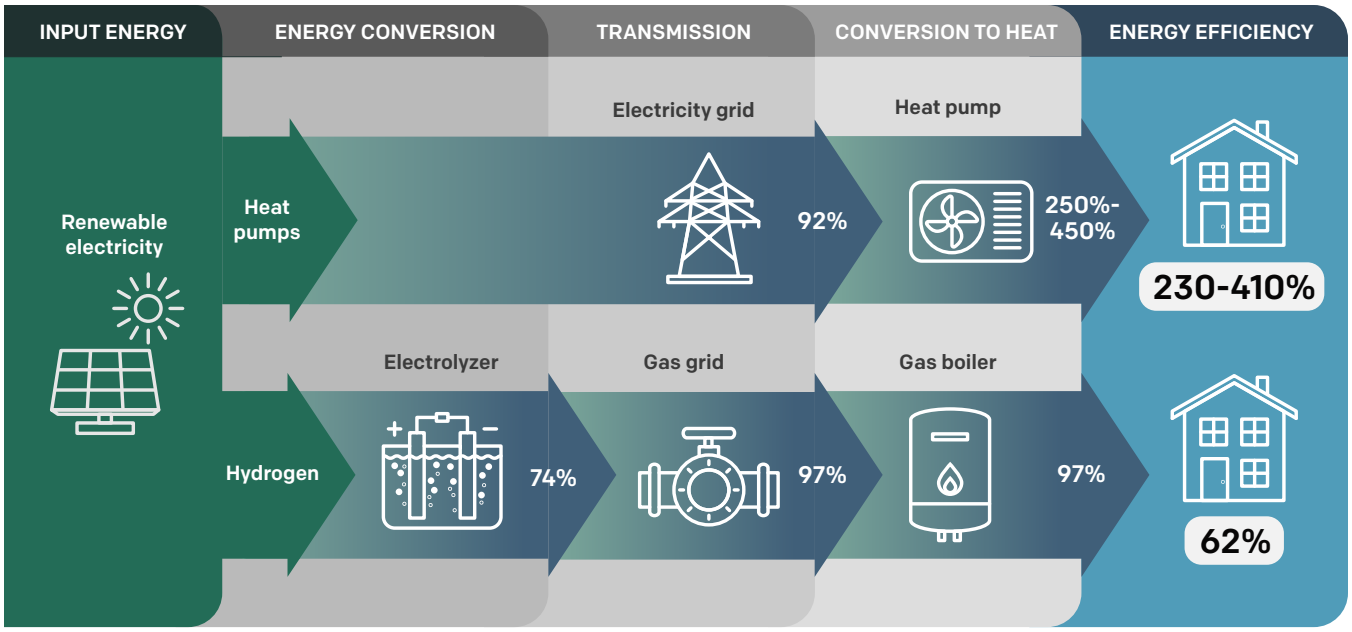



**Figure 5: Comparison of efficiencies for hydrogen and heat pumps in homes**

Data source: Ed Reed, *Hybrid hydrogen heating hopes*, Cornwall Insight Ireland (Nov. 29, 2018), https://www.cornwall-insight.com/uploads/CoTW%20Hydrogen_MH.pdf.

as having efficiencies greater than 100% because they transfer ambient heat, rather than combusting fuel to create it. Ultimately, heat pumps deliver warm air and hot water 3 to 5 times more efficiently than conventional furnaces and water heaters. As a result of their superior efficiency, heat pumps are cheaper to operate than equipment that burns fossil gas or equipment that burns green hydrogen, and even provide upfront capital cost *savings* when replacing the combination of a gas furnace and air conditioner (since heat pumps can provide both functions).[60]

Because electrolysis is so energy intensive, achieving substantial volumes of green hydrogen for any major economic sector would require enormous amounts of renewable electricity. Just deploying enough clean energy to eliminate emissions from the electricity sector by 2035 will be a titanic effort, requiring a six-fold increase over historic rates of renewable energy deployment, even if demand for electricity were static.[61] Transitioning to electric vehicles and ditching gas appliances for efficient electric technologies will dramatically increase demand for electricity and the need for new renewable resources.[62] Meeting the global demand for green hydrogen that one industry group predicts in 2050 could require the build out of solar resources that cover more than 81,250 square miles.[63] This is a land area larger than the state of Minnesota. Using green hydrogen in segments that can use direct electricity would exacerbate the challenge of deploying sufficient renewable resources by wasting renewable capacity on energy-intensive electrolysis.[64]

## Costs

Currently, conventional fossil hydrogen costs between $1.25/kilogram and $2/kilogram in the United States,[65] while green hydrogen costs between $2.50/kilogram and $4.50/kilogram.[66] Three sets of analysts — BloombergNEF, Wood Mackenzie, and McKinsey — have recently found that green hydrogen could become cost-competitive by 2030 as economies of scale drive down the cost of electrolyzers and the price of wind and solar power continues to fall.[67] The Biden administration has announced a goal of reducing the cost of green hydrogen by 80% by 2030, indicating that federal policy might help achieve price reductions even greater than what analysts have predicted by the end of the decade.[68] The biggest influence on the cost of renewable hydrogen is the cost of the clean electricity that powers its production. Low-cost green

hydrogen requires abundant, low-cost, renewable energy.[69] Increasing total deployment of renewable energy is therefore a precondition for economically producing appreciable amounts of green hydrogen.

It is important for policymakers to consider long-term cost forecasts for green hydrogen when considering permits for new gas-fired facilities if developers claim the new fossil fueled infrastructure could be retrofitted to run on green hydrogen. For example, a company that recently proposed a new gas plant in Newburgh, NY estimated that hydrogen in 2040 will cost $45/MMBtu in nominal dollars.[70] In contrast, the most recent Energy Information Administration 2020 Annual Energy Outlook projects natural gas to cost well below $4/MMBtu in 2040 (in 2019$) in its Reference Case.

**To have hydrogen replace the energy supply of fossil gas in the global economy would require building 3 to 4 times more storage and pipeline infrastructure.**

Fuel costs would be even greater for blends of green hydrogen and zero-carbon methane, as the production of "synthetic methane" involves first making green hydrogen and then using the hydrogen as an input into another chemical process. Yet, some industry members and policymakers have contemplated using blends of green hydrogen and synthetic methane in residential and commercial appliances, which were designed to burn methane and cannot safely burn pure hydrogen.[71] A report prepared for the California Energy Commission finds that "[e]ven under optimistic cost assumptions, the blended cost of hydrogen and synthetic natural gas is 8 to 17 times more expensive than the expected price trajectory of natural gas."[72] The high costs of these gases make it difficult for gas-burning appliances to compete against electric options in a zero-carbon future. The inefficiency of converting clean electricity into hydrogen (let alone synthetic methane) before using its energy will always make it more costly than plugging directly into the electric grid.

### Pollution from combustion

Burning hydrogen creates health-harming pollution. Proponents of hydrogen will often note that hydrogen fuel cells only emit water vapor, but many potential applications for hydrogen involve combustion rather than fuel cells. Hydrogen combustion's most significant public health threat is oxides of nitrogen (NOx), a pollutant that damages heart and respiratory function, impairs lung growth in children, and leads to higher rates of emergency room visits and even premature death.[73] NOx is a precursor to both ambient ozone and fine particulate matter pollution,[74] and also contributes to climate change.[75] One group of researchers predicted that **burning pure hydrogen would emit more than six times as much NOx as burning methane**, the main component in fossil gas.[76] NOx emissions could be reduced through advances in pollution control technology or by lowering flame temperatures, but this requires either lower volumes of hydrogen in the combustor (and consequently, increased reliance on fossil fuels) or de-rating the engine which results in efficiency losses and power decreases.[77] Industry should not be allowed to increase hydrogen combustion without first demonstrating control technologies that will avoid increases in NOx emissions. In 2018, air pollution from fossil fuel combustion was linked to roughly 355,000 premature deaths in the United States—pollution that African Americans were exposed to at a rate 1.54 times that of the overall population.[78] As long as combustion continues, proposals to reduce greenhouse gases by displacing some or all of the fossil fuels with hydrogen will not alleviate the uneven burdens of air pollution, and may even worsen them.

### Safe transport and storage

Today, the majority (around 90%) of hydrogen in the United States is produced at or adjacent to where it is used (either onsite by petroleum refineries that use it themselves, or by nearby gas companies that deliver it by pipeline).[79] Transporting hydrogen is expensive due to its low energy density, which means that large amounts of space are required to hold a relatively modest amount of hydrogen energy. By way of comparison, to have hydrogen replace the energy supply of fossil gas in the global economy would require building 3 to 4 times more storage and pipeline infrastructure.[80]

Safely transporting, storing, and handling hydrogen can add significant costs. For instance, it only costs a few dollars per kilogram to produce hydrogen from fossil gas, which is how most hydrogen is produced today in California and across the United States. Yet the average retail price of hydrogen at fueling stations in California is about $16.50 per kilogram—the equivalent of about $6.40 per gallon of gasoline.[81]

Precautions against leaks are also necessary at each stage of handling hydrogen. Containing hydrogen is more challenging than containing other gases because hydrogen is the smallest and lightest molecule in the universe; 50,000 molecules of hydrogen gas can fit in the width of a human hair.[82] It is also extremely flammable, making it susceptible to combust even in small concentrations.[83] Deliberate steps are necessary to detect leaks because hydrogen is a colorless and odorless gas.[84] Leakage could diminish the climate benefits of a transition to green hydrogen because hydrogen itself is a greenhouse gas that is more than five times more potent than $CO_2$.[85]

The three main ways of transporting hydrogen are by pipelines, trucks or rail, and ships, each of which would require massive investments in new infrastructure to transport hydrogen at scale:

(1) **Pipelines:** Pipelines are the most cost-effective means of transport. Hydrogen pipelines today are very limited; there are only about 1,600 miles of dedicated hydrogen pipelines in the United States—mostly clustered in Southern California and along the Gulf Coast in Texas and Louisiana near refineries and chemical plants. Building a hydrogen pipeline can cost up to 68% more per mile than a conventional fossil gas pipeline.[86] **It is important not to confuse hydrogen pipelines with the United States' vast network of gas pipelines that were designed to deliver methane because these fossil gas pipelines cannot carry meaningful volumes of hydrogen. Hydrogen's size and energy density make it incompatible with generic pipeline materials and compressor designs**.[87] Hydrogen can cause "embrittlement" in pipes and its higher flammability and leakage rates create safety risks.[88] Conventional gas pipelines do not have systems for detecting leaks of hydrogen.[89] Thus, the lowest cost manner of transporting pure hydrogen would require massive investments in dedicated pipeline networks.

(2) **Trucks and rail:** Hydrogen can also be transported in high-pressure tube trailers on trucks or rail cars. Compression in tube trailers is expensive, however, and is only suitable for small volumes over short distances of 200 miles or less.[90] Unless the trucks used to

## CAN WE RETROFIT EXISTING PIPELINES TO CARRY PURE HYDROGEN?

The first question to ask if the fossil fuel industry claims it can use existing gas infrastructure to deliver hydrogen is whether they are talking about pipelines that deliver gas to homes and commercial businesses. These "distribution" pipelines *cannot* be retrofitted to deliver pure hydrogen. The gas-burning appliances in homes and commercial buildings cannot burn hydrogen without an unacceptable risk of explosion. For insights into industry arguments for blending small amounts of hydrogen into distribution pipelines, see Section IV.

In contrast, the "transmission" pipelines that carry fossil gas from production centers to storage facilities and industrial users could conceivably be retrofitted to carry pure hydrogen. This retrofit would require significant costs, including replacing all of the pipeline's compressors.

transport the hydrogen are themselves zero-emission, then this comes with significant air pollution and greenhouse gas impacts of diesel combustion.

(3) **Ships:** For longer, intercontinental transport, hydrogen could be liquefied and transported by ship. Ships could transport relatively large volumes of liquid hydrogen, but liquefaction is expensive, and requires energy-intensive (and costly) chilling of hydrogen (to -252°C). Alternatively, ships can carry ammonia (they already do) as an energy carrier (ammonia is $NH_3$—meaning it carries three hydrogen molecules for each molecule of nitrogen). But if hydrogen is ultimately the desired commodity at its destination, this requires costly and energy-intensive re-conversion at the point of use.

The low energy density of hydrogen presents similar challenges for hydrogen's storage. Kept in a gaseous state, hydrogen storage requires large amounts of space. The cheapest solution is geologic salt caverns, which could store weeks' or months' worth of hydrogen, but these are geographically limited.[91] Pressurized containers could in theory be built anywhere, but their footprint and cost would limit them to small (days' worth) volumes.[92] To shrink hydrogen's footprint, it can be cooled and compressed to a liquid state, or converted to ammonia, but these present the same temperature and energy conversion loss challenges as shipping, mentioned above.[93] All storage options present risks, which planners should evaluate on a case-by-case basis.[94]

### Water use

Electrolysis uses freshwater as a feedstock and is thus a significant source of freshwater demand. Producing one kilogram of green hydrogen requires between 9 and 11 liters of water as a feedstock.[95] Because additional water is also required for system cooling, total water demand can be between 15 and 20 liters of water for each kilogram of green hydrogen.[96] On a global basis, the water demand for electrolysis is far less than the water requirements for extraction and processing of fossil fuels. Still, climate change will constrain global freshwater resources in significant ways—e.g., by increasing evaporation and droughts, altering precipitation patterns, melting freshwater stored in glaciers, and contaminating aquifers with saltwater from rising sea levels.[97] These impacts will mean water-stress will both expand and intensify. Regions with the potential to produce low-cost, abundant green hydrogen may intersect with areas of water-stress, presenting localized resource challenges. For example, many of the most-often discussed "solar-hydrogen superpowers" are in regions with high insolation like North Africa, the Middle East, and the U.S. Southwest—all regions with extreme drought risk.[98] Some researchers are exploring ways to use low-grade and saline water for electrolysis, which could open more opportunities for green hydrogen production in regions facing water scarcity.[99]

### Time

Today, less than 1 percent of hydrogen is produced through electrolysis and less than 0.02% is entirely produced from renewable electricity (i.e., green hydrogen).[100] **Dramatic reductions in climate pollution cannot wait until the 2030s, when we expect to see significant cost declines and increased availability for green hydrogen**. Maintaining a reasonable chance of limiting warming to 1.5° C requires more than half of global emissions reductions to happen before 2030—a commitment the Biden administration made in its latest submission of the United States' Nationally Determined Contributions under the Paris Agreement.[101] In reality, for wealthy nations like the United States, which is also the largest historical emitter of greenhouse gases, even steeper and earlier reductions must be made, since poorer nations will require more time and carbon budget to develop.[102] To reduce emissions as rapidly as possible, mitigation must take full advantage of solutions that *already* exist and can be quickly deployed starting today.

The urgent need for near-term reductions means we cannot afford to wait for the commercial availability of green hydrogen to decarbonize sectors that already have decarbonization tools.

# IV IDENTIFYING THE PROMISING APPLICATIONS FOR GREEN HYDROGEN

This section explores the potential for various sectors to use green hydrogen as a cost-effective decarbonization tool. Below, we have sorted different applications in terms of their suitability for decarbonization with green hydrogen, using basic questions that policymakers can apply to any sector or potential hydrogen project. As a general principle, policymakers should never delay deployment of cost-effective decarbonization tools that are available today based on the hope that green hydrogen might become available in the future.

## 1. LEAST-REGRETS USES FOR GREEN HYDROGEN

### Displace fossil hydrogen in current uses as an industrial feedstock

As discussed in Section I, industry currently produces so much hydrogen from fossil fuels that hydrogen production is a significant climate threat. Green hydrogen could avoid these emissions without requiring new technologies for hydrogen use. Industrial clusters that have hydrogen customers grouped in a small geographic footprint would allow for supply to be delivered by dedicated pipeline (the cheapest mode of delivery), and leverage existing storage infrastructure.

As the energy transition proceeds, demand for oil refining and chemical fertilizer production should decrease: sustainable and zero-emission transportation would reduce reliance on petroleum, and sustainable practices would reduce reliance on chemical agriculture inputs. In the next decade, while oil refining is required to meet increasingly stringent fuel specification standards, hydrogen demand may grow in the refining sector, and it would be a win for both the climate and public health if these inputs are instead supplied by green, zero-emission hydrogen. However, the potential for green hydrogen to displace fossil hydrogen cannot be a justification for expansion of refineries or chemical fertilizer plants. It should only be considered as a clean feedstock for existing, polluting systems that must rapidly wind down to meet climate and environmental justice objectives.

## 2. SECTORS TO EXPLORE WITH CAUTION

### Maritime shipping

Global maritime transport accounts for roughly 3% of global greenhouse gas emissions, and is responsible for roughly 15% of global emissions of sulfur oxides and nitrogen oxides—pollution that disproportionately harms public health in port-adjacent communities.[103]

Inland vessels, ferries, and other smaller ships sailing shorter distances can already be powered using batteries and operate with zero-emissions.[104] The unexpected pace of technological progress in batteries has even led companies to begin building and piloting battery-powered zero-emission tankers and container vessels.[105] Given challenges to recharging batteries that need to cross thousands of miles of ocean, however, reliance on liquid fuels in international voyages is unavoidable for the foreseeable future.

Recent reports identify green hydrogen and green hydrogen-derived ammonia as a promising path to decarbonizing ships with longer voyages.[106] Green ammonia (derived from green hydrogen plus nitrogen in the atmosphere) is viewed as slightly more promising because it is easier to store and requires less space than pure green hydrogen for a given energy content.[107] If used in internal combustion propulsion systems, ships burning green hydrogen or ammonia will still emit air pollutants such as NOx (and unburned ammonia—a pollutant that is toxic to both humans and aquatic life).[108] To reduce air pollution, green ammonia or hydrogen should be used in fuel cells, a solution that is less established than combustion engines but is being piloted for some long-voyage vessels.[109]

| | | Are there currently technologies for using hydrogen in this sector? | Would use of green hydrogen require significant investments in hydrogen transportation and storage? | Are lower-cost decarbonization strategies available for this sector today? | Is green hydrogen likely to be necessary to decarbonize this sector? | Air pollution impacts of transition to green hydrogen |
|---|---|---|---|---|---|---|
| **LEAST-REGRETS USES FOR GREEN HYDROGEN** | Displace fossil hydrogen currently used as an industrial feedstock | Yes | Not if green hydrogen is produced on-site. | No | Yes | A transition to green hydrogen would avoid air pollution from current hydrogen-production practices. |
| **EXPLORE WITH CAUTION** | Maritime shipping | No | Yes | No | Yes | A transition to green hydrogen or green ammonia would reduce emissions from vessels, especially if they used fuel cells. |
| | Aviation | No | Yes | No | Yes | Potential for emissions reductions if planes use green hydrogen in fuel cells, rather than burning hydrogen. |
| | Industrial processes that require heat above 400°C (such as steel production) | Requires case-specific analysis | Yes | Partially | Maybe | Depends on what fuel the green hydrogen would displace. If a facility is currently burning fossil gas, a transition to green hydrogen combustion will not reduce (and may increase) NOx emissions. |
| | Long-term storage of renewable electricity paired with fuel cells | Yes, fuel cells that can deliver stationary power exist and are in operation around the world today. | Yes | No. Current technologies enable us to cost-effectively achieve 90% clean energy on the electric grid by 2035, but do not offer solutions for long-term storage of renewable energy. | Maybe. It is unclear what technology will emerge as the most cost-effective tool for long-term storage of renewable electricity. | Green hydrogen using fuel cells can eliminate on-site air pollution. |
| | Long-haul trucks and trains | Fuel cells are commercially available, but are still being piloted and tested for long-haul trucking in the United States (>200 miles a day) and line haul locomotives (cross country). | Yes | Partially | Maybe. Battery-electric and overhead catenary systems are the two primary alternatives for zero-emission long-haul transportation. Hydrogen fuel cells may be able to outcompete the demand for batteries and high-capacity charging for long, heavy-duty hauls, and the infrastructure costs of overhead lines. | A transition to green hydrogen fuel cells would avoid health-harming tailpipe emissions. |
| **REJECT THE HYDROGEN HYPE** | Combusting hydrogen in new, existing, or expanded fossil gas power plants | Current turbines can handle small amounts of blended hydrogen, but running on pure hydrogen requires yet to be demonstrated modifications. | Yes | N/A. However, unsubsidized solar and wind, even when paired with batteries, are much cheaper than gas plants running on even modest blends of hydrogen, which would have minimal greenhouse gas reduction benefits. | No, gas plants are best decarbonized by being decommissioned. | Hydrogen blends running in gas turbines are likely to increase NOx pollution. |
| | Industrial processes that require heat below 400°C (e.g., food and beverage processing, packaging, textile, and some chemicals processing) | No | Depends on facility | Yes | No | Burning hydrogen would cause more air pollution than electric alternatives. |
| | Gas-burning appliances in homes and commercial buildings | Gas-burning appliances can tolerate some blending of hydrogen into the gas mixture, but it is unclear how much. | Yes | Yes | No | Indoor air pollution would continue and may worsen. |
| | Cars, buses, and short- haul trucks | Yes | Yes | Yes | No | Like battery-electric vehicles, fuel cell vehicles have no tailpipe pollution. |

**Figure 6: Evaluating potential applications for green hydrogen**

These paths are preferred to both biofuels, which a World Bank report dismisses as "highly unlikely to be available at sufficient scale and to be sufficiently cost-competitive" and synthetic carbon fuels, which they conclude "involves multiple energy-intensive steps which leads to poor energy efficiency."[110]

### Aviation

Aviation emits more than 2% of global $CO_2$ emissions and is expected to rapidly rise.[111] Like maritime shipping, the aviation sector may not be able to rely on widespread electrification to eliminate emissions, given the limitations of batteries and charging for long-haul routes. Independent experts have identified using renewable electricity to produce hydrogen or kerosene (derived from green hydrogen) as a potential path to decarbonizing aviation, with some companies already piloting its potential for short-haul flights under 500 miles.[112] Some startups are investigating the potential for hydrogen-powered aviation, with some developing hydrogen "capsules" that would be interchangeable, and will be piloted in aircrafts powered by fuel cells capable of regional flights up to 700 miles, with a goal for actual flights by 2025.[113]

### High-heat industrial processes

Green hydrogen may play an important role in decarbonizing high-temperature industrial processes, such as steel production, that do not have electric decarbonization options. Steel production is an industry for which green hydrogen is an especially attractive decarbonization strategy because green hydrogen could provide both high-temperature heat and replace coking coal in the iron-ore reduction process. Meanwhile, many industrial processes use temperatures well within the range of lower-cost alternatives. Electric heat pumps will probably be the most cost-effective option for decarbonizing industrial processes that require heat up to 400°C.

Currently, about 40% of gas used for industrial heat is for temperatures less than 100°C—like for food, beverage, and textile processing, packaging, and some chemicals processing.[114] Even for higher temperature heating demands, other electricity based options are commercially established (e.g., electric arc furnaces, resistance, microwave and plasma heating). Electric arc furnaces are now used in some steel production and can reach temperatures up to 3500°C.[115]

### Long-haul trucks and trains

Hydrogen fuel cells are already in use in the transportation sector, but they are significantly more expensive, and would require significantly more renewable electricity, than battery-electric vehicles.[116] These constraints limit their potential to segments of the surface transportation sector where, like shipping and aviation, batteries are not soon expected to achieve necessary energy density or refueling needs for long, heavy-duty hauls. Locomotives that carry heavy freight across the country, for example, need so much energy that an entire rail car of batteries might be required where catenary or other electrified rail infrastructure is not feasible,[117] and some worry that battery weights could penalize the payload of long-haul trucks (though jurisdictions like California and Europe have passed additional zero-emissions vehicle weight allowances).[118] While some analyses show that the current and rapidly advancing state of battery cost and performance will overcome these concerns, the need for high energy density and fast refueling times makes hydrogen fuel cells a potential solution for these surface transportation segments.[119] A few truck manufacturers continue to explore hydrogen fuel cells for long-haul trucks,[120] and hydrogen fuel cells are being used to displace diesel engines in some locomotives.[121]

### Long-term storage of renewable electricity paired with fuel cells

The near-term focus for decarbonizing the electric grid should be dramatically increasing deployments of renewable resources and batteries—the mature technologies that can cost-effectively supply 80% of the United States' electricity by 2030 and 90% of electricity by 2035.[122] Achieving a zero-carbon grid will require a variety of energy storage technologies that can store renewable energy over different time scales. Green hydrogen's advantage is that it could economically store renewable energy for long periods of time with minimal energy

loss.[123] It is unclear whether green hydrogen will be able to compete against other long-term energy storage technologies, such as compressed air and electrochemical storage.[124]

**Importantly, fuel cells do not present the substantial air pollution concerns that come with combustion turbines, because fuel cells only emit water vapor.**

Fuel cells would be the appropriate technology for re-converting green hydrogen into electricity. Most importantly, fuel cells do not present the substantial air pollution concerns that come with combustion turbines because fuel cells only emit water vapor.[125] Further, fuel cells can operate at higher efficiencies (up to 60%) than combustion power plants (about 40%).[126] Fuel cells can be sited in urban settings near the customers who rely on them because they are quiet and do not emit air pollution, helping to reduce expensive investments in the transmission system and the risk of power outages when transmission lines fail.[127] Fuel cells are an established and commercially available technology, unlike burning pure hydrogen in power plant turbines. And because fuel cells rely on the same principal processes as electrolyzers (they are essentially electrolyzers that work in reverse) they are likely to benefit from the expected cost declines that will come from increased investment in green hydrogen.

The main drawback of fuel cells is that they tend to have smaller energy capacity compared to combustion turbines and have initially been limited to meeting smaller energy demands. But this is changing—fuel cells can provide power for systems as large as utility power stations, and groups of modular fuel cell systems have been joined to create small power plants up to 63 MW in size.[128] While the larger deployments of solar and wind necessary to generate surplus renewable energy continue to be scaled, higher capacity fuel cell technology and costs are likely to improve. In the meantime, it is important that policymakers and energy system planners seek ways to prioritize their deployment in place of alternatives that would rely on combustion and its corresponding air pollution.

## 3. SECTORS WHERE HYDROGEN IS NOT A SOLUTION

In these sectors, there are unique and likely insurmountable challenges to cost-effectively deploying green hydrogen, in addition to the cross-cutting challenges described in Section II. Please see page 18 for information about the infrastructure needed to safely transport and store hydrogen and page 17 for information about the deployments of wind and solar resources that will be necessary to drive down the cost of green hydrogen.

### Combusting in fossil gas power plants

Several entities have supported proposals for investments in gas-fired power plants with claims that their new fossil fuel infrastructure could one day transition to burning green hydrogen.[129] These proposals often lack meaningful consideration of the substantial barriers to retrofit a gas plant to wholly or even partially run on green hydrogen. The project proponents' vague claims about hydrogen are likely a tactic for dismissing climate and public health concerns about expanded fossil fuel reliance.

There are no commercially available power plant turbines now that can burn pure hydrogen. Without this technology, even power plants that have access to green hydrogen will continue to burn a mixture of hydrogen and fossil gas. Even burning a gas blend with 50% green hydrogen and 50% methane would require industry to overcome significant obstacles. Hydrogen's energy density (one-third of fossil gas), molecular size (the smallest of all molecules), flammability, and flame speed (an order of magnitude faster than fossil gas)[130] all pose challenges to retrofitting gas plants to run on green hydrogen, which scale with increasing concentrations of hydrogen in the power plant's fuel blend. Beyond the turbine itself, running a gas turbine on pure hydrogen requires different fuel delivery piping and components; different gas turbine controls, ventilation systems, and enclosures; and different selective catalytic reduction systems for

## THE INTERMOUNTAIN POWER PROJECT

The project with the most advanced plans for transitioning to green hydrogen is the Intermountain Power Project in Utah. This facility has access to underground salt caverns for storing hydrogen, which do not exist in most parts of the country, and abundant renewable generating capacity as well as existing transmission lines. This intersection of low-cost storage, delivery, and energy capacity conditions is likely to be extremely limited across the United States.

NOx removal.[131] Many of these are also needed for high blends of hydrogen mixed with traditional gas.[132]

Even if logistical challenges can be overcome to allow gas-fired power plants to burn a gas blend with even 30 to 50% green hydrogen, this feat will have a modest effect on greenhouse gas emissions. For example, a 30% hydrogen blend would only achieve a 12% $CO_2$ reduction. This is because of hydrogen's low energy density, which means that large volumes of hydrogen deliver less energy than the methane in fossil gas.

The air quality impacts of combustion turbines will not only persist if they transition to hydrogen, but will worsen absent satisfactory advances in emission control technology. Indeed, it is unclear if and when industry will develop turbines that can burn hydrogen without violating air quality standards. Transitioning to hydrogen-burning turbines threatens to increase air pollution because hydrogen burns at a higher temperature than methane. A study conducted by General Electric on its combustion turbines found that a 50/50 mixture of hydrogen and fossil gas (by volume) increased concentrations of NOx in gas exhaust by 35 percent.[133] A recent report by a gas turbine industry association warned that these higher flame temperatures will produce more health-harming NOx emissions "if no additional measures are undertaken."[134] The industry association recommended that "[s]ome flexibility might be needed on NOx limits," noting that complying with pollution standards will be even more challenging if governments adopt the stronger NOx limits it foresees in the future.[135] For these reasons, regulators should not allow any increases in hydrogen blending without

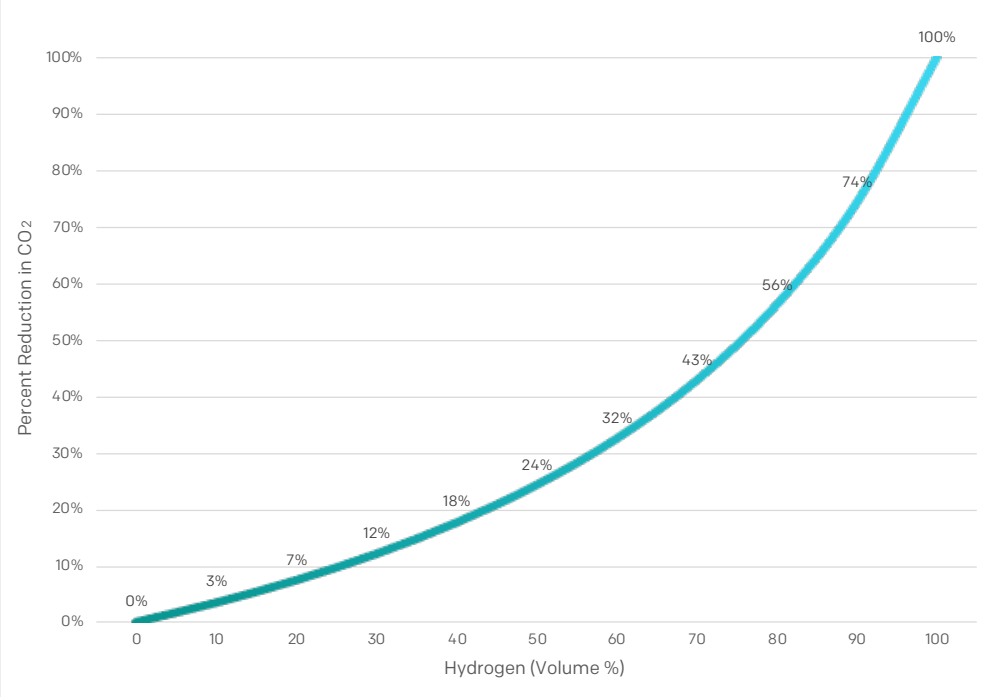



**Figure 7: Relationship between $CO_2$ emissions from combustion and hydrogen/methane fuel blends (volume %)**

## GREENWASHING SPOTLIGHT

Danskammer Energy LLC is proposing to build a new 636 MW fossil gas combined cycle plant in the Town of Newburgh, New York. Under the Climate Leadership and Community Protection Act ("CLCPA"), New York has committed to achieving ambitious greenhouse gas reductions by 2030 and 2050, 70% renewable electricity by 2030, and a zero-emission electricity sector by 2040. Danskammer maintains that its proposed fossil gas plant will comply with state law because the proposed plant could theoretically someday convert to operation on hydrogen or another zero-carbon fuel and has floated the possibility of a hydrogen pilot study post-construction. However, the Company does not explain—and does not appear to know—how operating the proposed plant on hydrogen would actually work, including where the hydrogen might come from and how it would be transported to and stored on-site. When asked for additional details, Danskammer conceded that it is not proposing to operate on green hydrogen as part of the project under review, basic details on the potential hydrogen pilot project are not available at this time, and further approvals would be necessary in connection with any proposal to operate on hydrogen. Unsurprisingly then, Danskammer does not commit to a hydrogen transition and does not even plan to develop a scope for any pilot study until sometime after its proposed plant is approved to run on fossil gas. Moreover, after reviewing Danskammer's application for a facility air permit, the Commissioner of the New York State Department of Environmental Conservation tweeted that the application does not justify the project or show compliance with the CLCPA.

Source: Basil Seggos, https://twitter.com/basilseggos/status/1410334434595946496.




reviewing the adequacy of a facility's emission controls and establishing an emissions monitoring program. Regulators should set specific limits on a facility's NOx emissions during startup periods; gas turbine NOx emissions often spike before their pollution controls warm up and a transition to hydrogen could exacerbate these spikes of uncontrolled emissions. This is a public health concern for residents living near such a facility and especially in non-attainment areas, which may potentially increase the disparate impact many fence-line communities already bear in this country. Without sufficiently improved pollution control technology, another alternative would be to lower the flame temperature by "derating" the turbine, which means that the unit would not operate at its full nameplate capacity.[136] This strategy could increase the risk of power outages if grid planners had assumed these plants will be able to perform at capacity when needed.

Water use is another environmental burden that will persist regardless of whether combustion turbines transition to green hydrogen. Fossil-fueled power plants are the nation's top user of fresh water and demand tremendous amounts of water for cooling. As the climate changes, there will be less fresh water available to cool these power plants—putting their continued operation at risk.[137]

Finally, policymakers should not permit the buildout of new gas-fired power plants under the assumption that it will be economical to operate these facilities with green hydrogen. As mentioned above, a company that recently proposed a new gas plant in Newburgh, New York estimated that hydrogen in 2040 will cost $45/MMBtu in nominal dollars.[138] In contrast, the most recent Energy Information Administration 2020 Annual Energy Outlook projects

natural gas to cost well below $4/MMBtu in 2040 (in 2019$) in its Reference Case.[139]

### Gas-burning appliances in homes and commercial buildings

Burning fossil fuels to keep us warm in the winter, heat our water, and power other appliances collectively contributes about 10% of the nation's greenhouse gas emissions.[140] Climate policy poses an existential threat to America's gas companies because the most cost-effective way to tackle these emissions is by transitioning from appliances that burn fuel to electric appliances that run on a decarbonized power grid.[141] In the face of this threat, hydrogen has emerged as a new tool for the gas industry to sow confusion and combat measures that would help homes and businesses transition to electric appliances.

Multiple independent studies show that there is a weak economic case for deploying green hydrogen in buildings through the gas distribution grid.[142] The main reason is the superior efficiency of heat pumps, which use small amounts of renewable electricity to move ambient heat to where it is needed. One recent Pacific Gas & Electric Company-funded study found that California could save $20 billion by choosing a high electrification pathway instead of relying on renewable gases like hydrogen and synthetic methane in buildings.[143] Heat pumps for space and water heating are not only the cheapest of all zero-carbon options—in many instances, their superior efficiency means they will yield cost savings relative to conventional gas-based heating systems.[144]

There are several reasons why green hydrogen is a bad fit for addressing the pollution from gas-burning appliances:

(1) **Injecting green hydrogen into the gas system could require significant investments into a system that was not designed for hydrogen**. In California, the regulated gas utilities have proposed a pilot project to study how much hydrogen they might safely inject into the gas distribution system, and under what conditions. The utilities identified numerous potential safety and reliability risks they intend to study. For example, the elastomers and rubbers that seal many pipeline components can swell or develop voids after exposure to pure hydrogen; hydrogen can cause embrittlement of steel pipes; and the utilities do not know how much hydrogen they can

## BEWARE THE HYPE AROUND HYDROGEN BLENDS

Southern California Gas Company and San Diego Gas & Electric Company brag in press releases about proposing "groundbreaking" research that could allow them to deliver gas with an "industry-leading" 20% hydrogen blend, calling it a "key milestone in our efforts to decarbonize our energy system."* If these companies find a way to safely deliver a gas mixture that is 20% green hydrogen and 80% fossil gas, their gas will still be a major climate threat. Because of hydrogen's low energy density, burning a gas blend with 20% green hydrogen will only reduce carbon dioxide emissions by about 7%. This is close to the ceiling for how much hydrogen the gas companies could deliver to homes and businesses before creating an explosion risk in gas-fired residential appliances, which is around 25% hydrogen.**

* Southern California Gas Company & San Diego Gas & Electric Company, *SoCalGas and SDG&E Announce Groundbreaking Hydrogen Blending Demonstration Program to Help Reduce Carbon Emissions* (Nov. 23, 2020), https://www.prnewswire.com/news-releases/socalgas-and-sdge-announce-groundbreaking-hydrogen-blending-demonstration-program-to-help-reduce-carbon-emissions-301178982.html.

** Jeff St. John, *Green Hydrogen in Natural Gas Pipelines: Decarbonization Solution or Pipe Dream?*, Greentech Media (Nov. 30, 2020), https://www.greentechmedia.com/articles/read/green-hydrogen-in-natural-gas-pipelines-decarbonization-solution-or-pipe-dream.

safely store in the underground formations that they rely on for gas storage. Because hydrogen molecules are much smaller than methane molecules, utilities may also need to upgrade their infrastructure to prevent it from leaking into the atmosphere. When a pipeline carries a blend of hydrogen and methane, hydrogen can leak at three times the rate of methane.[145] Regulators should not let gas utilities force their captive customers to bear the costs of modifying pipeline infrastructure to carry hydrogen safely and with minimal leakage. It is unreasonable for resources to go toward hardening a gas system that has no role in a zero-emission future, rather than reserving resources for building electrification.

(2) **Even after blending in green hydrogen, the gas system hits a dead end as a decarbonization tool**. Regardless of whether retrofits could theoretically enable the gas system to deliver pure hydrogen to homes and businesses, local gas utilities could not do so. At most, gas utilities can blend limited amounts of hydrogen with methane because appliances that were designed for methane gas cannot safely burn pure hydrogen.[146] The most optimistic scenarios estimate that the gas system that serves homes and most businesses could only handle up to 20% hydrogen by volume—representing just 7% of the energy in the gas pipeline system because hydrogen is less energy dense than methane.[147] In that case, fully decarbonizing the gas system would require the gas utilities to procure enough renewable methane to supply the remaining 93% of energy need on the system. There is no feasible way to displace 93% of the country's fossil gas demand with non-fossil sources of methane. Even under the gas industry's "high resource potential" scenario, methane from landfills, animal manure, food waste, and water treatment facilities could displace less than 9% of the fossil gas this country currently uses each year.[148] The same report identifies various methods of creating additional methane that could displace up to 19.5% of America's gas consumption in its most aggressive scenario.[149] The gas industry's claims about the potential for supposedly "renewable natural gas" may be overly optimistic. A report by the Union of Concerned Scientists found that there is only enough potential biomethane supply to displace about 3% of California's fossil gas use.[150] Other sources of "renewable natural gas" are being studied, but are decades

## BIOMETHANE

Biomethane—sometimes referred to as "biogas," "renewable natural gas," or "RNG"—is methane generated through the decomposition or gasification of organic matter. The most common sources of biomethane are landfills, animal manure from factory farms, wastewater treatment plants, forest and agricultural waste products, or crops grown for the specific purpose of converting into energy.

While gas utilities—often in partnership with industrial agribusiness—have promoted biomethane as a drop-in alternative to fracked gas, the actual supply of non-fossil gases is extremely limited. And despite the industry's branding of this gas as "renewable," much of it comes from sources that are highly polluting, and can perversely increase greenhouse gas emissions. The small fraction of biomethane that is genuinely sustainable to produce cannot justify anything close to the current gas distribution system, and is best allocated to niche, hard-to-electrify end uses.

For a more detailed look at the industry's misleading claims about biomethane, see Earthjustice's report with Sierra Club: *Rhetoric vs. Reality: the Myth of "Renewable Natural Gas" for Building Decarbonization*. Sasan Saadat et al., *Rhetoric vs. Reality: the Myth of "Renewable Natural Gas" for Building Decarbonization* (July 2020), https://earthjustice.org/report/building-decarbonization.

away from commercialization.[151] Even if a gas company could buy a blend of zero-carbon gas, the cost would be exorbitant—potentially 8 to 17 times the cost of natural gas.[152] Thus, the current and potential future supplies of non-fossil gases do not alter the imperative to quickly and dramatically reduce gas throughput.

(3) **Injecting hydrogen into the gas system does not eliminate—and may increase—the indoor air pollution from gas-burning stoves, furnaces, and other appliances**. Unlike electric appliances, all gas-burning appliances emit nitrogen oxides, pollution that contributes to respiratory and heart diseases.[153] Under the status quo, gas combustion for heating and cooking results in significant NOx pollution and other combustion byproducts that would be considered illegal if measured outdoors. Recent studies show that children growing up in homes with gas stoves have a 42% increased risk of developing asthma symptoms.[154] In their joint application to the California Public Utilities Commission to research the compatibility of hydrogen blends with their infrastructure, the California gas utilities acknowledged that blends of hydrogen and methane "may yield higher NOx emissions than natural gas because hydrogen burns faster than natural gas, which increases combustion temperatures and reduces ignition lag. . . . therefore, additional emissions testing should be completed with natural gas end-use equipment operating with hydrogen blends."[155] Regulators should not allow gas companies to inject hydrogen into their

## GREENWASHING SPOTLIGHT

Across California, local governments have adopted policies that encourage new buildings to use all-electric appliances as a cost-effective strategy to reduce greenhouse gases. The nation's largest gas utility, Southern California Gas Company (SoCalGas), has repeatedly fought these commonsense measures by urging policymakers to instead consider the possibility that gas companies' infrastructure could deliver hydrogen and other so-called "renewable" gases. For instance, the company made the following argument in its attempts stop Ventura County from blocking the build-out of fossil gas infrastructure to new homes:*

> SoCalGas urges the County to consider other GHG emission-reduction strategies that are scalable and easier to implement, more resilient and more affordable. Specifically, the use of renewable gasses such as hydrogen and renewable natural gas (RNG), are low carbon to negative fuels that can dramatically reduce county greenhouse gas emissions and provide optionality and flexibility for the energy system.

This is self-serving hype from the gas company. Despite its vague claim that green hydrogen is "more affordable" and "easier to implement" than using all-electric appliances in new homes, SoCalGas has never revealed the potential cost of procuring green hydrogen and upgrading its infrastructure to handle hydrogen blends. Promoting the interests of its shareholders, SoCalGas is invoking the future potential of hydrogen to stop policymakers from choosing climate solutions that are cost-effective today.

* SoCalGas, Comment letter RE: County of Ventura – Draft 2040 General Plan Update EIR (Feb. 28, 2020) at 12.

distribution systems unless independent researchers find that doing so will not further degrade indoor air quality.

### Cars, buses, and regional trucks

Green hydrogen is not an attractive technology for decarbonizing most vehicles on the road because battery-electric vehicle technology provides a straightforward path for cars, buses, and trucks. In the market segments where battery-electric and hydrogen options are available, the battery-electric options are cheaper to purchase and operate than their hydrogen competitors, even when the hydrogen vehicles run on less expensive hydrogen from fossil fuels.[156] By the mid-2020s, researchers expect many battery-electric vehicles to have an even lower cost of ownership than vehicles with internal combustion engines.[157] Battery-electric light-duty vehicles will likely reach upfront price parity with combustion engines between 2022 and 2024, at which point they will produce operational savings relative to conventional vehicles at no added cost.[158] Though manufacturers of fuel cell vehicles could reduce upfront purchase prices by scaling up production, the economics of fueling a battery-electric vehicle with renewable energy have inherent advantages over fueling a fuel cell vehicle with green hydrogen. Hydrogen cars require more than 2 to 3 times as much renewable energy as battery-electric cars because so much energy is lost in the process of compressing and transporting hydrogen and converting it into electricity in fuel cells.[159]

Some efficiency improvements are possible. Nonetheless, a recent study found that to meet climate goals, "in comparison to electric vehicles, hydrogen-based propulsion technologies will reach market readiness too late."[160]

Given the economic advantages of renewable electricity over green hydrogen as a vehicle fuel, fuel cell vehicles will likely only be viable in the shrinking market segments that lack battery-electric options. Even for long-haul trucking, where hydrogen was once thought to be necessary for decarbonization, battery-electric vehicles are emerging as a cost-effective and low-risk mitigation pathway thanks to rapidly improving battery technology.[161] Recent studies find that these dramatic improvements can render long-haul battery-electric trucks with 500-mile range both technically feasible and economically compelling.[162] About 80% of trucks travel less than 500 miles,[163] making battery-electric technologies the best option for the vast majority of trucks.

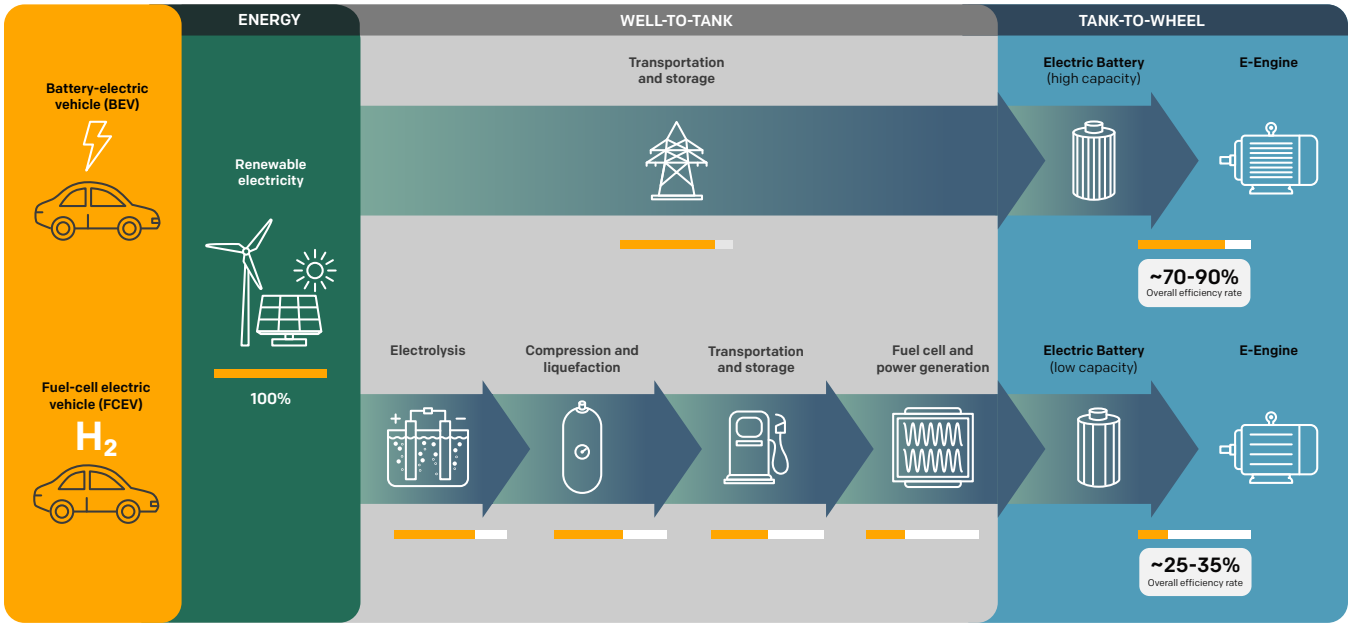



**Figure 8: Comparing the efficiency of renewable energy in battery and fuel cell vehicles**

Data source: Volkswagen (2020)

Recognizing the challenges for fuel cell vehicles, industry is rethinking investments in hydrogen. Scania, one of the world's largest truck and bus manufacturers, decided to end its fuel cell vehicle program because "three times as much renewable electricity is needed to power a hydrogen truck compared to a battery electric truck" and maintenance is more challenging for hydrogen vehicles than their battery-electric competitors.[164]

Volkswagen is also focusing on electric vehicles, with its chief executive officer declaring that "You won't see any hydrogen usage in cars. . . . Not even in 10 years, because the physics behind it are so unreasonable."[165] Likewise, Mercedes-Benz is ending its hydrogen car program because it could not scale up sales and production enough to make hydrogen cars cost-competitive.[166]

## GREENWASHING SPOTLIGHT

Toyota is advertising its hydrogen fuel cell car, the Mirai, with the misleading claim that "[t]he more you drive, the more you clean air." The idea behind this claim is that the car's air intake has a filter that captures particulate matter and other impurities in the air before sending oxygen to its fuel cell. However, Toyota's ads ignore the emissions from producing hydrogen, even though almost all of the hydrogen in the United States is produced from fossil fuels through a process that releases significant health-harming pollution. Ultimately, these ads are likely to give consumers the false impression that they can help improve air quality by driving more often.




Source: TOYOTA MIRAI, Air Purification System (last visited July 30, 2021), https://www.youtube.com/watch?v=VX8p0mG7pLY.

# CONCLUSION

Recently, hydrogen has captured the attention of the press and policymakers, partly because green hydrogen may become a climate solution for sectors that have long seemed out of reach for renewable energy. However, hydrogen hype is also flowing from industry trade associations that represent the oil and gas industry, which produce the vast majority of hydrogen in use today from fossil fuels. For the oil and gas industry and for other incumbents of the fossil energy system—like certain manufacturers of combustion vehicles, turbines, and boilers and companies that profit from building gas pipelines—hydrogen may offer a path to continued relevance and investment under potential climate policies.

While hydrogen can—and likely must—complement traditional renewables and electrification, policymakers should only promote hydrogen that is genuinely compatible with a zero-emission future. Today, more than 99% of the hydrogen that industry produces in the United States is made from fossil fuels through a process that emits massive amounts of health-harming pollution into neighboring communities. Appropriate investments in green hydrogen, which is made from renewable electricity, are no excuse for expanding or continuing hydrogen production that threatens the climate and public health.

Further, policymakers should understand the limits of green hydrogen's economic potential. Green hydrogen is not a useful tool for sectors that can decarbonize by transitioning to electric technologies and relying on a renewable power grid. It will always be more cost-effective to use renewable energy directly from the grid than to use green hydrogen; due to the inefficiency of converting renewable energy into hydrogen, powering equipment with green hydrogen requires several times as much renewable energy than doing the same job with clean electricity. Therefore, policymakers should focus on supporting green hydrogen in sectors that lack feasible electric options, such as maritime shipping.

Currently, industry trade associations are advocating for the use of a broad range of hydrogen sources and seeking public support for using hydrogen in sectors that have more cost-effective strategies for transitioning to renewable energy. Policymakers must carefully scrutinize these requests. The window to rapidly transition to a just, zero-emission energy system is narrowing. There is no time to waste with distractions or missteps. To chart a clear course, we must distinguish green hydrogen's true potential from fossil fuel industry spin, and reclaim it for a renewable future.

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RIGHT TO ZERO

# Exhibit DD. *TAMCO v. South Coast Air Quality Management District* (2014) SCAQMD Hearing Board Decision Case No. 5972-1

**BEFORE THE HEARING BOARD OF THE**

**SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT**

| | |
|---|---|
| In the Matter of<br><br>TAMCO,<br>[Facility ID #018931]<br><br>Petitioner,<br><br>vs.<br><br>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT,<br><br>Respondent. | Case No. 5972-1<br><br>**FINDINGS AND DECISION OF THE HEARING BOARD**<br><br>**HEARING DATES:** March 25, May 28-29, June 5 and 19, and August 27, 2014 (final decision and vote on August 27) and September 18 and 24, 2014 (solely for purpose of reducing decision to writing)<br>**TIME:** 9:00 a.m.<br>**LOCATION:** 21865 Copley Drive<br>Diamond Bar, CA 91765 |

On January 9, 2014, TAMCO, located at 12459-B Arrow Route, Rancho Cucamonga, CA 91739, filed an appeal of its Title V permit issued by the Executive Officer of the South Coast Air Quality Management District (District) providing for no RECLAIM (Regional Clean Air Incentives Market) SOx allocation for its electric arc furnace (EAF). Hearings were held on the following dates: March 25, May 28, May 29, June 5, June 19, and August 27. Five members of the Hearing Board heard the appeal: Edward Camarena, (Chair and Engineering Member)[1]; Julie Prussack, (Vice Chair and Legal Member); Robert F. Wayner, M.D. (Alternate Medical Member); Patricia Byrd, (Public Member); and David Holtzman, (Public Member). Petitioner was represented by

[1] Health and Safety Code section 40501.1(a) specifies certain types of Hearing Board members and their required qualifications.

Thomas D. Long and Byron P. Gee, Attorneys-At-Law, Nossaman, LLP. Respondent, Executive Officer, was represented by William B. Wong, Principal Deputy District Counsel. The public was given the opportunity to testify. Evidence was received, and the case submitted. The Board deliberated and made a final decision on August 27, 2014. On September 18 and 24 the Board held two additional hearings for the sole purpose of publicly reducing its findings and decision to writing. The Hearing Board finds and decides as follows:

## SUMMARY

This case was brought by TAMCO, a steel minimill that recycles scrap metal to make steel rebar. The scrap steel is melted in an electric arc furnace (EAF) that primarily uses high voltage electricity as a heat source to melt the scrap metal. Oxygen and carbon[2] are injected into the steel to promote the melting process. The oxygen reacts with the sulfur in the scrap steel and carbon to form SOx (sulfur oxides) that exits the EAF. (First Amended Petition (FAP), at 2.) TAMCO's EAF has been in operation since decades before the October 15, 1993 adoption of RECLAIM, which is further described below. (2 Transcript ("Tr.") 250.) District Rule 301 required TAMCO to report the quantity of SOx being emitted by its EAF on its annual emissions report (AER). Nevertheless, TAMCO failed to report any SOx emissions from its EAF for every year since the start of its operation until sometime after May 31, 2012. Since that time, TAMCO has reported about 30 tons/year of SOx emissions from its EAF, including for prior years, dating back to at least 1989. According to District Rule 2001(b), TAMCO has thus exceeded the threshold 4 tons of SOx/year, requiring TAMCO to be placed into RECLAIM for SOx emissions. *See* District Rule 2001(b) (stating, in relevant part, "the Executive Officer will include facilities [in RECLAIM] if…emissions fee data…shows four tons per year or more of NOx or SOx…")[3]. This was a unique

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[2] Carbon is introduced in the form of petroleum coke, which contains sulfur. (2 Tr. 272-73.)

[3] TAMCO was already in RECLAIM for its NOx (oxides of nitrogen) emissions.

case for the District, involving a facility just entering into SOx RECLAIM when the facility should have been entered at the start of the program decades earlier.[4]

The District determined that no SOx allocation could be issued to TAMCO for its EAF, because under Rule 2002(c)(2)(D), TAMCO failed to report a SOx emission factor in its 1989 AER. (4 Tr. 518.) The District informed TAMCO that it would receive no SOx allocation for its EAF in February 2013. (FAP, at Exh. B.)

On July 19, 2013, TAMCO submitted a revised 1989 AER indicating that its EAF had emitted over 30 tons of SOx in that year. (FAP, at Exh. G.) The District has not approved the revised 1989 AER. Rule 2002(c)(1) states that TAMCO's starting allocation would be calculated by multiplying the throughput of TAMCO's EAF reported in 1989 with "the applicable starting emission factor for the subject source or process unit as specified in . . . Table 2." After the required engineering review, the District found no applicable emission factor on Table 2 for the EAF.

On December 10, 2013, the District therefore issued TAMCO a final Title V permit (after submission of a draft Title V permit renewal to EPA for its review) that contained no SOx allocation for TAMCO's EAF. (Exh. I.) In this appeal, TAMCO challenged that decision and requested that it be given a starting SOx allocation calculated and derived as if it had entered RECLAIM at the start of the program, taking into account any reductions of its SOX allocation required later by the RECLAIM rules.

## PROCEDURAL BACKGROUND

On January 9, 2014, TAMCO filed its original petition, appealing the Executive Officer's action, arguing that the Executive Officer was mandated to provide a starting SOx allocation to TAMCO pursuant to Rule 2002(c)(1) based on the emission factor for the EAF as claimed by

[4] There were a number of facilities that requested amendments to their SOx RECLAIM allocations after the start of the program. However, those facilities made such requests within just a few years of the program's inception. (Exh. K at II-1-2; 4 Tr. 557-58.) Only one other already-existing facility entered SOx RECLAIM nearly 20 years after the program's start, but that facility did not request a RECLAIM allocation for SOx. (*See* 2 Tr. 259; 3 Tr. 312-13.)

TAMCO in its recently revised 1989 AER. On March 4, 2014, the District filed a demurrer to TAMCO's petition arguing that, even assuming TAMCO's factual allegations were true, TAMCO would get no relief since the Executive Officer has no authority under Rule 2002 to create a new category and emission factor not present on Table 2, and the Hearing Board has no authority to require it. On March 25, 2014, the Hearing Board unanimously sustained the District's demurrer with leave to amend.

On April 10, 2014, TAMCO filed its first amended petition, claiming this time that Rule 2002(c)(2)(C) mandated the Executive Officer to classify TAMCO's EAF in the same Table 2 category specified for a gray iron cupola[5] or as a miscellaneous source. TAMCO also argued that the starting emission factor to determine its allocations must be the one it used in its 1989 amended AER.

On May 28, 2014, TAMCO called the same two witnesses to testify that had also previously filed declarations on behalf of TAMCO: Carol Coy, a former deputy executive officer for engineering and compliance with the District; and Joe Hower, a principal at ENVIRON. Their testimony lasted through two days of hearings, ending on May 29, 2014. At the end of their testimony, both parties agreed to enter TAMCO's Exhibits A-T, and the District's Exhibits 1-18 into evidence, and they were so entered. The District then made an oral motion to dismiss pursuant to Hearing Board Rule 5(a)(3).

After both sides presented argument, the Hearing Board deliberated and rejected the motion to dismiss, 4-1, with Ms. Prussack dissenting. As a result, the District put on four witnesses over the course of three days of hearings: May 29, June 5, and June 19, 2014. The witnesses were Rudy Eden, Laboratory Services and Source Test Engineering manager; Marco Polo, Air Quality

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[5] TAMCO specifically alleged that the District should have fit the EAF within Table 2's "Iron/Steel Foundry" category. (FAP at 3.) The only equipment listed (as "fuel type") under this broad industry category, however, is "gray iron cupola." We discuss later in this Decision the error in relying solely on the descriptive words in Table 2 for categorization of equipment under Rule 2002. For simplicity, we refer to this category as "gray iron cupola" throughout this Decision.

Engineer; Mohan Balagopolan, Senior Permitting Manager and Danny Luong, Senior Enforcement Manager.

Over the course of these hearings, additional exhibits were submitted by both parties, and TAMCO Exhibit U and District Exhibits 22 and 23 were received into evidence. The parties submitted closing briefs on August 20, 2014, and made closing statements on August 27, 2014. The Hearing Board deliberated that same day, and a majority voted to uphold the District's issuance of the permit and deny TAMCO's appeal. Two Hearing Board members, Mr. Holtzman and Dr. Wayner, voted in dissent.

## CASE BACKGROUND

RECLAIM

On October 15, 1993, the District Governing Board adopted the Regional Clean Air Incentives Market program, commonly known as RECLAIM. RECLAIM was an innovative program, replacing command-and-control regulations with a market-based incentive program. That is, command-and-control would be replaced with a system of facility caps on NOx and SOx emissions with declining balances of allowable maximum emissions, expressed by the facility permit's declining yearly allocation levels. In specifically authorizing the adoption of RECLAIM, the Legislature required the District's Governing Board to design RECLAIM so that 7 findings could be made expressly by the Board. Health and Safety Code §§ 39616(c)(1-7). The first finding was that RECLAIM would result in equivalent or greater emission reductions at equivalent or less cost than the command and control regulations and future air quality measures RECLAIM would subsume. The second finding reinforced the first finding by ensuring RECLAIM had a level of enforcement and monitoring to ensure compliance with the first finding's emission reduction requirements.

The District commenced development of RECLAIM in 1990 with extensive studies, committee oversight, and public outreach. (Exh. 13, at EX-6.) Because RECLAIM would start during a recession, a facility's starting allocation could be based on production levels prior to the recession, a period of time from 1989 to 1992. RECLAIM was also designed to be facility-

specific, and as a result, hundreds of staff hours were spent developing emission factors for specific equipment. (Exh. G, I-4-1.) Emissions surveys were sent to each facility (Exh. 14, II-D-1 to D-6), as well as draft allocations for comments. (Exh. 13, II-E-1 to E-29.) Staff met with individual facilities to discuss their proposed allocations. (Exh. G, I-4-1.)

To reflect the emission reductions to be achieved by command and control regulations, the Governing Board specified starting emission factors in Tables 1 (for NOx) and 2 (for SOx) of District Rule 2002 for all source categories, which had been reported to the District in a facility's annual emissions report (AER). In addition, to reflect emission reductions to be achieved by future air quality measures and rules, the Governing Board specified ending emission factors for those same source categories in Tables 1 and 2. For SOx ending emission factors contained in Table 2, there was a Tier I control measure A-F-1 reflecting a 20% allocation reduction from the year 2000 allocation level. (4 Tr. 495-497.)

To ensure that reductions were achieved, RECLAIM also required stringent monitoring and reporting. Continuous Emission Monitoring Systems (CEMS) were required for major sources of SOx, which include those emitting over ten tons per year. (Rule 2011(c)(1)(G). )

TAMCO specified 1989 as its selected production year for RECLAIM starting allocations. In its 1989 AER, TAMCO only reported substantial NOx emissions from its EAF. As a result, Table 1 (NOx) has a category for steel foundry, electric arc furnace. However, TAMCO failed to report a SOx emission factor for the EAF and reported zero SOx emissions for it in its 1989 AER.[6] As a result, Table 2 (SOx) has no similar category for TAMCO's EAF, and the District determined

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[6] District guidance on revising AERs required the submittal of a copy of the 1989 AER with revisions marked by hand. (*See* FAP, Exh. G, Attachment B at 15.) Here in the row for the EAF, entered as EO1913, in the Sulfur Oxides column, 0.20 is entered in the small box and 62,190 in the larger box. Both are hand written. There is no other entry. This indicates that on this page of the original 1989 AER, TAMCO left those boxes blank and thereby failed to report an emission factor for the EAF and failed to report SOx emissions for the EAF. Further, on page 21 of Attachment B to Exhibit G under the column for Sulfur Oxides in row D (for the EAF) there is a printed zero with a strike through and 62,190 entered by hand. This shows that the 1990 AER reported zero SOx emissions from the EAF and that the revised AER filed on or about July 19, 2013 reported 62,190 lbs/year SOx.

that no SOx allocation could be issued to TAMCO's EAF pursuant to Rule 2002(c)(2)(C). (4 Tr. 518.)

## DISCUSSION

### I. ISSUE IN DISPUTE[7]

The main issue to be decided is whether or not the Executive Officer properly issued TAMCO's Title V permit with no SOx allocation for TAMCO's EAF. That answer hinges on the answer to the following sub-question: whether or not District Rule 2002(c)(2)(C)[8] mandates the Executive Officer to fit TAMCO's EAF into a pre-existing category of Table 2, and in particular, the gray iron cupola category?[9]

### II. STANDARD OF REVIEW

Health and Safety Code § 42302.1 defines the standard of review applicable to permit appeals such as this one: "The hearing board shall . . . render a decision on whether the permit was properly issued." In an earlier appeal involving dairies, this Hearing Board dealt with the meaning of "proper" in the similar context of Health and Safety Code § 40713, which addresses appeals of disapprovals of emission reduction credit (ERC) applications. In that appeal, commonly referred to as the dairy cases, the Hearing Board established legal guidance for determining whether Executive

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[7] The District actually raised another issue in the event that the Hearing Board ruled in favor of TAMCO on the main issue. That is, whether or not laches bars consideration of TAMCO's amended 1989 AER. Because the Hearing Board ruled in favor of the District on the main issue, the Hearing Board did not address the District's laches argument.

[8] While the parties characterize the dispute as one over the starting emission factor; in practical terms, because TAMCO is entering RECLAIM after the year 2000, the real battle is over the ending emission factor, which takes effect in the year 2000. *See* District Rule 2002(d). However, for purposes of this case, the legal difference is immaterial, since Rule 2002(d)(1)(C) is identical to Rule 2002(c)(2)(C).

[9] In its Reply Brief filed on May 28, 2014, its Closing Brief, filed on August 20, 2014, and its closing statement, TAMCO no longer argued that its EAF should be fitted into the miscellaneous categories listed in Table 2. "Issues as to which an appellant provides no argument or discussion are deemed waived and are properly disregarded." *Oviedo v. Windsor Twelve Properties, LLC*, 212 Cal. App. 4th 97, 108 (2012), as modified (Nov. 27, 2012), reh'g denied (Dec. 6, 2012), as modified (Dec. 18, 2012), review denied (Apr. 10, 2013). While that issue is not relevant to the decision of this case, we note that TAMCO may have waived the issue that its EAF should be fitted into the miscellaneous category of Table 2. TAMCO certainly failed to pursue or prove these claims as discussed further below.

Officer action was "proper." The Hearing Board determined, based on that guidance, that Executive Officer action in the dairy cases was "proper." (A copy of that decision was attached as District Exh. 24.) That decision was then appealed to the Los Angeles Superior Court, which upheld the Hearing Board's decision. (A copy of that court decision was attached as District Exh. 25.)

This Hearing Board finds that its legal guidance in the dairy cases is applicable here to determine whether the Executive Officer's action was proper under Health and Safety Code § 42302.1. Applying that guidance, TAMCO was required to prove that the Executive Officer's determination that the District was not mandated to fit TAMCO's EAF into an existing Table 2 category was "wrong" – or in the language of Section 42302.1 not "proper" – in light of all of the evidence before the Hearing Board.

That guidance provides that the use of "proper" does not allow the Hearing Board to substitute its judgment for that of the Executive Officer, since he is possessed with the necessary technical expertise and responsibility to evaluate and approve or disapprove permit applications. The Hearing Board must also view the action of the Executive Officer in the context of the greater regulatory program, which in this case is RECLAIM. And since the Executive Officer's action is presumed to be correct, petitioner has the burden by the preponderance of evidence that the Executive Officer did not act properly.

Moreover, because this case hinges over the construction of District Rule 2002(c)(2)(C), we follow the California Supreme Court directive that in construing statutes, "the appropriate mode of review . . . is one in which the judiciary, although taking ultimate responsibility for the construction of the statute, accords great weight and respect to the administrative construction." *Am. Coatings Assn., Inc. v. S. Coast Air Quality Dist.*, 54 Cal. 4th 446, 461 (2012)(citations omitted). In that case, the Court deferred to the District's reasonable construction of the statutory BARCT requirements. *Id.* at 469. Here, TAMCO, while arguing for its construction of Rule 2002(c)(2)(C), did not demonstrate by a preponderance of the evidence that the District's construction was "wrong."

## III. THE EXECUTIVE OFFICER PROPERLY ISSUED TAMCO'S TITLE V PERMIT WITH NO SOx ALLOCATION FOR THE EAF

### A. Rule 2002(c)(2)(C) Need Not Be Construed as a Mandate to Place TAMCO's EAF Into a Pre-existing Table 2 Category

The stated purpose of Rule 2002 is "to establish a methodology for calculating facility allocations ... for Oxides of Nitrogen and Oxides of Sulfur (SOx)." (Rule 2002(a).) Rule 2002(c)(1) sets forth the basic methodology by which starting allocations are to be calculated. Rule 2002(c)(2)(C) further elaborates on this methodology, providing in relevant part, "To determine the applicable emission factor in Table 1 or Table 2, the Executive Officer or designee will categorize the equipment at each facility based on information relative to hours of operation, equipment size, heating capacity, and permit information submitted pursuant to Rule 201 — Permit to Construct, and other relevant parameters as determined by the Executive Officer or designee." TAMCO alleged that this provision creates a mandatory duty on the part of the District to fit SOx-emitting equipment into an existing category on Table 2. (FAP at 10.)

The Executive Officer contended that, while Rule 2002(c)(2)(C) may require categorization of equipment pursuant to an engineering review, the rule allows him to find no "applicable" emission factor if that category does not exist in Table 2. As a result, if there is no applicable emission factor in Table 2, there can be no SOx allocation awarded pursuant to Rule 2002(c)(1).

In reading Rule 2002(c)(2)(C), we agree that by the Rule's own terms it requires the Executive Officer to categorize equipment pursuant to the methodology set forth therein. We further agree that the rule does not, by its terms, require the Executive Officer to place equipment into an existing Table 2 category and use the associated emission factor, if none is found to be "applicable." Petitioner failed to prove by a preponderance of the evidence that this reading of the rule is "wrong." Thus, we conclude that the plain meaning of Rule 2002(c)(2)(C) does not require equipment to be categorized into an existing Table 2 category.

In this case, Mr. Luong testified that District staff conducted the required Rule 2002(c)(2)(C) engineering analysis and determined that TAMCO's EAF did not fit in any existing

category or emission factor on Table 2. (4 Tr. 488-489, 491-492.) Not having the authority to create a new category, the Executive Officer granted no starting SOx allocation to TAMCO's EAF in the Title V permit. This action was "proper" in light of the Executive Officer's reasonable interpretation of the plain language of Rule 2002.

**B. The Executive Officer's Construction of Rule 2002(c)(2)(C) is Consistent with The Purposes and Foundational Requirements of RECLAIM**

We further find that the Executive Officer's construction is consistent with the purposes and foundational requirements of RECLAIM established in Health and Safety Code §§39616(c)(1) and (2). One of the problems of forcibly fitting a piece of equipment into an existing category is that the end result is likely to be that the associated emission factors do not fit, because they are either too high or too low for the equipment at hand. Emission factors are important, because they ensure the RECLAIM program achieves the Legislative mandate reflected in Health and Safety Code §39616(c)(1) and (2) that emission reductions from RECLAIM sources be equivalent or greater than what those sources would have been required to achieve through command-and-control and future air quality measures. In that sense, it would be inconsistent with those requirements to *mandate* the Executive Officer to forcibly fit new equipment into categories with associated emission factors that the new equipment was not originally intended for.

In the present case, TAMCO seeks to be placed into the gray iron cupola category with an ending emission factor of 0.72[10]. Yet this is over 3 times higher than the 0.2 factor TAMCO claims to be the actual emission factor for the EAF (as was claimed in its revised AER, the FAP at 9, and in witness testimony). And while TAMCO argues that District Rule 2002(d)(3) precludes an ending emission allocation greater than its starting allocation, that rule does not affect the comparative analysis (or the result of that analysis) required by Rule 2002(c)(2)(C). In any event, TAMCO ignores the possibility that there may be an applicable control measure to further reduce its ending allocation below the starting allocation. Here, that possibility is real, as Mr. Luong's

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[10] Emission factors stated throughout this Decision are expressed in terms of pounds of SOx per ton of throughput.

testimony demonstrated the applicability of air quality measure A-F-1, which would further reduce TAMCO's ending allocation to at least 20% below its starting allocation.

For these and other reasons expressed earlier, the Governing Board was concerned about the assignment of emission factors. That concern is evident in District Rule 2015. (District Second Request for Administrative Notice (RAN2), Exh. 3.) Rule 2015(a) explains the rule's purpose, which is to specify RECLAIM audit requirements. Thus, extensive annual audits were required to monitor the progress of RECLAIM pursuant to Rule 2015(b) to ensure RECLAIM was continuing to meet its original requirements.

The Governing Board was also aware of certain industry concerns over the accuracy of ending emission factors, and ordered the Executive Officer to re-evaluate them. Rule 2015(c)(3). Significantly for this case, however, the Governing Board mandated only that "the Executive Officer propose amendments to Rule 2002" if he believed it was appropriate. Rule 2015(c)(3)(A) (emphasis added). The Executive Officer was given the authority to recalculate allocations only "if amendments are adopted . . . ," and was then required to offset any adjustments to allocations "in the AQMP." *Ibid.* Clearly, had the Governing Board been solely concerned about the accuracy of these emission factors, it could have easily instructed the Executive Officer to immediately implement the new emission factors. It did not. The fact that it did not reveals an equal concern by the Governing Board that it maintain control over the list of categories and associated emission factors.

Thus, we do not find the Executive Officer's construction – that there could be a finding of "no applicable emission factor in Table 2" – to be in error. The end result is that only the Governing Board has the power to amend Table 2 to include the EAF category and its associated emission factor. Indeed, this construction is consistent with the Governing Board's intent expressed in Rule 2015, a part of the RECLAIM program.

Having found no mandate in Rule 2002(c)(2)(C) to fit equipment into a pre-existing Table 2 category, we could end our Decision here. However, we will go on to address TAMCO's claim

that its EAF should be fitted within the gray iron cupola category in Table 2, as our response further exemplifies why the Executive Officer's construction was not "wrong."

### C. The EAF Does Not Fit Within the Gray Iron Cupola or Miscellaneous Categories of Table 2

In its First Amended Petition, TAMCO originally alleged that its EAF could have (and thus should have) been placed within the existing category of gray iron cupola or one of the two existing "miscellaneous" categories of Table 2. Initially, we note that Mr. Luong's testimony demonstrated that to do a proper Rule 2002(c)(2)(C) comparative analysis, an engineer needs to examine the engineering parameters for both the equipment and the Table 2 source. (4 Tr. 487-489, 491-492.) There is no evidence indicating that TAMCO examined the engineering parameters defining the gray iron cupola category or miscellaneous categories. TAMCO did not submit to this Hearing Board a proper Rule 2002(c)(2)(C) engineering comparative analysis between TAMCO's EAF and the Table 2 existing categories of gray iron cupola or miscellaneous. And, in fact, TAMCO's witnesses testified that no such analyses were prepared by TAMCO for its EAF. (2 Tr. 183-84; 3 Tr. 293.) Consequently, this Hearing Board finds that TAMCO has not conducted or submitted the requisite Rule 2002(c)(2)(C) comparative engineering analysis to categorize TAMCO's EAF as a gray iron cupola or miscellaneous.

Conversely, Mr. Luong testified that the District engineering staff conducted a Rule 2002(c)(2)(C) analysis for TAMCO's EAF and concluded that it was a unique piece of equipment to be categorized as an EAF as it had been categorized for Table 1. (4 Tr. 487.) Mr. Luong also explained why TAMCO's EAF could not fit within the pre-existing Table 2 gray iron cupola category. (4 Tr. 488-489, 491-492.) Moreover, the ending emission factor for the gray iron cupola is 0.72, more than 3 times the 0.2 factor claimed by TAMCO for its EAF. And as testified to by Mr. Luong, that substantial difference is an indicator demonstrating that the results of the District's Rule 2002(c)(2)(C) analysis is correct – that the EAF does not fit within the gray iron cupola category. (4 Tr. 492.)

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Mr. Luong's testimony further highlights the error in relying solely on the descriptive words in Table 2 to conduct a comparative Rule 2002(c)(2)(C) analysis. Yet, TAMCO claims that its EAF should be classified in the gray iron cupola category merely because Table 2 lists the gray iron cupola under the heading "Fuel" along with "Iron/Steel Foundry" as the basic equipment. Despite these contentions and labels, "Iron/Steel Foundry" is plainly not "equipment." As with the basic equipment category of "Miscellaneous" (discussed further below), Rule 2002(c)(2)(C) does not end the comparative analysis with simply the descriptive terms of Table 2. Rather, the District must look at the engineering parameters for both the equipment and the Table 2 category to determine whether there is a fit.

TAMCO's new argument made on page 10 of its closing brief that even Table 2's words describing a gray iron cupola should be disregarded as "simply examples" is similarly unpersuasive. Table 2 broadly lists other industries as "Basic Equipment" with the actual equipment under the "Fuel" heading. For example, Table 2 also lists the secondary lead industry as basic equipment with the associated "Fuel" as the "Reverberatory Smelting Furnace." Rule 2002(c)(2)(C) simply does not require the Executive Officer to ignore the "Fuel" heading in Table 2, and rely solely the basic equipment listing.

As noted earlier, TAMCO failed to pursue in its Reply Brief, Closing Brief, or closing statement its claim that the EAF should be fitted within Table 2's category of miscellaneous, and thus it could be considered waived. Nevertheless, TAMCO failed to prove that its EAF fits within either of these two categories. And while the EAF is arguably encompassed by the broad category of miscellaneous, Mr. Luong testified that to do a Rule 2002(c)(2)(C) comparative analysis, he had to research the origin of this miscellaneous category, particularly since Table 2 lists two miscellaneous categories. In that research, he learned that the two miscellaneous categories involved a "silicate melting furnace" and a "tail gas treating unit in a refinery." (4 Tr. 490.) Thus, he concluded that TAMCO's EAF is a completely different operation than described by these two miscellaneous categories. *Ibid.*

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TAMCO did not challenge Mr. Luong's testimony that the District's Rule 2002(c)(2)(C) analyses did not result in fitting TAMCO's EAF into any of the categories sought by TAMCO. As a result, we find that TAMCO's EAF does not fit within the categories of gray iron cupola or miscellaneous. Regardless, we are constrained by our standard of review and could not, in any event, substitute our judgment for that of the District or its Executive Officer.

**D. There is No Long-Standing Practice or Interpretation to Fit Equipment Into Tables 1 or 2 that the District Determines Cannot be Fit Under A Rule 2002(c)(2)(C) Analysis**

TAMCO further argued that the District has an alleged long-standing practice to fit all equipment into Tables 1 or 2 regardless of the result of any Rule 2002 (c)(2)(C) analysis. As explained above, the District spent hundreds of hours developing emission factors for all equipment reported in the AERs, including sending notices to facilities and discussing allocations with many of them. As such, it would not be atypical for the District to fit virtually all of the equipment in specified categories.[11] Nevertheless, there were a number of examples raised by TAMCO's witnesses of equipment that was added to Table 2 or reclassified after the start of RECLAIM. These examples all occurred within the first few years of the start of the RECLAIM program, however, and in our opinion did not establish a "long-standing practice" that applies to already-existing equipment added to RECLAIM 20 years after its inception.

Moreover, contrary to TAMCO's claim of a long-standing practice, the District did go to the Governing Board in July 1996, shortly after RECLAIM was adopted to add a new category of equipment to Table 1, the delacquering furnace. (2 Tr. 193, 242.) In that case, after concerns were raised by the facility, the District performed another Rule 2002(c)(2)(C) analysis and determined that no existing category in Table 1 fit that equipment. As a result, the Executive Officer went to

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[11] TAMCO's claim that the District had never issued zero allocations for emitting equipment is belied by TAMCO's own witness. As testified to by Mr. Hower, there was at least one somewhat similar instance in the case of Lunday Thagard, where the District issued no RECLAIM SOx allocations. (2 Tr. 259.) As a result, Lunday Thagard needs to purchase about 40,000 pounds of SOx credits per year. (3 Tr. 312-13.)

the Governing Board to add a new category for delacquering furnaces, because "[t]here is no equipment category in Table 1 of Rule 2002 for delacquering furnaces." (Coy Supp. Decl., at Exh. P, p.3.) If anything, this supports the District's interpretation of Rule 2002 that there is no mandate to fit equipment within a category on Table 1 or 2 if none fits.

TAMCO attempts to dismiss the outcome of the second Rule 2002(c)(2)(C) analysis by arguing that the initial Rule 2002(c)(2)(C) analysis, albeit incorrect, nevertheless resulted in some starting allocation for the delacquering furnace. However, taking TAMCO's logic further, TAMCO appears to argue that the alleged Rule 2002(c)(2)(C) mandate may easily be fulfilled by an incorrect result.[12] However, we are uncomfortable in finding a mandate that is so easily fulfilled by an erroneous result, and we decline to do so. Indeed, a practice of fitting equipment into the categories of the Tables regardless of its fit according to a Rule 2002(c)(2)(C) analysis would essentially eviscerate that requirement. As a result, we find no long-standing practice to fit equipment into Tables 1 or 2 regardless of the Rule 2002(c)(2)(C) analysis.

Even if there were a long-standing practice, which we do not find here, courts have acknowledged that "'[a]n administrative agency is not disqualified from changing its mind . . .'" *Californians for Political Reform Found. v. Fair Political Practices Comm'n.*, 61 Cal. App. 4th 472, 488 (1998)(citations omitted.) We recognized this principle, that the District may change its policies, in the dairies case. (D. Exh. 24, at p. 24) Thus, the disputed existence of a long-standing practice is irrelevant to our decision.

## CONCLUSION

TAMCO failed to meet its burden of proof by a preponderance of evidence that Rule 2002(c)(2)(C) mandates the Executive Officer to fit equipment into an existing category of Tables 1 or 2 regardless of the results of a Rule 2002(c)(2)(C) comparative engineering analysis. In this case, we defer to the Executive Officer's construction of Rule 2002(c)(2)(C), as is proper pursuant

[12] We note some tension between TAMCO's logic and the case of its billet reheat furnace, which had also been initially improperly categorized. Under TAMCO's logic, the Executive Officer would have fulfilled his mandate and there would be no recourse to changing the categorization.

to the California Supreme Court's ruling in *Am. Coatings Assn., Inc. v. S. Coast Air Quality Dist.*, 54 Cal. 4th 446, 461 (2012). And as a result, the Hearing Board finds that the Executive Officer properly issued TAMCO's Title V renewal permit with no SOx allocations for TAMCO's EAF.

**BOARD MEMBER:** Julie Frusetta, Vice Chair

**DATED:** Sept. 25, 2014

**I VOTE NO:** David Holtzman 9/25/2014

**I VOTE NO:** Robert F. Wayne, M.D., Alternate Member 9/26/2014

Attachment: Dissent

Dissent

A facility in the RECLAIM program gets a starting allocation of emission credits based on its rate of emissions at the start of the program. That is how the program is structured. That is the clear letter and intent of the program's rules.

The program's rules do not provide for giving a facility no starting allocation (or a starting allocation of zero) if both agency staff and the facility's owners or operators failed at the outset of the program to discover or properly quantify certain emissions of sulfur oxides (SOx). The program's rules make no provision for treating a longstanding and long-operating facility's new owners, who discover and duly report ongoing emissions, as if they had just opened an entirely new facility in the area, and as people required to make large cash payments.

Regarding South Coast Air Quality Management District Rule 2002, as amended November 5, 2010, I have come to the following conclusion:

**Rule 2002`s use of the words "the applicable starting emission factor" — without any hedging or limiting words such as "if any" — in Rule 2002(c)(1) and in Rule 2002(c)(2)(C) means that for every facility in the SOx part of the RECLAIM program there is an applicable starting emission factor in Table 2 of the rule ("RECLAIM SOx Emission Factors"). The rule does not allow the Respondent's "Executive Officer" (Rule 2002(c)(1)) or "Executive Officer or designee" (Rule 2002(c)(2)(A) thru (C)) to act otherwise. Since, in issuing the permit at issue in this matter, the Executive Officer (or designee) did act otherwise, the Executive Officer (or designee) acted improperly in issuing the permit at issue in this matter. Thus, the Hearing Board should have granted the Petitioner's appeal.**

I am constrained in what I am writing in this dissent because a Hearing Board dissent is supposed to reflect only what was said in the hearing and deliberations on the matter at hand. I believe I expressed the thoughts above and below about the merits of the case during the proceedings, although not in precisely the same words.

I said on closing argument/deliberation day (note: transcripts and recordings of all proceedings are available) that I was surprised anyone could rule in this case that the Respondent's employees had properly implemented the rule. I was so surprised that I was not prepared to read into the record (to lay the groundwork for a written dissent) many of the reasons I could think of that the points raised in opposition to the appeal were wrong! (Before that day, I had the sense that the Hearing Board would vote to grant

the appeal. If the Board had granted the appeal, it could have used the Petitioner's pleadings for reasons why. Or, it could have asked the Petitioner to prepare a document to help it memorialize findings [as it eventually did with the Respondent].)

I did say I agreed with pretty much everything except for one thing in the Petitioner's closing brief. (Transcript page [Tr.] 712.) I shall not detail all the reasons I think denial of the appeal was wrong, since I did not state them all on the record. Instead I will highlight below some of the back-and-forth I remember from the Hearing Board's deliberations.

My colleagues focused on different things during the deliberation.

One said she was thinking of "If it doesn't fit, you must acquit," the infamous assertion from O.J. Simpson's criminal trial on murder charges. So she couldn't bring herself to find that the District's Executive Officer has not acted properly. I took issue in some way with using that standard, but did not pursue the matter in great detail.

She was also concerned that giving emission credits to the operators of the facility at issue might place the RECLAIM program out of compliance with a mandate from a different level of government, and she thought the program rules wouldn't have been written to allow that. I said that I did not think the District would be prejudiced in such a way if the Hearing Board granted the appeal in this case. (Tr. 768.) In questioning during the hearing, I sought but did not find evidence of any specific threat from another agency that the District would face if the Hearing Board granted the appeal.

Another colleague was concerned with the last column of Rule 2002's Table 2, although that column was not directly at issue in this case. Specifically, he was concerned that a number in that column on one of the rows might result in the Petitioner being entitled to receive a windfall of sorts of SOx emission credits. But I pointed out that Petitioner had no intention to accept such a windfall, and recalled that a portion of Rule 2002 (Rule 2002(d)(3)) would prevent such a windfall.

I also pointed out that the District's Governing Board could still amend the rule to address my colleague's concern if it wished. My colleague appeared to be of the mind, however, that it seemed too late for the Governing Board to do that, since the program was no longer new, and he said the only changes made to date came when the program was new. I protested that the the SOx portion of the program was new with regard to the facility at issue, but my protest was to no avail. My colleague was not swayed.

During lunchtime on closing argument/deliberation day, another colleague found some language in the hearing transcripts that gave her pause. After lunch, she was eager to know whether the facility's amended annual emission report (AER) for an early program year had been approved by the District (Respondent). (Tr. 761.) (The Petitioner filed the amended AER to disclose what were, at the time, newly-discovered SOx emissions.) Told the amended AER had not yet been approved, she expressed unwillingness to base her decision on it, citing a need to give deference to the District's Executive officer. (Tr. 762.)

About the amended AER, I had argued, however, that the District had sat on its hands for so long without taking any action that a form of laches could apply, and the Board could (and I did) consider the District (by its inaction) to have approved the amended AER. (Tr. 710-711.) I may not have made this point well enough, however.

I am sorry that the Hearing Board's deliberation was so brief.

But I think I made my basic point that I was surprised that anybody could read the rule at issue in a way that allows the Respondent's Executive Officer to refuse place a facility subject to the rule in one of the rule's categories. (To be fully precise, it is a facility's relevant operations [emission sources or process units], rather than the facility itself, that the District must categorize.)

The rule's Table 2 provides a starting emission factor for each category.

This case was really very simple from the start: To implement its own rule, the District must place the relevant operations of the facilities in the SOx part of the RECLAIM program into categories in a table that lists starting emission factors. Using "the applicable starting emission factor" (or for multiple operations, multiple factors), each facility in the RECLAIM program must get a starting allocation of emission credits based on its rate of emissions at the start of the program. That has not yet happened for TAMCO. The Hearing Board should have granted TAMCO's appeal.

For such reasons, I dissent.

- David Holtzman
Public Member