
South Coast
AQMD
South Coast
Air Quality Management District


Our Mission Statement
“The South Coast AQMD believes all residents have a right to live and work in an environment of clean air and is committed to undertaking all necessary steps to protect public health from air pollution with sensitivity to the impacts of its actions on the community and businesses.”
South Coast
AQMD

# The *Basics* of the SCAQMD

**SCAQMD Staff** - Approximately 800 employees; including scientists, planners, engineers, and inspectors.

**SCAQMD** continuously monitors air quality at **36** locations throughout the four-county area. The test of whether the rules, permits and inspections are working is the quality of the air we breathe. This also allows AQMD to notify the public whenever air quality is unhealthful.

# How SCAQMD Began

**People living in San Bernardino and Riverside counties wanted a better approach to fighting air pollution. So a regional approach, the SCAQMD, was created in 1977.**


# What is South Coast AQMD?


***We are the regional government agency tasked with achieving federal clean air standards in order to protect public health in Southern California.***

**Includes 4 Counties – over 10,000 square miles**

**Home to nearly 17 million people (over 40% of the State's population) and over 12 million vehicles.**

## SCAQMD's Roles

- **Control stationary and area sources within the South Coast Basin**
- **Research new technology and develop new ideas to help clean the air we all breathe**
- **Spread awareness of the dangers associated with poor air quality**

# *WHO WE ARE*

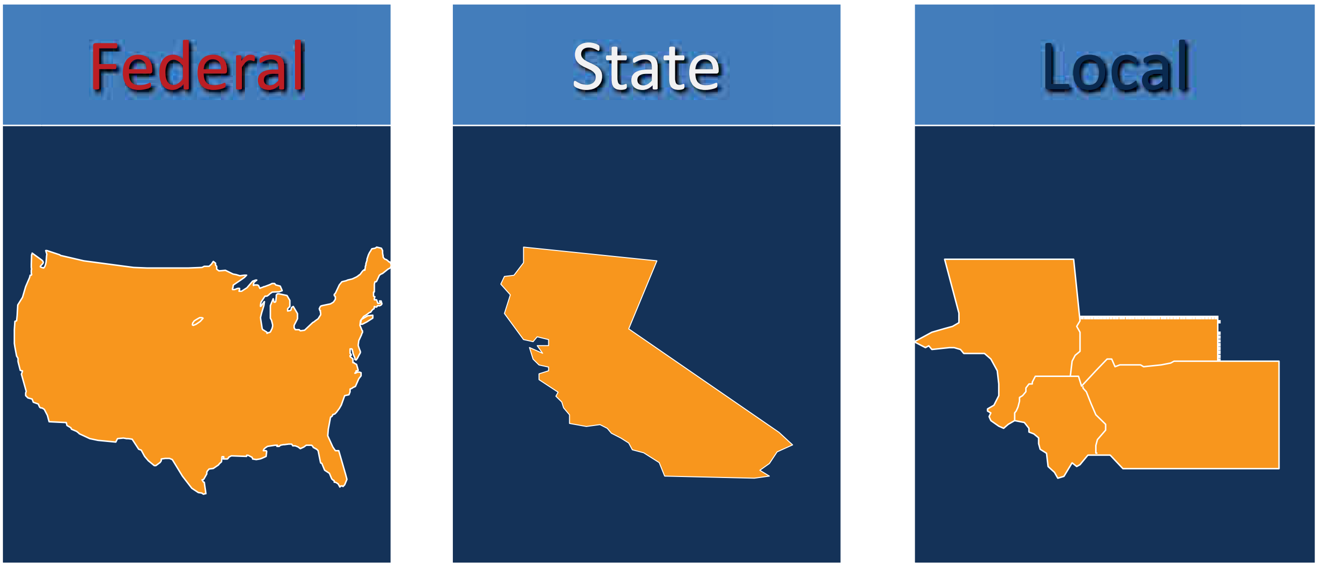
## *South Coast Air Quality Management District*

Our Regional Population Ranks Above the State of Illinois.
Just Under the State of Florida…

| Ranking | State | Population |
|---|---|---|
| 1 | California | 37,253,956 |
| 2 | Texas | 25,145,561 |
| 3 | New York | 19,5378,102 |
| 4 | Florida | 18,801,310 |
| 5 | Illinois | 12,830,632 |
| 6 | Pennsylvania | 12,702,379 |
| 7 | Ohio | 11,536,504 |
| 8 | Georgia | 9,687,653 |
| 9 | Michigan | 9,883,640 |
| 10 | North Carolina | 9,535,483 |


South Coast AQMD

# United States Air Quality
## Regulatory Framework




# Air Quality Regulatory Framework

- **Federal - U.S. Environmental Protection Agency**
  – Establishes national ambient air quality standards
  – Oversees State Air Programs
  – Regulates Mobile Sources (On-Road & Off-Road)
  – Establishes Stationary Source Standards

- **State - California Air Resources Board**
  – Establishes state ambient air quality standards
  – Regulates most mobile sources (On-Road)
  – Establishes Toxics Standards

- **Local - South Coast AQMD**
  – Monitors and forecast air quality standards
  – Adopts local rules and regulations
  – Implements state and federal requirements
  – Regulates Stationary Sources

# WHERE WE STAND TODAY

## GOOD NEWS

- Our air quality is improving.
- Stationary Sources controlled upwards of **94%**
- California has **NO** coal-burning power plants, which spew the most pollution.
- By 2020, **33%** of the electricity used statewide will be required to come from wind, solar, geothermal or other renewable resource.

## BAD NEWS

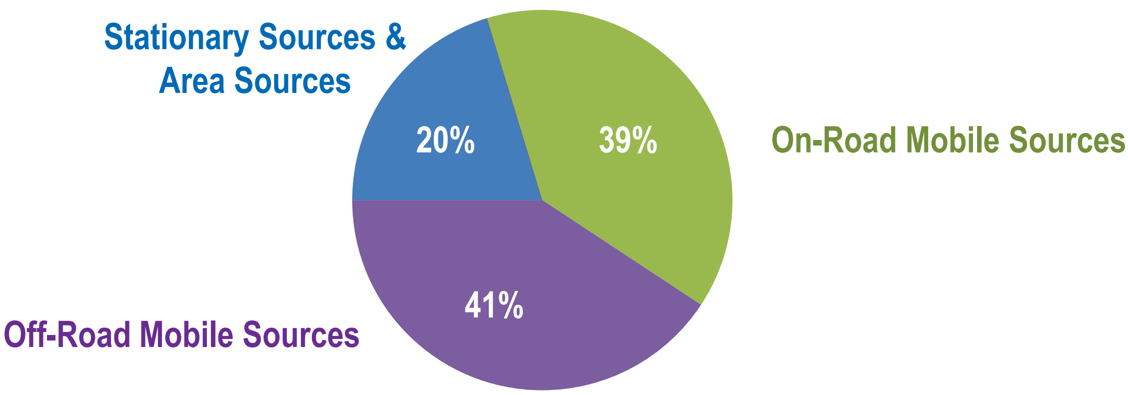
- Air quality is still worst in the nation ($O_3$ + PM 2.5)
- Overall carcinogenic risk among the highest in the nation.

## MOST DAUNTING CHALLENGES

- We must reduce PM2.5 and NOx from mobile sources to meet federal health-based standards
- But we do not have authority to regulate most mobile sources.



# Mobile Sources Cause 80% of Air Pollution In South Coast Region




**Pollutants: NOx, SOx, PM2.5**

**SOURCES**

**Stationary** = refineries, power plants, gas stations

**Area** = road dust, paints and other consumer products

**On-Road Mobile** = cars, buses, trucks

**Off-Road Mobile** = ships, planes, trains, construction equipment

# Range of Facilities Regulated

Automotive Painting

Gas Station


Dry Cleaner

Hospital

Refinery

Power Plant



# Key Air Pollutants

South Coast AQMD

- **Particulates** (PM$_{10}$ & PM$_{2.5}$)
  - Form from emissions of nitrogen oxides, sulfur oxides, and direct particulates
- **Ozone** ("Smog")
  - Forms from emissions of nitrogen oxides and hydrocarbons
- **Air Toxics**
  (e.g. Diesel Exhaust)
  - Greatest impacts near highways, railyards, ports

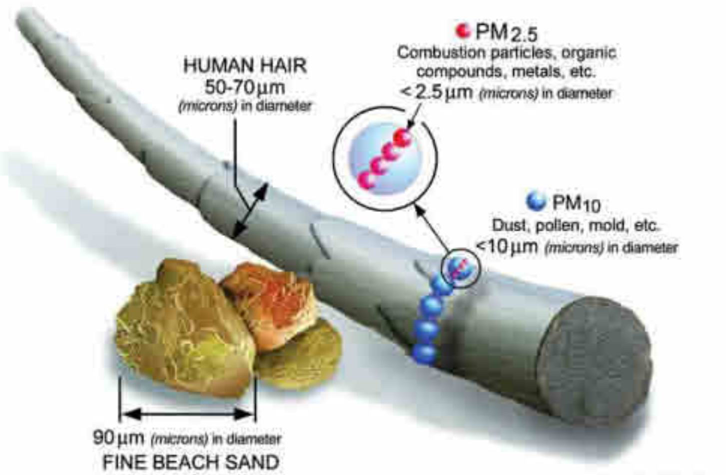
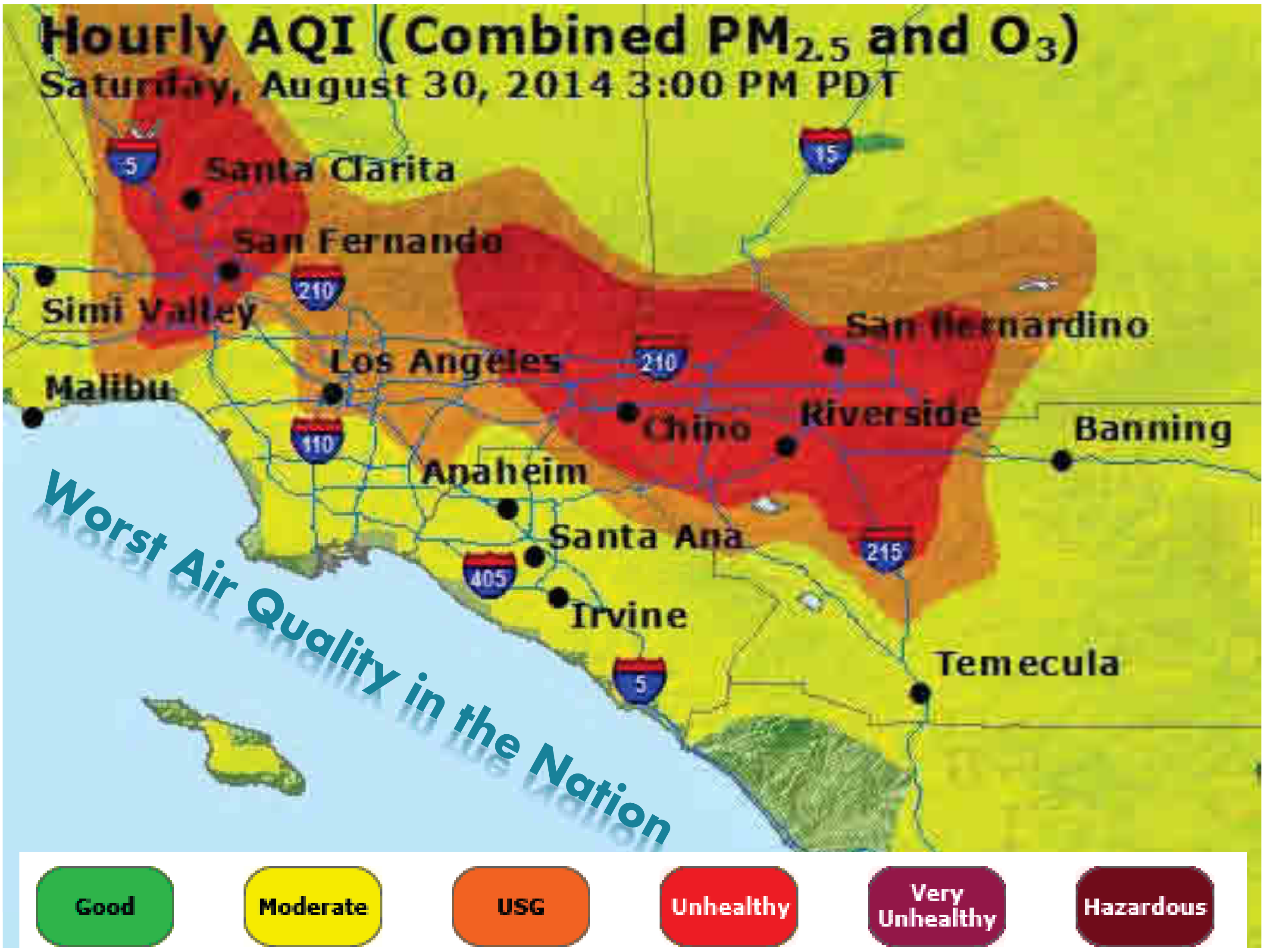
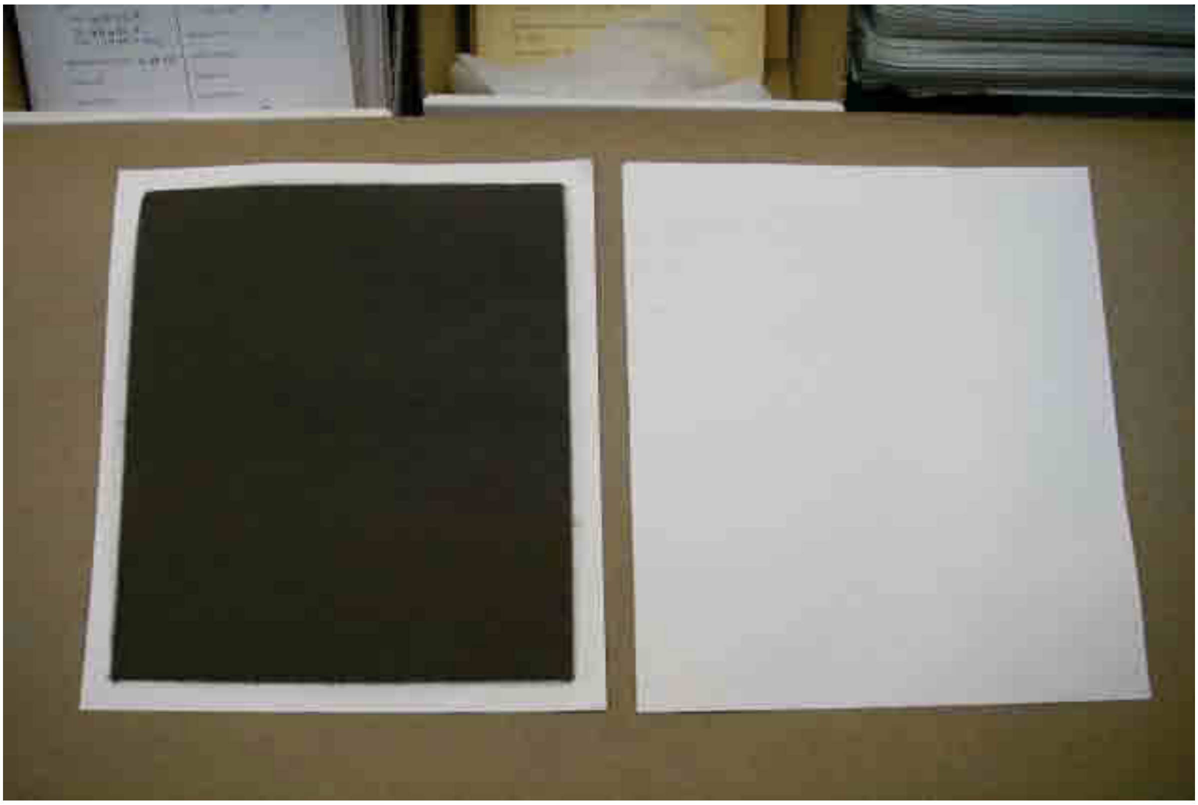



Image courtesy of the U.S. EPA




# Breathing Soot

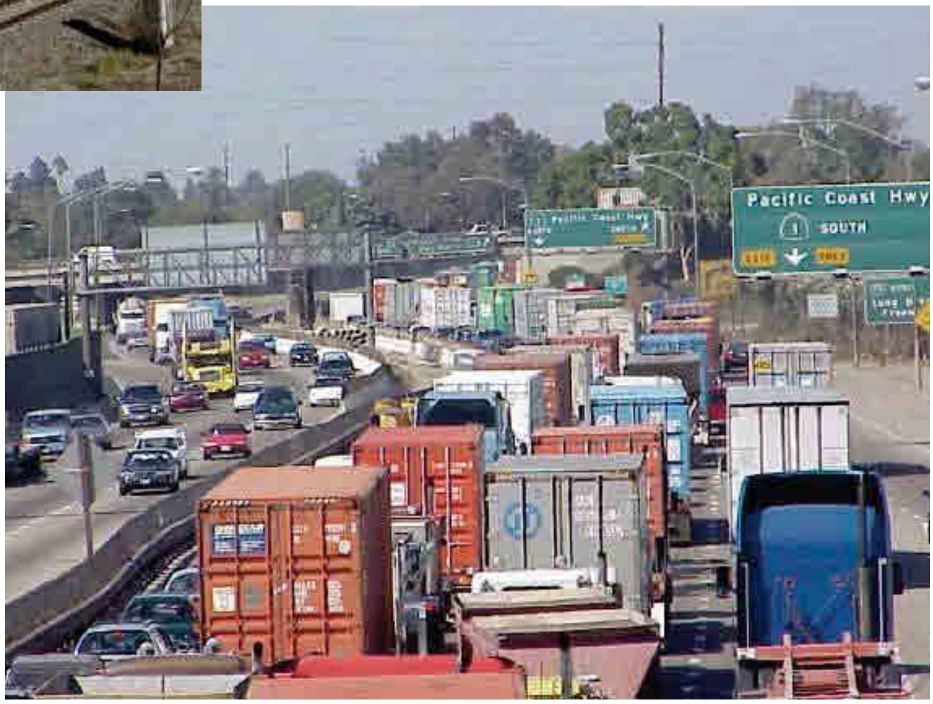


## Ports of Los Angeles and Long Beach

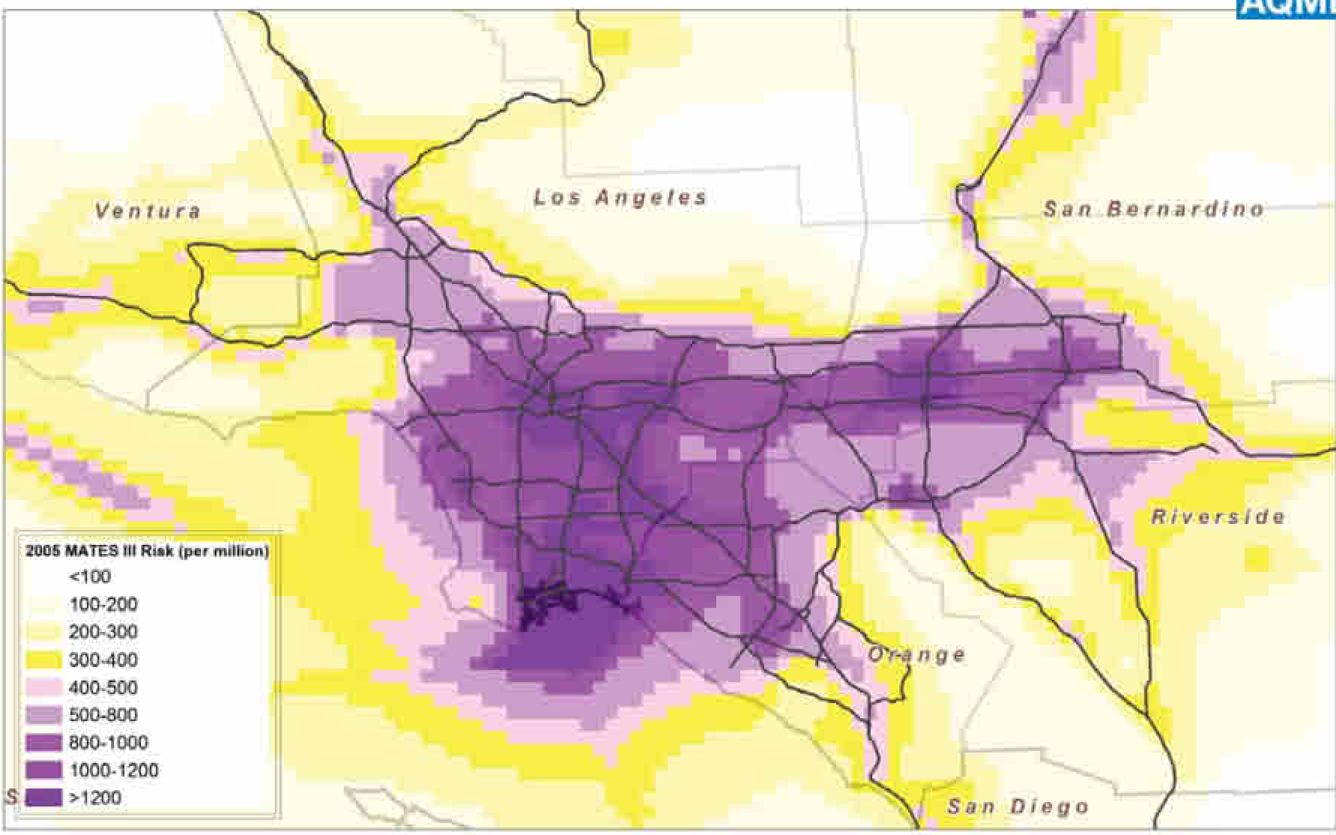
- Nation's highest volume container cargo port complex
- Majority of imported containers destined out of Southern California
- >40 % of nation's containerized imports arrive here
- Cargo tripled in recent years and will double in next decade

South Coast AQMD

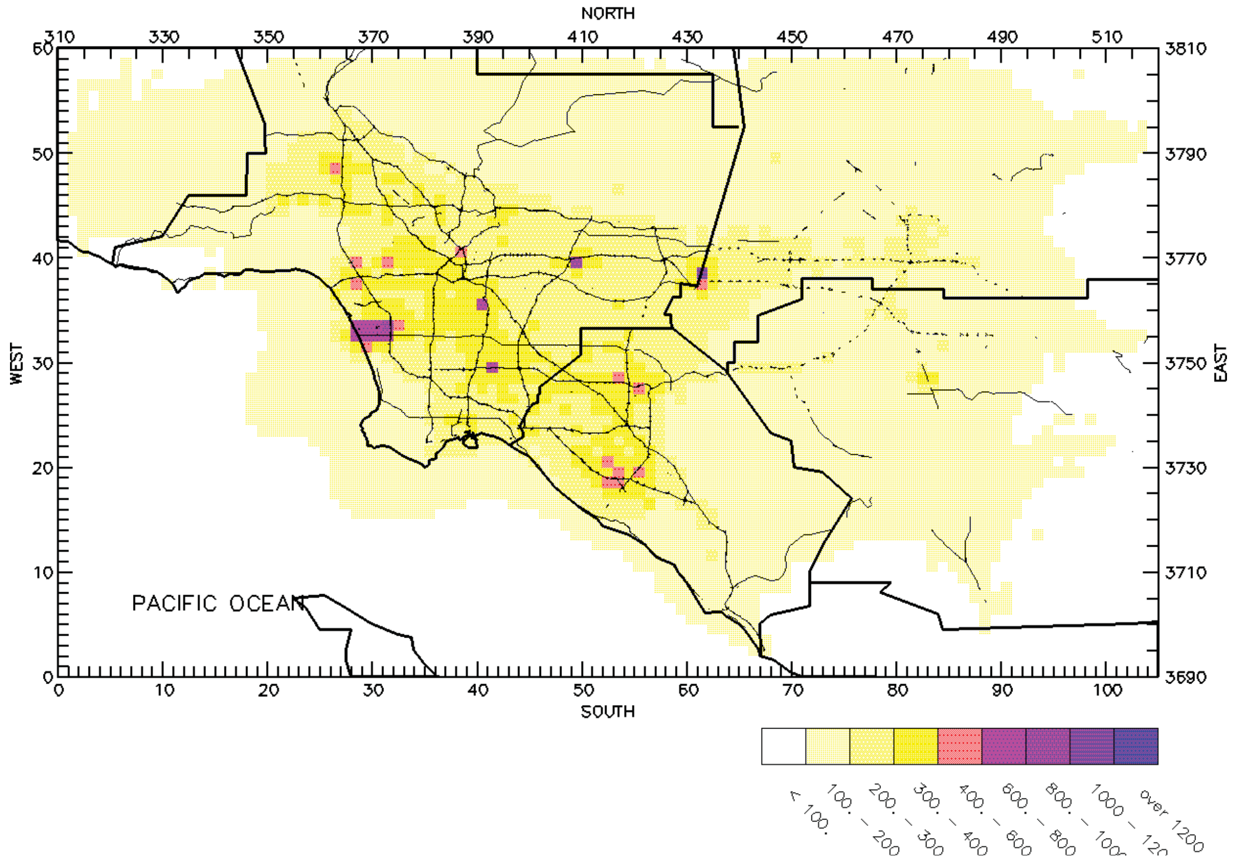
South Coast AQMD



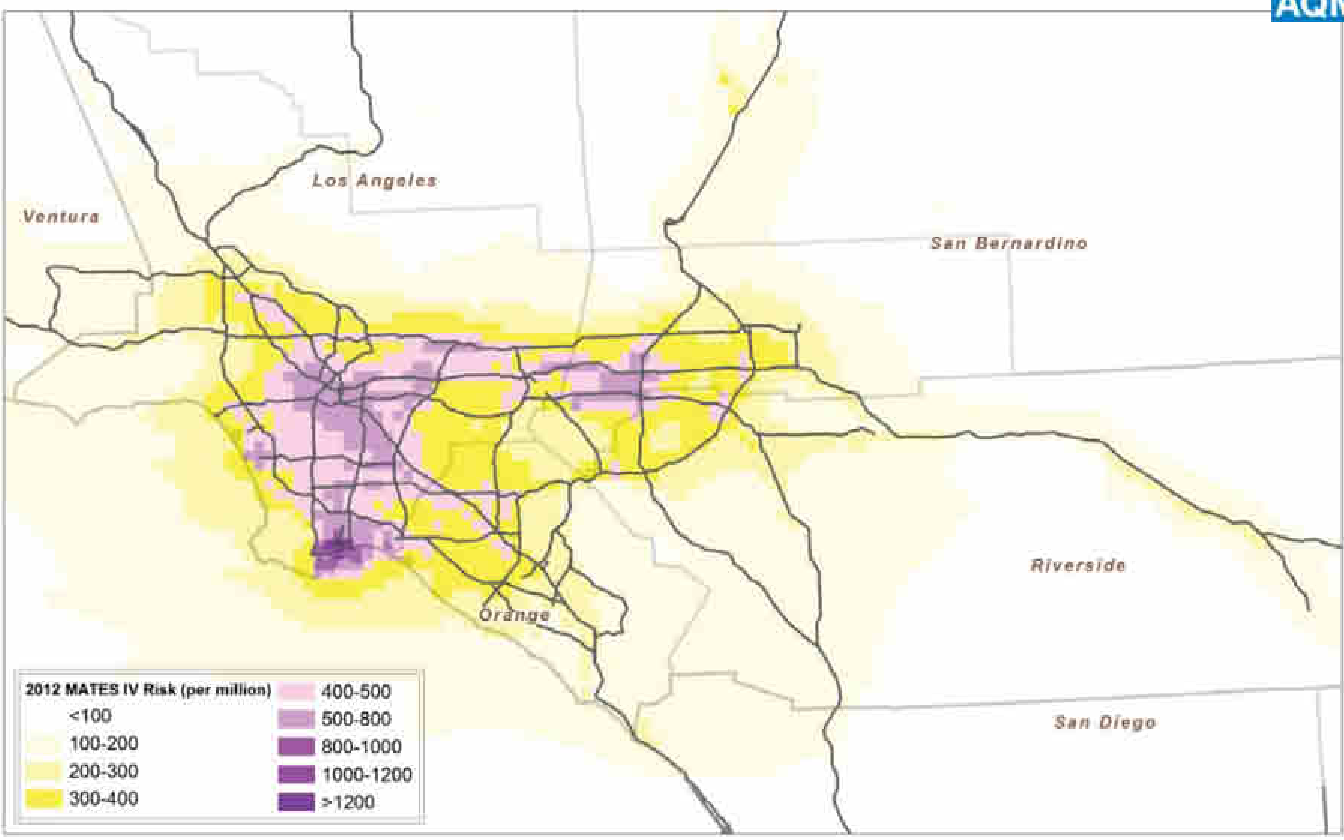

# MATES-III (2005)
# Modeled Air Toxics Risk



# MATES-III Modeled Cancer Risk Excluding Diesel Sources




# MATES-IV (2012) Modeled Air Toxics Risk



# The Solution? Cleaner Technologies

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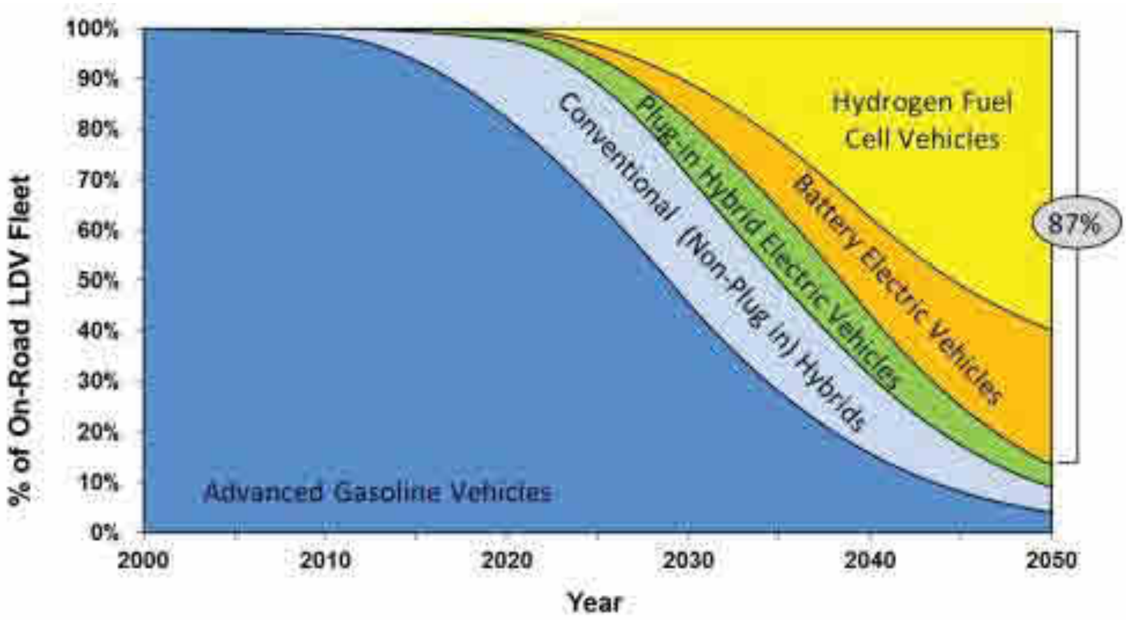
# Seeing into the Future




Source: CA Air Resources Board

# Plug-in Electric Vehicles Available Now


# Plug-in Electric Vehicle Basics

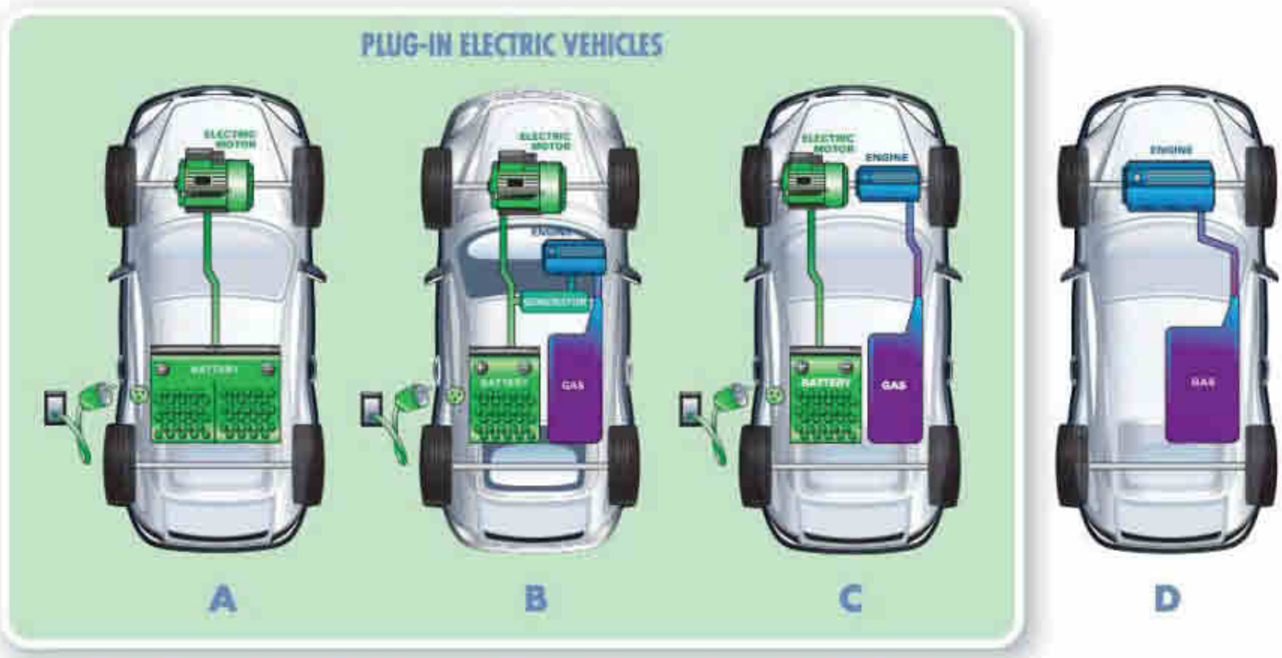



**Figure 2.** *A comparison of PEV and conventional vehicle configurations. (A) battery electric vehicle, (B) series plug-in hybrid electric vehicle, (C) parallel plug-in hybrid electric vehicle, and (D) conventional internal combustion engine vehicle. (Courtesy Southern California Edison)*

# Fuel Cell Technology

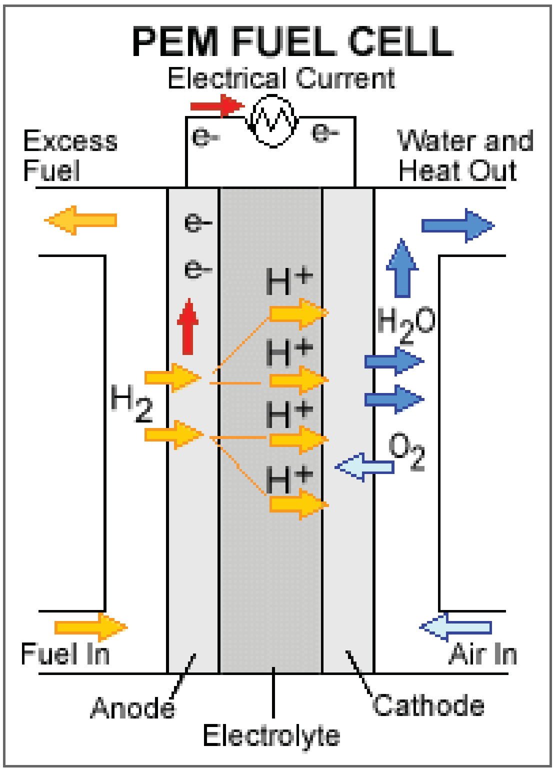
**Proton Exchange Membrane (PEM)**

**Fuel:** hydrogen ($H_2$)

**Exhaust:** water ($H_2O$)

Does not burn the $H_2$; zero tailpipe emissions.

**Other types of fuel cells may have emissions.**



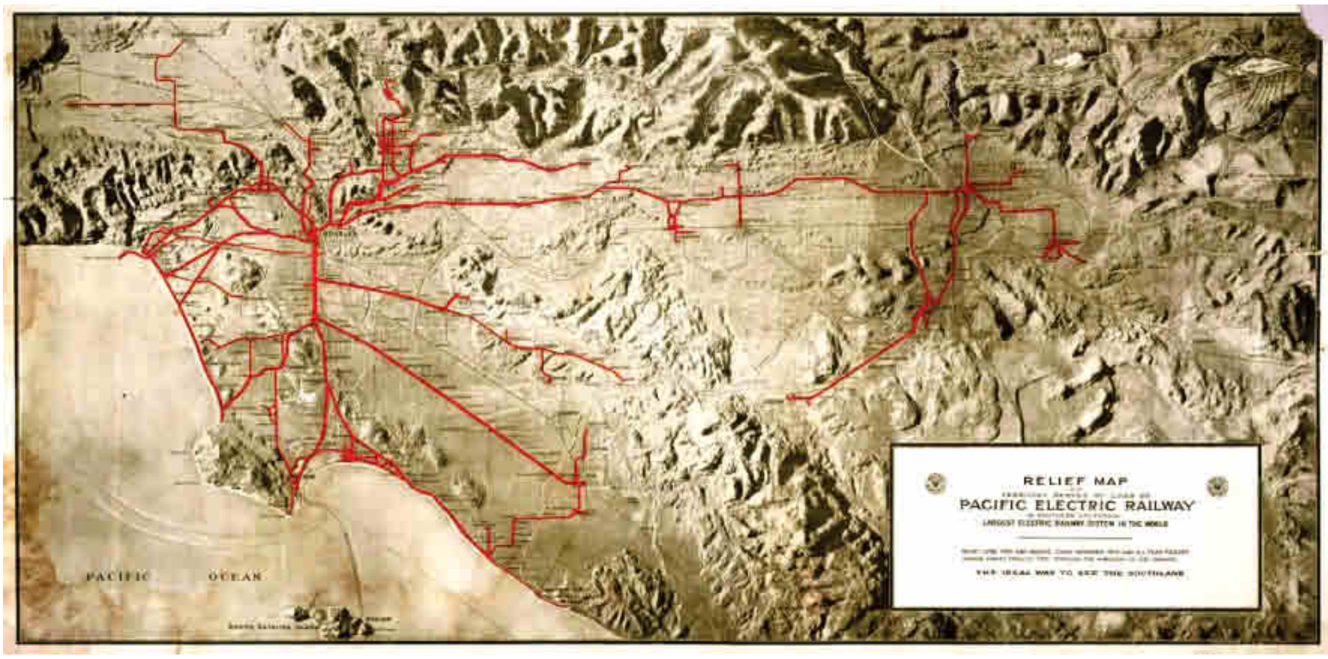

# 100 Years Ago: Electric Local Rail Transit

South Coast AQMD


**Los Angeles Pacific Electric Railway Depot, circa 1910**

# 1944:
# Electric Regional Rail Transit

**Four Counties** **1,150 Track Miles** **900 Cars** **109 Million Passengers**

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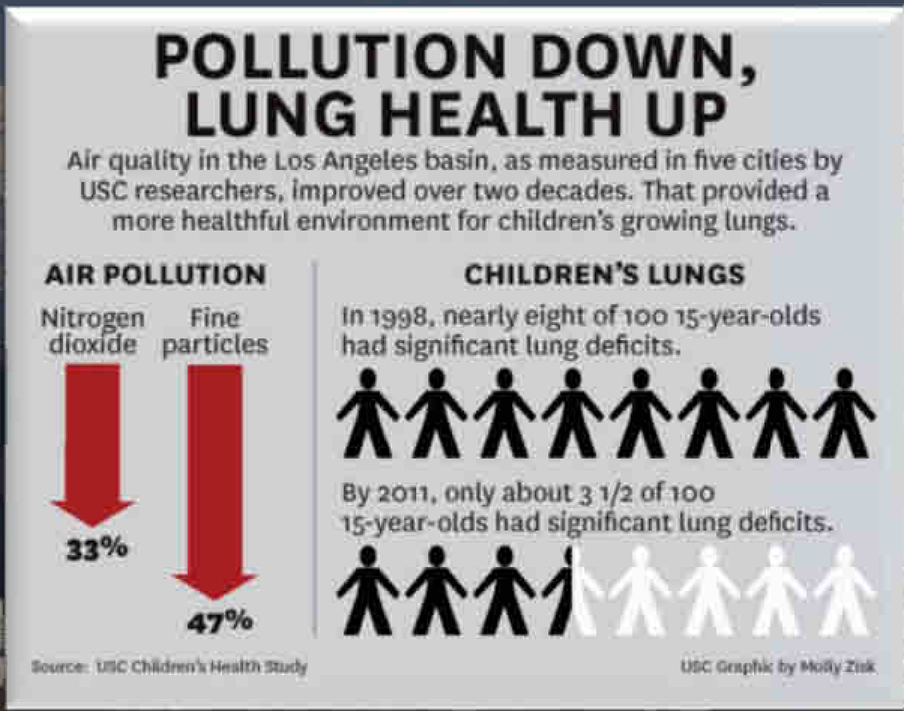
# 40 Years Later Our Air is Better

- Last 30 Years: Population, productivity, employment and jobs have increased, while pollution levels have fallen.
- 20-year USC study followed children from throughout region.
- Study found Millennials in Southern California breathe easier than Gen-Xers who came of age in the '90s.




## Looking Ahead…

# AIR QUALITY COMPLIANCE

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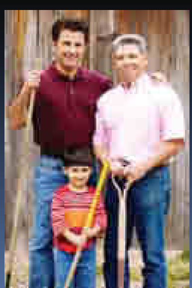
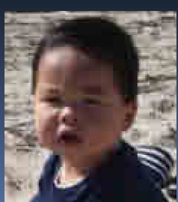
# SCAQMD Mission



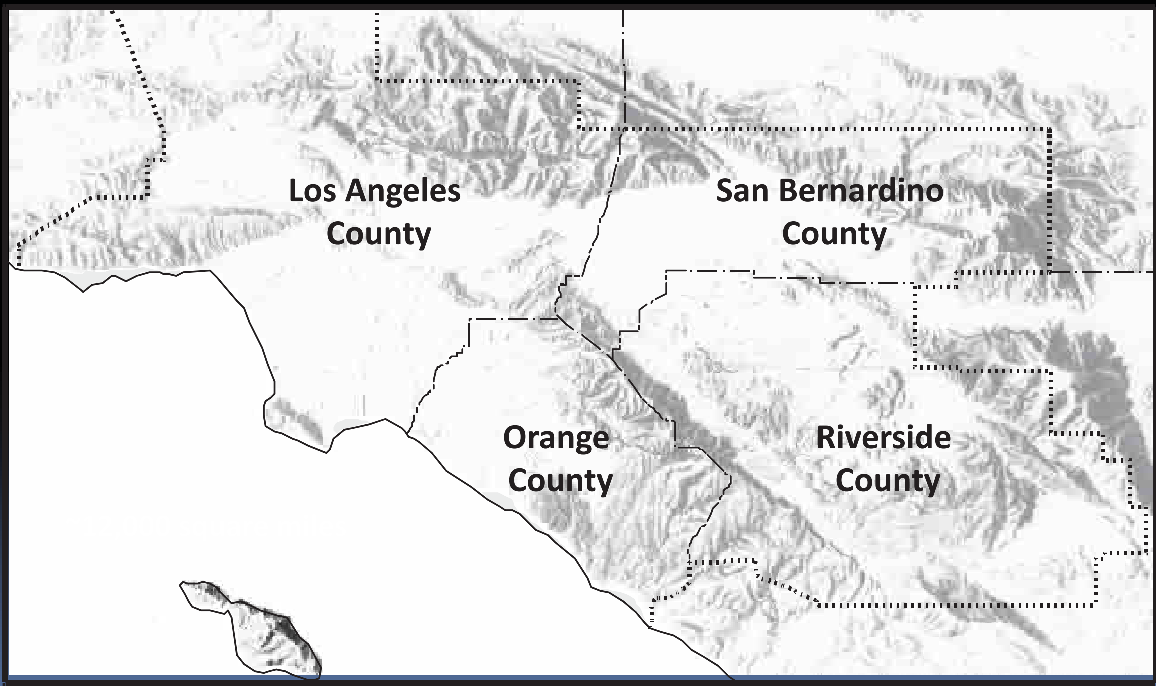


To achieve and maintain healthful air quality for all who live and work in our region




# SCAQMD Jurisdiction




# 60,000+ permits held by 27,000+ facilities

- Service stations, dry cleaners, autobody shops, other neighborhood commercial operations
- Refineries, power plants, aerospace, RECLAIM, Title V facilities

## Compliance Organization

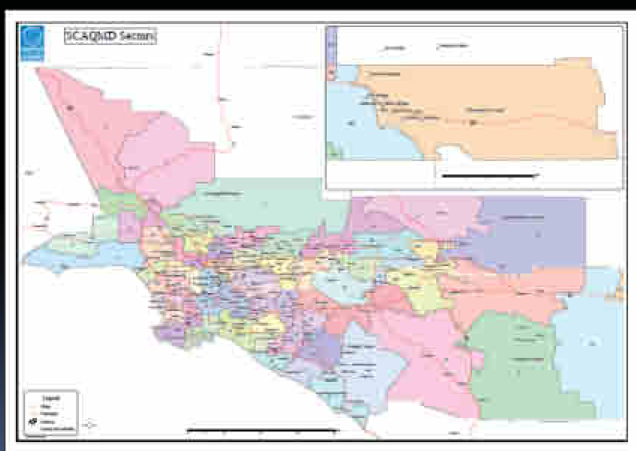
- By source type
  - Refineries & power plants; toxics & waste management facilities
  - Retail gasoline dispensing facilities
- By community (geographic sectors)
  - Industrial facilities & neighborhood commercial operations

## Community-Based Deployment

Sector inspectors

- Conduct general industrial facility inspections
- Respond to local community complaints

**Familiarity with local community helps expedite identification of emission sources**



**~12,000 square miles**

# Compliance Program Goals

- Ensuring businesses comply with applicable regulatory requirements
  - Holding all companies to the same regulatory standards applicable to their industry ensures a level playing field
    - Conducting timely compliance determinations
    - Ensuring prompt resolution of noncompliance
    - Providing consistent, fair field enforcement policy & practice for all

# Compliance Program Goals

- Resolving air quality problems
  - Ensuring community access to SCAQMD for complaint resolution
  - Investigating air quality complaints and resolving instances of noncompliance

# Field Staff Support

- Ongoing technical training enhances field staff experience and capabilities
- Assigned SCAQMD vehicles provide visible reminder of field presence and facilitate timely staff deployment
- Smart phones facilitate inspector communication with:
  - Source representatives
  - Members of the public
  - SCAQMD supervisors and staff
- Laptop computers provide remote access to central database and website, reducing time spent in office
- Automated complaint hotline notifies supervisors of off-hours complaints

# Compliance Policy & Practice

Consistent, fair field enforcement

- Notices to Comply issued for minor noncompliance
- Notices of Violation issued for emissions-based noncompliance
- Variances and Orders for Abatement sought for ongoing noncompliance
- Violations evaluated individually to ensure appropriate assessment of civil penalties

## Compliance Program Features

- Periodic Inspections & Audits
- Complaint Response & Resolution
- Surveillance & Special Projects
- Hearing Board Support
- Source Education & Outreach
- Emergency Response Assistance

## Periodic Inspections & Audits

- Inspections
  - Equipment Lists
  - Title V
  - New Businesses
- Audits
  - RECLAIM
  - QA/QC

## Inspection & Audit Frequency

- Small businesses require (at least) biennial inspection to ensure compliance
- Major sources require annual inspection under EPA grant and CARB enforcement policy
- RECLAIM facilities require annual audit

## Compliance Inspections

Performed to determine and assure compliance with:

- Applicable air quality rule requirements
  - Local (SCAQMD)
  - State
  - Federal
- Permit conditions

## Pre-Entry

- Review permit conditions in Permit to Operate
- Review field file, prior inspection reports
- Assemble inspection kit
  - Forms
  - Outreach materials
  - Inspection & safety equipment
  - Sample containers
  - Measuring devices
- Conduct perimeter surveillance

## Entry

- Present credentials and request entry to inspect
- Absent waiver of company liability, satisfy all other entry requirements
- If denied entry, politely & professionally make additional attempts to gain access
- Seek inspection warrant as last resort if entry not allowed

## Opening Conference

- Meet with site representative
  - Verify basic site information
    - Facility name
    - Ownership
    - Complete address
    - Contact person, title, & phone number
  - Explain purpose & scope of activities

## Opening Conference

- Describe/explain applicable SCAQMD, state, and federal rule requirements
- Ask facility representative to describe on-site safety concerns & requirements
- Obtain copies of records required for compliance determination

## Rule Review

- Identify/explain applicable rule requirements
  - Self-inspection
  - Monitoring
  - Testing
  - Recordkeeping
  - Reporting

## Permit Review

- Identify/explain permit requirements
  - Permit to Construct
  - Permit to Operate
    - Equipment-specific
    - RECLAIM
    - Title V
- Verify permit is current and posted
- Verify accuracy of equipment description
- Verify application submittal(s) for equipment change(s), if any

## Evidence Gathering

- Collect, document, and authenticate relevant evidence of noncompliance
  - Interview statements
  - Observations
  - Representative samples
    - Chain of custody ensures sample integrity
  - Photocopies of records, reports, purchase receipts, invoices, methods and results of monitoring & testing activities
  - Photographs

## Closing Conference

- Reiterate importance of compliance with all applicable requirements
- Review inspection findings with site representative
- Identify compliance gaps

## Enforcement Action

- Document violations of rules & permit conditions
  - Issue Notice to Comply (NC) for first-time noncompliance with administrative requirements
  - Issue Notice of Violation (NOV) for emissions-related noncompliance or continued noncompliance with administrative requirements upon follow-up

## Civil Penalties

California Health and Safety Code §42400.8 requires that the following factors be considered in assessing civil penalties:

- The extent of harm caused by the violation.
- The nature and persistence of the violation.
- The length of time over which the violation occurs.
- The frequency of past violations.
- The record of maintenance.
- The unproven or innovative nature of the control equipment.
- Any action taken by the defendant to mitigate the violation.
- The financial burden to the defendant.

## Source Education & Outreach

- Rule-specific compliance training provided for various industry groups
  - Rules 403/403.1 (Fugitive dust)
  - Statewide Portable Equipment Registration Program (PERP)
  - Rule 461 (Gasoline dispensing facilities)
  - Rule 1403 (Asbestos demolition & renovation)
- Individual instruction and outreach provided on site to help sources understand and meet compliance requirements
- Small Business Assistance

## Air Quality Complaints

SCAQMD accepts air quality complaint calls 24 hours a day, 7 days a week


- Toll-free complaint reporting
  1-800-CUT-SMOG (1-800-288-7664)
- Web-based complaint reporting launched June 2012
  www.aqmd.gov

## Air Quality Complaint Intake

- Callers are asked to provide the following information, if known:
  - Type of the air quality complaint -- smoke, dust, odor, or other
  - Date/time of air quality incident
    - Still occurring? Occurred in past?
  - Wind direction
  - Alleged source name, address & type of operation

## Air Quality Complaint Intake

- Callers are encouraged, but not required, to provide their name, phone number & address:
  - Kept strictly confidential within SCAQMD
  - Enables the inspector to verify details and provide feedback
- Information is routed to an on-duty supervisor for review and assignment as appropriate

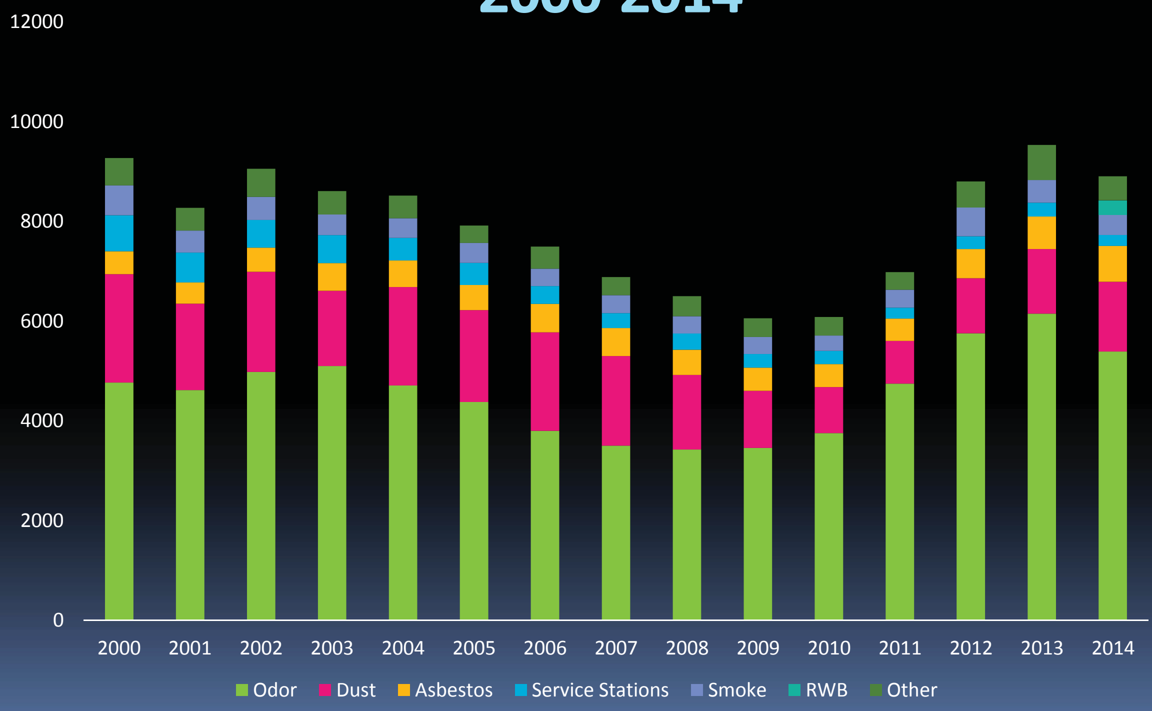
## Air Quality Complaint Resolution

- Responding quickly to air quality complaints reported by the public
  - Interviewing complainant(s) as necessary
  - Tracing emissions to their source
- Conducting surveillance in affected areas
- Conducting inspection(s) to ensure ongoing source compliance with applicable rules and regulations

## Air Quality Complaint Resolution

- Some air quality problems may be very difficult to verify.
- There may be no further action other than a follow-up call from an SCAQMD inspector during regular business hours when:
  - Emissions are intermittent, last for a brief period of time, or dissipate rapidly
  - Complaints are reported by drive-by or anonymous complainants
  - Complaints are received after hours.

# Air Quality Complaints Received 2000-2014




# SCAQMD's Authority to Regulate Odor Emissions

**RULE 402. NUISANCE*** **(Adopted May 7, 1976)**

**A person shall not discharge from any source whatsoever such quantities of air contaminants or other material:**

- **which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or**
- **which endanger the comfort, repose, health or safety of any such persons or the public, or**
- **which cause, or have a natural tendency to cause, injury or damage to business or property.**

*See also California Health & Safety Code § 41700

## Public Nuisance

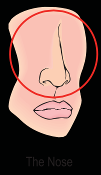
- An unreasonable interference with the rights or interests of the public (i.e., with a considerable number of people), especially when it affects or endangers life, health, or property.
- Resolution typically involves a government agency.
- SCAQMD has authority to resolve a public nuisance under SCAQMD Rule 402 and California Health & Safety Code § 41700.

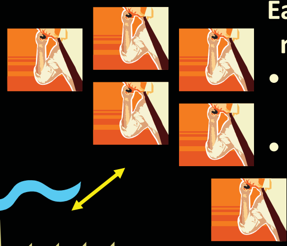
## Private Nuisance

- Use of property or course of conduct that unreasonably interferes with the legal rights or interests of private individuals in the private use and enjoyment of their land.
- Resolution involves the affected private parties.
- Some nuisances may be actionable under law but not within SCAQMD jurisdiction.

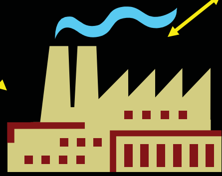
# The challenge of confirming an odor nuisance

**Odors must be:**
- Of sufficient duration and intensity
  - To be detected by complainants
  - Not to dissipate before inspector arrives
- Bothersome to complainants on detection

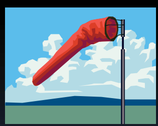


**Each complainant must be:**
- At downwind home or work location
- Willing & able to:
  - Report odors
  - Describe odors
  - Complete & sign complaint form
  - Testify in court if necessary



**Facility must be:**
- In operation
- Emitting odors



**Wind must be:**
- Blowing downwind from facility toward complainant
- Of sufficient velocity to transport odors from facility to complainants' residences/places of business

**Inspector must be:**
- Available to respond to complaints
- Careful not to solicit complaints
- Able to verify odors with complainants
- Able to track odors to their source, eliminating all other possible sources

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# Call 1-800-CUT-SMOG to report air quality problems as soon as they occur

# Refinery Team

Refinery Inspection Activities
October 20, 2015

Presented to:

Taiwan EPA Delegation

Melesio Hernandez
Air Quality Analysis & Compliance Supervisor

# Objective

- Refinery Team and Assignments
- Title V Full Compliance Evaluation (Blue Sky Inspection)
- Targeted Compliance With VOC Rules
- Other Compliance Programs

# Refinery Team Facilities

- 8 Major Refineries
- 3 Asphalt Plants
- >1,000,000 BBL/Day
- 14 Marine Terminals
- 3 Independent Hydrogen Plants

# Refinery Assignments

- Inspector Assignments
- Investigate Public Complaints
- Respond to Equipment Breakdowns
- Organize Refinery Title V Full Compliance Evaluation (Blue Sky Inspection)
- Verify Compliance with Other Programs

# Title V Full Compliance Evaluation (Blue Sky Inspection)

- Annual Major Inspection
  - Multiple Days
  - Multiple Teams
- Inspection Main Focus
  - Rule 1173 Leak Detection and Repair (LDAR) Program
  - Rule 1176 Wastewater System
  - Rules 463/1178 Storage Tanks

# SCAQMD Rule 1173

- SCAQMD Rule 1173
  - Adopted July 7, 1989
- Rule Components
  - Leak Standards
  - Identification
  - Monitoring
  - Maintenance
  - Recordkeeping

# Rule 1173 Leak Standards

| Type of Leak | Concentration |
|---|---|
| Light Liquid/Gas/Vapor | 50,000 ppm |
| Heavy Liquid | 500 ppm |
| Heavy Liquid Pump | 100 ppm |
| Light Liquid Leak | 3 drops per minute |
| PRD based on Leak Threshold | 200 ppm |
| Light Liquid/Gas/Vapor based on Leak Threshold | 10,000 ppm |

# Rule 1173 Maintenance Requirements

| Type of Leak | Concentration | Time Period | Extended Time Period |
|---|---|---|---|
| Light Liquid/Gas/Vapor | 500 ppm to 10,000 ppm | 7 Calendar Days | 7 Calendar Days |
| Heavy Liquid | 100 ppm to 500 ppm | 7 Calendar Days | 7 Calendar Days |
| Heavy Liquid | 3 Drops per minute and 100 ppm to 500 ppm | 7 Calendar Days | |
| Any Leak | 10,000 ppm to 25,000 ppm | 2 Calendar Days | 3 Calendar Days |
| Any Leak | Greater than 25,000 ppm | 1 Calendar Day | |

# Rule 1173 Maintenance Requirements

| Type of Leak | Concentration | Time Period | Extended Time Period |
|---|---|---|---|
| Atmospheric PRD | 200 ppm to 25,000 ppm | 2 Calendar Days | 3 Calendar Days |
| Light Liquid | Greater than 3 drops per minute | 1 Calendar Day | |
| Heavy Liquid | Greater than 500 ppm | 1 Calendar Day | |

# Types of Valves

# Leak Inspections

# Pump LDAR Inspection

# Liquid Leaking Component

# IR Camera Inspections

# Pressure Relief Valve


# SCAQMD Rule 1176

- This rule is intended to limit volatile organic compound emissions from wastewater systems.

# SCAQMD Rule 1176

- SCAQMD Rule 1176
  - Adopted November 3, 1989
- Rule Components
  - Identification Requirements
  - Operation and Control Requirements
  - Inspection, Monitoring, and Maintenance
  - Recordkeeping, Reporting, and Verification

# Control Requirements

- Sumps and Wastewater Separators
- Sewer Lines
- Process Drains
- Junction Boxes
- Air Pollution Control Devices

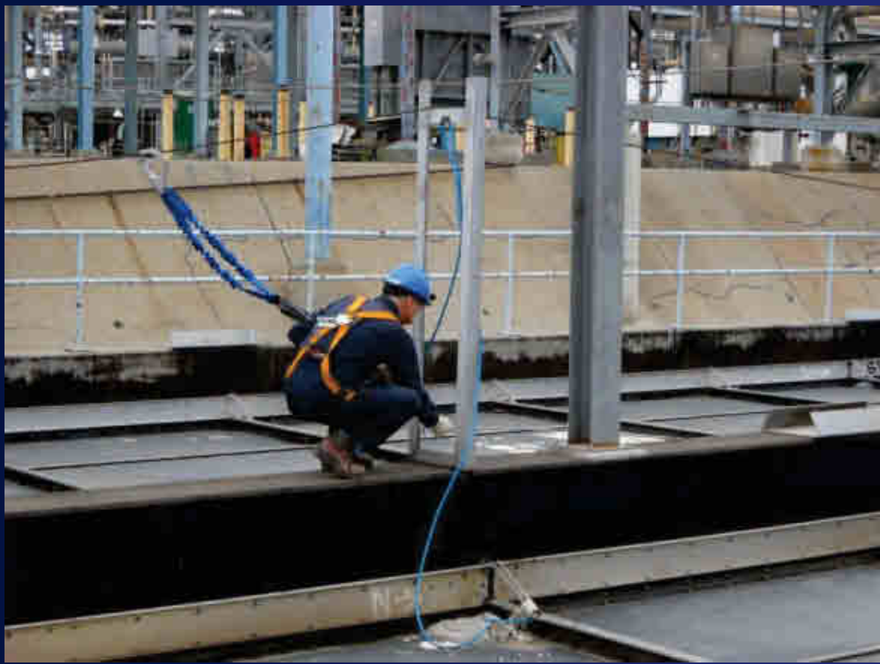
# Inspection, Monitoring and Maintenance

- Wastewater separator and associated closed vent system
  - Monthly
- Non- Emitting DSCs
  - Semi-Annual
- Inaccessible DSCs
  - Annual

# Recordkeeping, Reporting and Verification

- Recordkeeping
  - Records maintained for two years
- Reporting
  - Notification 60 days for modification
  - Quarterly and semi-annual Requirements

# Wastewater Inspections



# Sump Inspections

# Wastewater Drains

# Wastewater Separator

# SCAQMD Rule 1178

- This rule is intended to reduce volatile organic compounds from storage tanks at petroleum facilities.

# Refinery Crude Storage Tank

# Tank Emissions

# Internal Floating Roof

# Requirements

- External Floating Roof Tanks
- Domed External Floating Roof Tanks
- Internal Floating Roof Tanks
- Fixed Roof Tanks

# General Requirements

- Inspection Requirements
- Vapor Tight Conditions
  - 500 ppm VOC
- Domed External Floating Roof
  - LEL shall be less than 30%
- Maintenance Requirements
- Reporting Requirements

# Tank Inspections

# Emissions External Floating Roof

# Other Inspection Programs

- Additional Refinery Inspection Activities:
  - Contractors Equipment
    - Equipment Permit to Operate and Conditions
    - Rules 1166 & 1149 Tank Degassing & Contaminated Soil
  - Title V Permit Conditions
  - RECLAIM Rules NOx and SOx (Regulation XX)
    - Periodic Reports
    - Emissions Allocation
  - Rule 1118-Reduction of Emissions from Refinery Flare

# SCAQMD Rule 1118

- This rule is intended to reduce $SO_2$ emissions from refinery and related flaring operations.

# Amended Rule 1118 Requirements

- Allow flares to operate exclusively as safety devices, thereby reducing daily SOx emissions from flaring
- Improve monitoring, recordkeeping and reporting provisions
- Establish community notification procedures to inform the public about flare emissions and events

# Components

- Performance Targets
- Flare Monitoring and Recording Plan
- Flare Minimization Plan
- Operational Monitoring and Recording
- Stiff Penalties for exceeding Targets
- Notification and Reporting
- Testing and Monitoring

# Requirements

- Pilot Flame
- Smokeless Flares
- Notification Based on Thresholds
  - 100 pounds VOC
  - 500 pounds of sulfur dioxide
  - 500,000 standard cubic feet of vent gas
- Continuous Monitoring
- Quarterly Reports

# SOx Emission Targets

| Year | SOx (Tons/Million Barrels of Crude) |
|---|---|
| 2006 | 1.5 |
| 2008 | 1.0 |
| 2010 | 0.7 |
| 2012 | 0.5 |

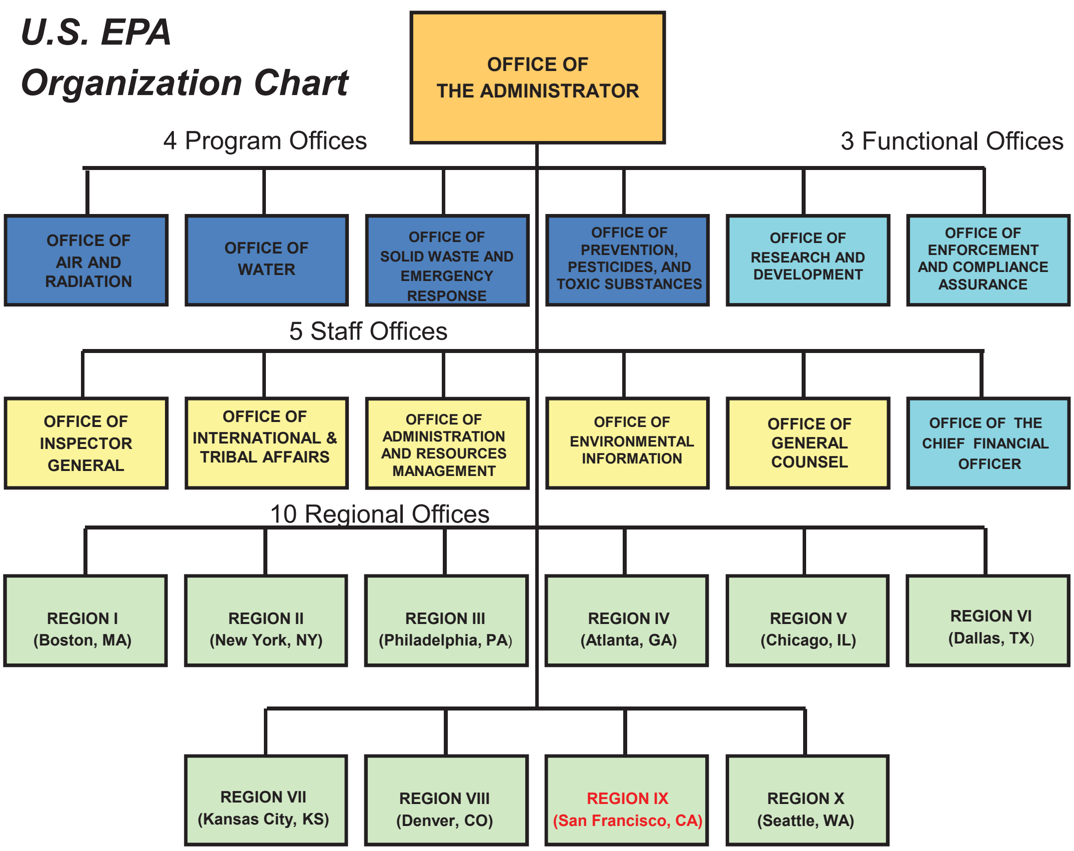
# Flare Emissions

# Questions?

# Enforcement Division- Overview

Amy C. Miller, Deputy Director

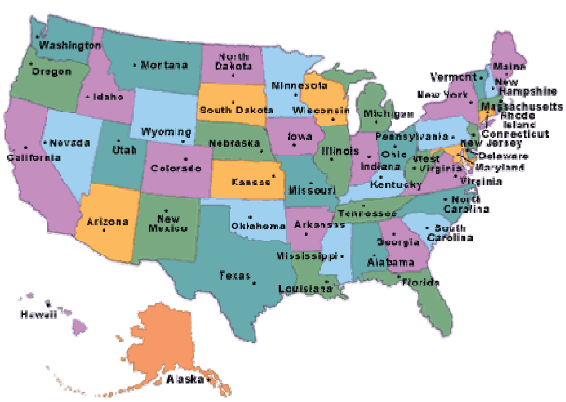
October 2015



# Regional Offices


- Execute EPA programs implementing federal environmental laws: permits, monitoring, inspection, enforcement response, state grants, audit of state programs, emergency response
- Oversee state operations: Located in 10 “Federal” Regions, cover 3-8 States each
- Address environmental issues confronting the region

# 50 States, 5 Territories and 566 Indian Tribes




- Operate delegated or approved federal programs
- Independently enact state laws and operate unique state environmental programs
- Monitor environmental conditions
- Operational activities such as issuing permits
- Compliance and enforcement programs

# Enforcement Highly Decentralized

- Over 80% of agency personnel in the Regions or field offices.
- Over 90% of inspections are conducted by State or local governments.
- EPA's enforcement budget is over $500 million with 3,400 staff
  - 2,500 in Regions, 900 in Headquarters.
  - Work is carried out by a partnership of local, state, and federal personnel.

# Use of Multiple Compliance Tools

- Writing enforceable requirements
- Compliance assistance
- Compliance monitoring
- Appropriate response to violations
  - Administrative, Civil, and Criminal
- Indicators for program evaluation

# Three Enforcement Authorities

- Criminal Prosecution
  - Knowing violation of environmental statutes.
  - May result in incarceration and/or penalty
- Civil/Judicial
  - Significant violations where judge's authority required
  - Useful for large penalties or long term/expensive relief
- Administrative
  - Internal, streamlined process with right to appeal
  - May still collect high penalties

# Civil Enforcement Response

- Response varies according to violation
- Penalties up to $37,500 per day per violation
- Policy stipulate how to calculate penalties
  - Gravity of the violation
  - Economic Benefit
- Highest civil penalties over $30,000,000
- Most cases settled out of court with judges approval of agreement.

# Why is it important to enforce the law?

- Recurrent offenders
- Imposing repair plans
- Apply Sanctions
  - Monetary sanction or fine
  - Prison
- Level playing field for industries
- Encourage others to comply

# National Priorities

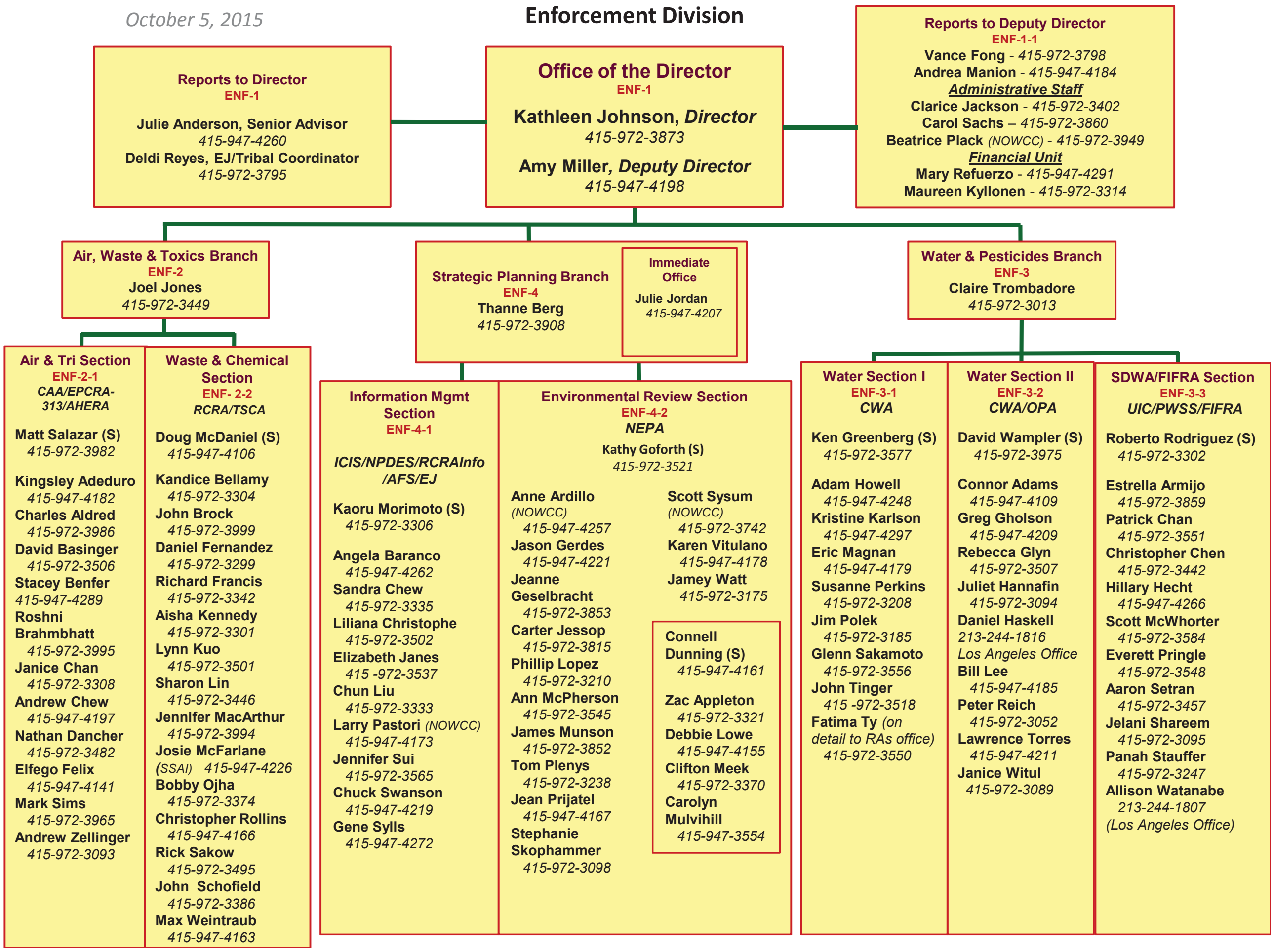
- Establishing Priorities is essential:
  - Over 40 million entities in regulated universe
  - Static and declining resources at federal and state level
- The Focus of National Priorities:
  - Environmental problems or regulatory issues that are national in scope and appropriate for federal attention and response.

# National Enforcement Initiatives 2014 - 2016

- *Air*: Reducing Air Pollution from the Largest Sources
- *Air*: Cutting Hazardous Air Pollutants
- *Water*: Keeping Raw Sewage and Contaminated Stormwater Out of Our Nation's Waters
- *Water*: Preventing Animal Waste from Contaminating Surface and Ground Water
- *Energy Extraction*: Assuring Energy Extraction Activities Comply with Environmental Laws
- *Hazardous Chemicals*: Reducing Pollution from Mineral Processing Operations

*October 5, 2015*

**Enforcement Division**



# Air/TRI Section
# CAA Highlights…

- Stationary source permits (Title V)
- Hazardous air pollutants
- NESHAP/AHERA -Asbestos
- Mobile Sources
- Community Right to Know (EPCRA Section 313)

Matt Salazar



# Water I and Water II Sections
# CWA Highlights…

- National Pollution Discharge Elimination System Permit
- Pretreatment
- Stormwater
- Wetlands
- Oil Pollution Act

Ken Greenberg

David Wampler

# SDWA/FIFRA Section
# SDWA Highlights…

- Public Water System Supervision
  - Maximum Contaminant Levels
  - Enforcement Tracker Tool
- Underground Injection Control
  - Focus on Cespools in Pacific Islands

Roberto Rodriguez



# SDWA/FIFRA Section
# FIFRA Highlights…

- Pesticide Products
  - Unregistered
  - Misbranded/Adulterated
- Container/Containment
- Misuse
- Worker Protection Standards

# Waste and Chemical Section RCRA Highlights…

- Treatment Storage and Disposal Facilities (Subtitle C)
- Generators of Hazardous Waste (Subtitle C)
- Sanitary Landfills (Subtitle D)
- Leaking Underground Storage Tanks (Subtitle I)

Doug McDaniel



# Waste and Chemical Section TSCA Highlights…

- PCBs
- Lead Based Paint
- New Chemicals

# Strategic Planning Branch

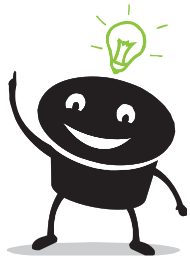
•Strategic Planning for the Enforcement Division

•Targeting

•Press/Outreach

**Information Management Section**

•Provide enforcement data management and analysis support to Enforcement Division's program offices.



•Coordinate with and provide data management support to Region 9 media divisions and state, local and tribal counterparts.

•Promote and pursue enhancement of existing and new information management systems.

# Environmental Justice

- Advise senior management team on Environmental Justice Issues
- Convene groups/governments on specific environmental justice issues.
- Award Grants to community groups.

# Environmental Review Section

- Review and comment on other federal agency's Environmental Impact Statements.
- Proactively work with federal agencies to reduce environmental impacts of their projects.
- Largest workload of any EPA regional office

# HEATER UNITS, FOR EXAMPLE

- PRE-INSPECTION WORK:
  - REVIEW PERMIT APPLICATIONS, APPROVED PERMITS, EQUIPMENT LISTS, PREVIOUS INSPECTION REPORTS, NOTICES OF VIOLATION, BREAKDOWN REPORTS, ENFORCEMENT ACTIONS TAKEN, COMPLAINTS, VARIANCE HISTORIES, ALTERNATIVE EMISSIONS CONTROL PLANS, ABATEMENT ORDERS, SOURCE TESTS, FACILITY PROCESSES AND EMISSIONS INVENTORY.
- A SAMPLE INSPECTION FORM FOR HEATERS: PRE-INSPECTION DATA IN THE LEFT HAND COLUMN AND THE RELATED FIELD ACQUIRED DATA IN THE RIGHT HAND COLUMN TO DETERMINE WHETHER OR NOT EQUIPMENT MEETS REGULATORY AND PERMIT REQUIREMENTS.

# HEATER UNITS, FOR EXAMPLE

- PRE-INSPECTION WORK:
  - DATES OF CONSTRUCTION OR MODIFICATIONS
  - RATED HEAT INPUT
  - DATE OF LAST SOURCE TEST AND TEST RESULTS
  - SULFUR IN FUEL GAS AND MONITORING RESULTS, CEMS
  - EQUIPMENT REQUIREMENTS: LOW-NOX BURNERS, SCR/SNCR (NH3 INJECTION)
- A SAMPLE INSPECTION FORM FOR OTHER UNITS: PRE-INSPECTION DATA IN THE LEFT HAND COLUMN AND THE RELATED FIELD ACQUIRED DATA IN THE RIGHT HAND COLUMN TO DETERMINE WHETHER OR NOT EQUIPMENT MEETS REGULATORY AND PERMIT REQUIREMENTS.

- Heaters used in most common processes to heat liquids: distillation, cracking (thermal, hydro, cat), reforming, hydrotreating, or hydrogen production.

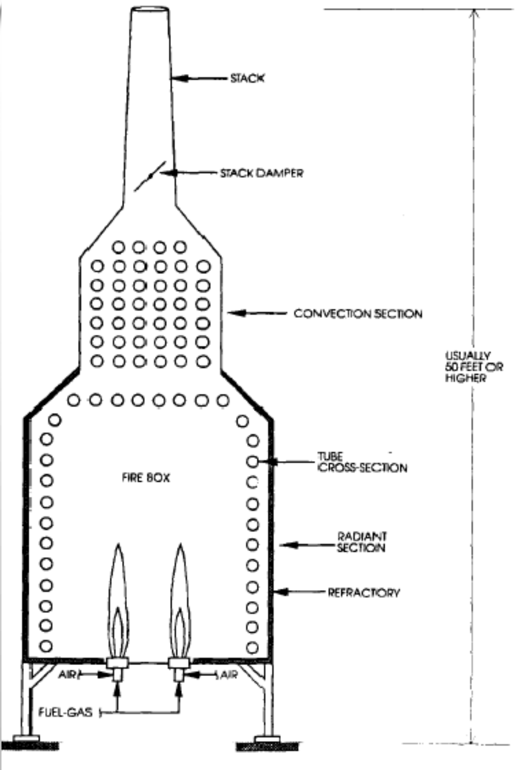



Figure 201.1
Conventional Gas-Fired Heater

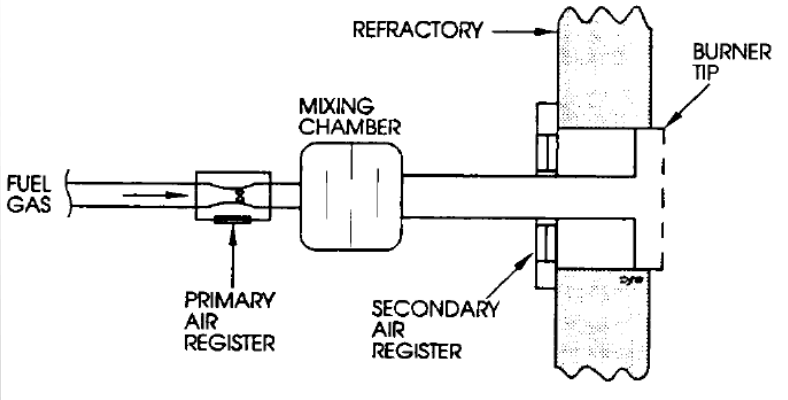



Figure 201.2
Gas Pre-mix Burner

- Heaters used in most common processes to heat liquids: distillation, cracking (thermal, hydro, cat), reforming, hydrotreating, or hydrogen production.

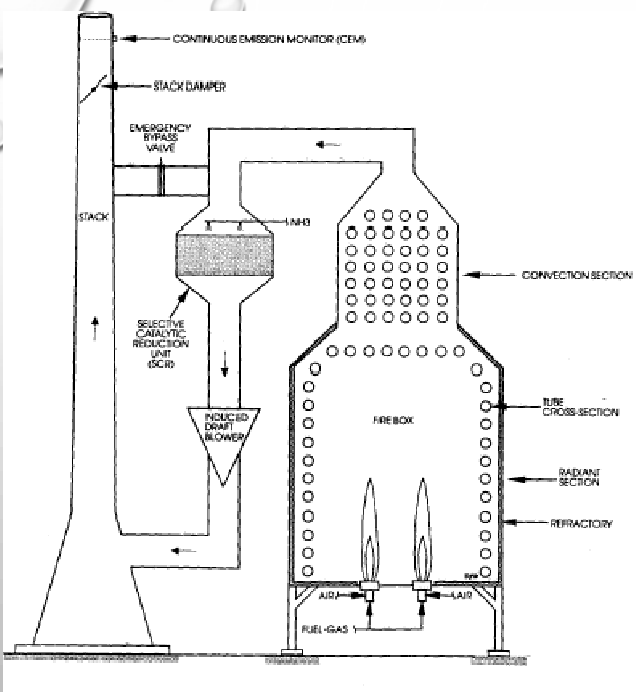



Figure 201.6
Gas-Fired Heater With Retrofit SCR System

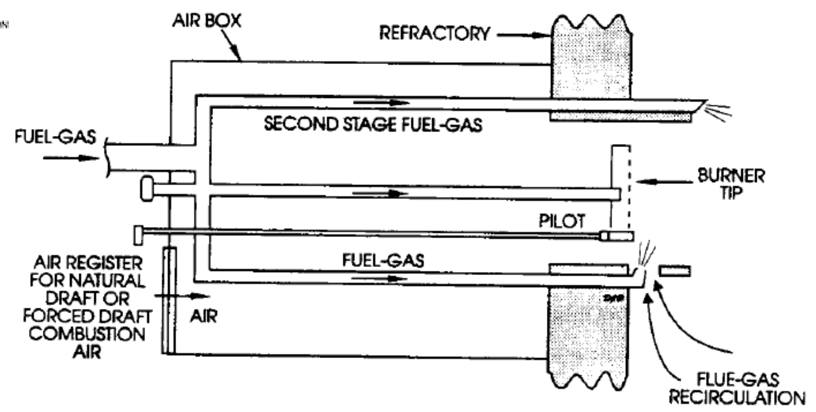



Figure 201.3
Modern Low-NOx Burner with Staged Fuel and Internal Flue-Gas Recirculation

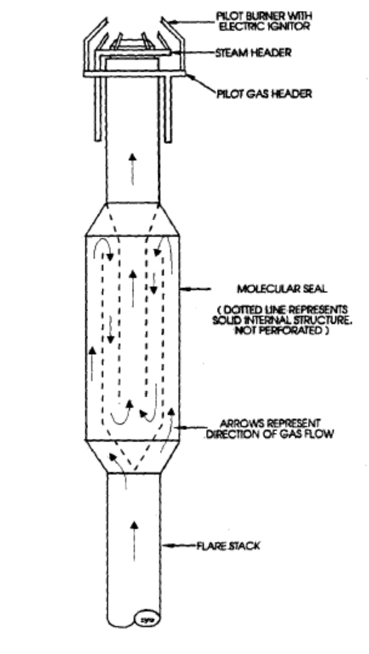



Figure 202.2
Flare Tip and Molecular Seal

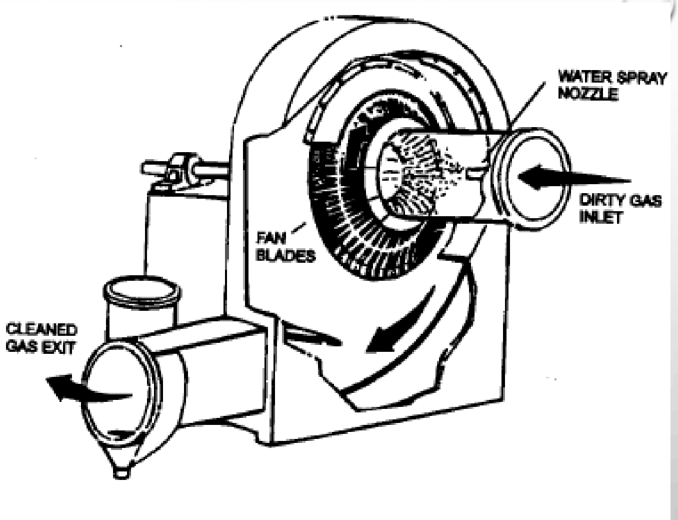


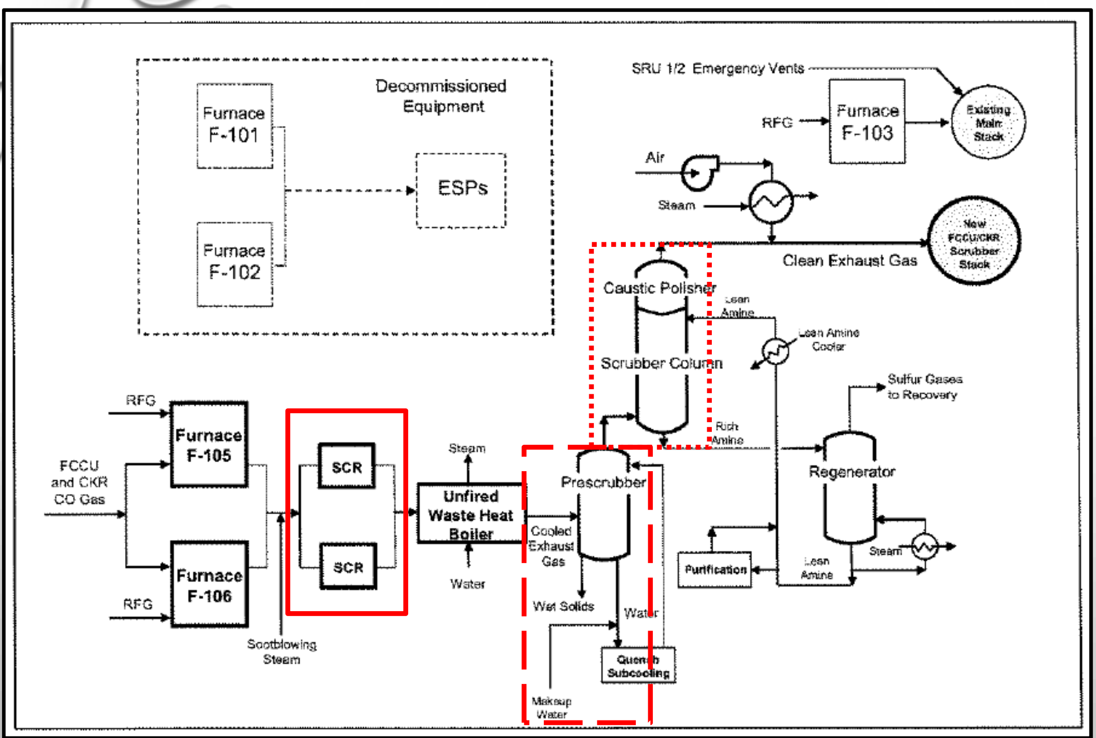

Figure 605.2 Wet Dynamic/ Mechanical Scrubber

# WET SCRUBBERS FOR PM CONTROL

- LIQUID TO GAS (L/G) RATIO IS IMPORTANT! (USU. 4-20)
  - LIQUID FLOW RATE IN GALLONS SCRUBBING LIQUID PER MINUTE (GPM)
  - GAS FLOW RATE IN ACTUAL 1,000 CUBIC FEET PER MINUTE.
- L/G MEASURED AS THE GALLONS PER MINUTE OF SCRUBBING LIQUID USED FOR EVERY 1000 ACTUAL CUBIC FEET PER MINUTE OF GAS (ACFM).
- “ACTUAL" MEANS THE GAS STREAM IS NOT CORRECTED FOR TEMPERATURE AND PRESSURE FROM STANDARD TEMPERATURE AND PRESSURE (STP).

# WET SCRUBBERS FOR PM CONTROL (CONT'D)

- TEST PORTS FOR GAS VELOCITY AT THE OUTLET FOR GAS FLOW.
- INCREASING L/G > 20 DOES NOT INCREASE PARTICLE COLLECTION EFFICIENCY BECAUSE OF DROPLET SIZE DISTRIBUTION.
- IF L/G TOO LARGE, A SLIGHT DECREASE IN COLLECTION EFFICIENCY MAY OCCUR.
- IF L/G TOO LOW, A MUCH HIGHER ADVERSE EFFECT WILL OCCUR., AND GASES COULD PASS THROUGH THE SCRUBBER WITHOUT LIQUID ABSORPTION.




## CASE STUDY

FCCU Catalytic Regenerators (NOx, SOx, CO, and PM emissions)

- General Pre-Inspection Work – File Review:
  - ✓ Permit applications,
  - ✓ approved permits,
  - ✓ equipment lists,
  - ✓ previous inspection reports,
  - ✓ notices of violation,
  - ✓ breakdown reports,
  - ✓ enforcement actions taken,
  - ✓ complaints,
  - ✓ variance histories,
  - ✓ alternative emissions control plans,
  - ✓ abatement orders,
  - ✓ source tests,
  - ✓ facility processes, and
  - ✓ emissions inventories.

- A sample inspection form for FCCU: pre-inspection data in the left hand column and the related field data in the right hand column to determine if equipment meets regulatory and permit (BACT) requirements.

- Specific Pre-Inspection Work – File Review:
  - ✓ Dates of construction or modifications
  - ✓ Gas-oil feed constraints, such as reactor feed rate
  - ✓ Date of last source test and test results
  - ✓ Sulfur limits in fuel gas and monitoring results, sulfur/H2S CEMs
  - ✓ Equipment requirements: electrostatic precipitators, CO boilers, and possibly NOx and/or SOx control devices. The Permit also may have BACT requirements for the operating parameters (voltages, temperatures, etc.) of the emission control equipment.

- Field Inspection – Reactor/Regenerator:
  - ✓ Record the gas-oil feed rate and the sulfur content of the feed and compare with any permit limits or in the regulations. Record the regenerator air rate, the regenerator outlet off-gas flow rate, and the concentrations of CO2, CO, and O2 in the off-gas. Use these values to determine the coke burn-off rate (as required in the NSPS) and to determine the mass emission rate at the stack (for comparison with the reported emissions inventory).

- Field Inspection – ESP:
  - ✓ Observe for evidence of corrosion or wear, surface skin leaks (signs of dust or smoke), and general housekeeping in the area. Record observations. Note the number of precipitators in operation and whether they are in series or parallel. Record the secondary voltage (the corona wire voltage), the spark rate, the secondary current, and the rapper timing for each section of the precipitator.
  - ✓ Check for historical data that are available on the values to expect for the voltages, currents, spark rates, or rapper timings for verifying normal operation.

- Field Inspection – CO boilers (if present):
  - ✓ Observe the flames to assure that the unit is in operation. Verify auxiliary fuel that might be used to fire the CO boiler, record the type of fuel used, the fuel use rate, and the fuel sulfur limit. Record the temperature of gas that enters the boiler, and the temperature within the boiler for evidence of proper incineration of the CO. Record the level of CO in the outlet gas.

- ✓ Verify if there is incineration of other low Btu or waste materials in the boiler. If so, verify against the Permit conditions.
- ✓ Oxidation catalyst beds may be necessary to control CO levels. CO CEMs is required. Inspection needs to determine if equipment meets regulatory and permit requirements.
- ✓ NSPS Subpart J limits CO emissions to 500 ppmv dry, 1-hr avg.
- ✓ SCAQMD SIP Rule 407 limit is no greater than 2000 ppmv.

- Field Inspection – CEMs:
    - ✓ Observe condition of NOx, SOx, CO, and opacity CEMs systems. Check to ensure they are well maintained and not ignored. Obvious loose wires or tubes typically suggest non-operational status.
    - ✓ Verify for proper calibration calibrated. Daily calibrations need to be apparent on the chart and the chart paper should have the proper range for the application.
    - ✓ Record the monitor reading and compare it to the applicable limit. Review data history for excursions. Data history could be found on a recorder chart for the instrument or in a computer database. Any excursions would trigger reporting requirements.

- Field Inspection – NOx Controls:
    - ✓ CEMs emission concentration at regenerator off-gas stack
    - ✓ Regular calibration of CEMs
    - ✓ Heat-traced sample line, if available, for portable analyzer
    - ✓ If viewing firebox for low-NOx burner staged fuel inlets at CO boilers, make sure negative pressure of -0.25 to -0.5 inches of water for safety reasons.
    - ✓ Observe that the pre-mix burner with plenty of air is generally short and compact and quite blue. Low-NOx burners may have a longer, lazier, blue and yellow flame. The second stage fuel tip can usually be seen as the source of a smaller flame located near the edge of the main burner tip. Fuel oil and diesel usually bum with very bright yellow flames which may be difficult to look at without welder's lenses. Oil flames can often be differentiated from gas flames by the intense yellow light. Use common sense and do not stare at the brightness for too long.
    - ✓ SCR inspection (if SCR installed): be aware of the position of all dampers in the duct-work to ensure no stack gas is bypassing the unit. Verify that all Permit conditions are being met. Make sure ammonia or urea injection system is intact and confirm that ammonia is being injected into the system. Record the injection rate or record the injector setting for future reference. If instrumentation has been provided to analyze for ammonia slip through the catalyst, record the slip. Record the operating temperature of the unit and verify that it is within the recommended range (typically between 550 °F and 750 °F.) If the operating temperature is not within the prescribed and historical range, try to find out why not.
    - ✓ SNCR (if installed): Check to see that ammonia is being injected into the system, then record the rate or record the injector setting for future reference. If instrumentation has been provided for ammonia slip, record the slip. Record the operating temperature at the point of injection and verify that it is within the recommended range (typically between 1400 °F and 1900 °F.)
    - ✓ NSPS regulations do not limit NOx emissions. SCAQMD SIP Rules consider the CO boiler as a typical boiler with respect to NOx emissions and the CO boiler are required to meet emission standards.
    - ✓ SCAQMD SIP Rule 1109 limit is no greater than 0.03 lbs./MMBTU or 25 ppm.

- Field Inspection – SOx Controls:
    - ✓ CEMs emission concentration at regenerator off-gas stack
    - ✓ Regular calibration of CEMs
    - ✓ Record the current sulfur monitor reading and review the data history for sulfur excursions. These values may be found on a recorder chart for the instrument or in a computer database. Verify that

any excursions were reported properly. Also verify that the instrument is being calibrated periodically as required in 40CFR 60, Appendix F.

- ✓ To repeat, these QA procedures include:
  - daily calibration with two concentrations of span gas
  - quarterly auditing of the span gas cylinder
  - yearly comparison with source test to determine relative accuracy
  - proper recordkeeping of the QA steps taken
  - records available for inspection
- ✓ If there is reason to question the H2S content of the fuel, a simple test for it can be conducted using a Drager tube. Be aware of the dangers of H2S. If the Drager results are high, borderline, or otherwise inconsistent with the continuous monitor, further evaluation may be necessary.
- ✓ NSPS Subpart J affects CO boilers mainly by limiting SOx emissions or by limiting the amount of H2S in the fuel gas to 0.10 grains per dry standard cubic foot (gr/dscf) or about 160 ppm (3 hr avg). Fresh feed to FCC must be less than 0.30 % sulfur by weight on a rolling 7-day avg. .
- ✓ SCAQMD SIP Rule 431 limit is no greater than 40 ppm sulfur compounds (as H2S) in fuel gas.

- Field Inspection – Visible Emissions:
  - ✓ Observe all stacks for emissions that violate opacity limits in applicable regulations. The inspector must be certified to do a visible emissions evaluation, with a stop watch or a watch with a second hand and means to determine ambient temperature, wet bulb temperature, and relative humidity.
  - ✓ SCAQMD SIP Rule 401 limit is no greater than 20% opacity.
  - ✓ SCAQMD SIP Rule 409 limit is no greater than 0.23 g/dscm or < 0.1 grains/dscf of particulates in the exhaust gases.

| Fluidized Catalytic Cracking Unit (FCC) Inspection Form | |
|---|---|
| Pre-Inspection: | Field Inspection: |
| Facility name: | Date/Time: |
| FCC unit ID number: | Inspector: |
| Permit number: | Authority: |
| Permit expiration date: | Facility contact person(s)/title(s):<br><br>Phone/e-mail: |
| Facility address: | |
| Date system was built or last modified: | |
| Is unit subject to NSPS Regs.? | Visible emissions noted?<br><br>Opacity as determined by Method 9 |
| Applicable stack emission limits:<br>Opacity:<br>PM:<br>NOx:<br>SOx:<br>CO:<br><br>Are CEM's required? | Are CEMs operating?<br>Are CEMs calibrated as required?<br>Opacity monitor reading:<br><br>NOx level:<br>SOx level:<br>CO level:<br>Field test results (if any) and method used: |
| Date of latest source test:<br><br>Results: | Excessive odors noted in area?<br><br>Description of odor: |

| Fluidized Catalytic Cracking Unit (FCC) Inspection Form (cont'd) | |
|---|---|
| Pre-Inspection: | Field Inspection: |
| Reactor / Regenerator Operation | |
| Rated gas-oil feed capacity:<br><br>Feed sulfur limit:<br>Permit conditions: | Gas-oil feed rate:<br>Feed weight % sulfur:<br>Regenerator air rate:<br>Regenerator outlet flow rate:<br>Regenerator outlet % CO2:<br>Regenerator outlet % CO:<br>Regenerator outlet % O2:<br>Coke burnoff rate: |
| Electrostatic Precipitator (ESP) Operation | |
| Number and type of ESP's at the facility:<br><br>Configuration (parallel or series):<br><br>Permit conditions: | Collector voltage:<br>Rapper timing:<br>Arc (spark) rate:<br>Evidence of corrosion or wear:<br>Surface skin leaks:<br>Housekeeping around hoppers and dust removal area: |
| CO Boiler Operation | |
| Auxiliary fuel type:<br>Aux. fuel sulfur limit:<br>Are other materials incinerated in CO boiler?<br>Permit conditions: | Aux. fuel use rate:<br>Aux. fuel sulfur content:<br>Temp. of gas entering boiler:<br>Combustion Temp. in boiler:<br>CO level out (ppmv): |
| Additional provisions in Permit to Operate: | |
| Recordkeeping requirements: | |

Flares (NOx, SOx, CO, and PM emissions)

- General Pre-Inspection Work – File Review:
  - ✓ Permit applications,
  - ✓ approved permits,
  - ✓ equipment lists,
  - ✓ previous inspection reports,
  - ✓ notices of violation,
  - ✓ breakdown reports,
  - ✓ enforcement actions taken,
  - ✓ complaints,
  - ✓ variance histories,
  - ✓ alternative emissions control plans,
  - ✓ abatement orders,
  - ✓ source tests,
  - ✓ facility processes, and
  - ✓ emissions inventories.

- A sample inspection form for heaters: pre-inspection data in the left hand column and the related field data in the right hand column to determine if equipment meets regulatory and permit requirements.

- Specific Pre-Inspection Work – File Review:
  - ✓ Dates of construction or modifications
  - ✓ Rated heat input
  - ✓ Date of last source test and test results
  - ✓ Sulfur limits in fuel gas and monitoring results, sulfur/H2S CEMs
  - ✓ Equipment requirements: low-NOx burners, SCR/SNCR (NH3 injection, Temperature), NOx, SOx, CO CEMs.

- Field Inspection – NOx Controls:
  - ✓ CEMs emission concentration in stack gas
  - ✓ Regular calibration of CEMs
  - ✓ Heat-traced sample line, if available, for portable analyzer
  - ✓ If viewing firebox for low-NOx burner staged fuel inlets, make sure negative pressure of -0.25 to -0.5 inches of water for safety reasons.
  - ✓ Observing pre-mix burner with plenty of air are generally short and compact and quite blue. Low-NOx burners may have a longer, lazier, blue and yellow flame. The second stage fuel tip can usually be seen as the source of a smaller flame located near the edge of the main burner tip. Fuel oil and diesel usually bum with very bright yellow flames which may be difficult to look at without welder's lenses. Oil flames can often be differentiated from gas flames by the intense yellow light. Use common sense and do not stare at the brightness for too long.
  - ✓ SCR inspection: be aware of the position of all dampers in the duct-work to ensure no stack gas is bypassing the unit. Verify that all Permit conditions are being met. Make sure ammonia or urea injection system is intact and confirm that ammonia is being injected into the system. Record the injection rate or record the injector setting for future reference. If instrumentation has been provided to analyze for ammonia slip through the catalyst, record the slip. Record the operating temperature of the unit and verify that it is within the recommended range (typically between 550 °F and 750 °F.) If the operating temperature is not within the prescribed and historical range, try to find out why not.

- ✓ SNCR: Check to see that ammonia is being injected into the system, then record the rate or record the injector setting for future reference. If instrumentation has been provided for ammonia slip, record the slip. Record the operating temperature at the point of injection and verify that it is within the recommended range (typically between 1400 °F and 1900 °F.)
- ✓ SCAQMD SIP Rule 1109 limit is no greater than 0.03 lbs./MMBTU or 25 ppm.

- Field Inspection – SOx Controls:
  - ✓ CEMs emission concentration in stack gas
  - ✓ Regular calibration of CEMs
  - ✓ Generally, light fuel grade gases are sent to a central unit where they are treated to remove sulfur compounds and mixed together to provide a homogenous fuel gas source for all of the refinery heaters. This mixed and treated stream is often equipped with a continuous sulfur monitor to assure compliance with SOx emission requirements.
  - ✓ Record the current sulfur monitor reading and review the data history for sulfur excursions. These values may be found on a recorder chart for the instrument or in a computer database. Verify that any excursions were reported properly. Also verify that the instrument is being calibrated periodically as required in 40CFR 60, Appendix F.
  - ✓ To repeat, these QA procedures include:
    - daily calibration with two concentrations of span gas
    - quarterly auditing of the span gas cylinder
    - yearly comparison with source test to determine relative accuracy
    - proper recordkeeping of the QA steps taken
    - records available for inspection
  - ✓ If there is reason to question the H2S content of the fuel, a simple test for it can be conducted using a Draeger tube. Be aware of the dangers of H2S. If the Draeger results are high, borderline, or otherwise inconsistent with the continuous monitor, further evaluation may be necessary.
  - ✓ NSPS Subpart J affects refinery heaters mainly by limiting SOx emissions or by limiting the amount of H2S in the fuel gas to 0.10 grains per dry standard cubic foot (gr/dscf) or about 160 ppm (3 hr avg).
  - ✓ SCAQMD SIP Rule 431 limit is no greater than 40 ppm sulfur compounds (as H2S) in fuel gas.

- Field Inspection – CO:
  - ✓ Oxidation catalyst beds may be necessary to control CO levels. CO CEMs sometimes required. Inspection needs to determine if equipment meets regulatory and permit requirements.
  - ✓ SCAQMD SIP Rule 407 limit is no greater than 2000 ppmv.

- Field Inspection – Visible Emissions:
  - ✓ Observe all heater stacks for emissions would violate the opacity limits in applicable regulations. The inspector must be certified to do a visible emissions evaluation, with a stop watch or a watch with a second hand and means to determine ambient temperature, wet bulb temperature, and relative humidity.
  - ✓ Smoke from gas-fired heaters is a rather uncommon occurrence, usually resulting from an inadequate supply of oxygen during combustion. Refinery personnel should be trained to report and correct any smoking stacks immediately. If smoking occurs, it is most likely to happen during start-up or for short periods before it is detected and corrected. Most heaters have sufficient instrumentation and controls on excess oxygen and often on carbon monoxide to nearly eliminate smoking under normal circumstances.
  - ✓ SCAQMD SIP Rule 401 limit is no greater than 20% opacity.

| Blowdown System and Flare Inspection Form | |
|---|---|
| <u>Pre-Inspection:</u> | <u>Field Inspection:</u> |
| Facility name: | Date/Time: |
| Flare ID number: | Inspector: |
| Permit number: | Authority: |
| Permit expiration date: | Facility address: |
| Facility Address: | Facility contact person(s)/title(s): |
| Date system was built or last modified: | |
| Units and processes served by the flare: | Odors noted in area?<br>Description of odor: |
| Are ground level monitors (GLM's) located nearby? Where?<br><br>For what compounds? | Is system flaring at this time?<br>When did episode start?<br>Source of Release?<br><br>Visible emissions noted? |
| What device is used to detect pilot flame? | GLM Readings: |
| Is a flow recorder installed? | Is pilot flame lit? |
| Is a liquid seal installed? | Do flows indicate continuous flaring or normal intermittant use? |
| Permit Conditions for purge gas? | Is liquid seal in use? |

| | |
|---|---|
| | Purge gas source:<br>Purge gas rate: |
| | Field test results (if any) and method used:<br>H2S in knockout drum:<br>H2S in purge gas:<br>Other: |
| Additional provisions in Permit to Operate: | |
| Record keeping requirements: | |

Gas-fired Heaters ($NO_x$, $SO_x$, CO, and PM emissions)

- General Pre-Inspection Work – File Review:
  - ✓ Permit applications,
  - ✓ approved permits,
  - ✓ equipment lists,
  - ✓ previous inspection reports,
  - ✓ notices of violation,
  - ✓ breakdown reports,
  - ✓ enforcement actions taken,
  - ✓ complaints,
  - ✓ variance histories,
  - ✓ alternative emissions control plans,
  - ✓ abatement orders,
  - ✓ source tests,
  - ✓ facility processes, and
  - ✓ emissions inventories.

- A sample inspection form for heaters: pre-inspection data in the left hand column and the related field data in the right hand column to determine if equipment meets regulatory and permit requirements.

- Specific Pre-Inspection Work – File Review:
  - ✓ Dates of construction or modifications
  - ✓ Rated heat input
  - ✓ Date of last source test and test results
  - ✓ Sulfur limits in fuel gas and monitoring results, sulfur/$H_2S$ CEMs
  - ✓ Equipment requirements: low-$NO_x$ burners, SCR/SNCR ($NH_3$ injection, Temperature), $NO_x$, $SO_x$, CO CEMs.

- Field Inspection – $NO_x$ Controls:
  - ✓ CEMs emission concentration in stack gas
  - ✓ Regular calibration of CEMs
  - ✓ Heat-traced sample line, if available, for portable analyzer
  - ✓ If viewing firebox for low-$NO_x$ burner staged fuel inlets, make sure negative pressure of -0.25 to -0.5 inches of water for safety reasons.
  - ✓ Observing pre-mix burner with plenty of air are generally short and compact and quite blue. Low-$NO_x$ burners may have a longer, lazier, blue and yellow flame. The second stage fuel tip can usually be seen as the source of a smaller flame located near the edge of the main burner tip. Fuel oil and diesel usually bum with very bright yellow flames which may be difficult to look at without welder's lenses. Oil flames can often be differentiated from gas flames by the intense yellow light. Use common sense and do not stare at the brightness for too long.
  - ✓ SCR inspection: be aware of the position of all dampers in the duct-work to ensure no stack gas is bypassing the unit. Verify that all Permit conditions are being met. Make sure ammonia or urea injection system is intact and confirm that ammonia is being injected into the system. Record the injection rate or record the injector setting for future reference. If instrumentation has been provided to analyze for ammonia slip through the catalyst, record the slip. Record the operating temperature of the unit and verify that it is within the recommended range (typically between 550 °F and 750 °F.) If the operating temperature is not within the prescribed and historical range, try to find out why not.

- ✓ SNCR: Check to see that ammonia is being injected into the system, then record the rate or record the injector setting for future reference. If instrumentation has been provided for ammonia slip, record the slip. Record the operating temperature at the point of injection and verify that it is within the recommended range (typically between 1400 °F and 1900 °F.)
- ✓ SCAQMD SIP Rule 1109 limit is no greater than 0.03 lbs./MMBTU or 25 ppm.

- Field Inspection – SOx Controls:
  - ✓ CEMs emission concentration in stack gas
  - ✓ Regular calibration of CEMs
  - ✓ Generally, light fuel grade gases are sent to a central unit where they are treated to remove sulfur compounds and mixed together to provide a homogenous fuel gas source for all of the refinery heaters. This mixed and treated stream is often equipped with a continuous sulfur monitor to assure compliance with SOx emission requirements.
  - ✓ Record the current sulfur monitor reading and review the data history for sulfur excursions. These values may be found on a recorder chart for the instrument or in a computer database. Verify that any excursions were reported properly. Also verify that the instrument is being calibrated periodically as required in 40CFR 60, Appendix F.
  - ✓ To repeat, these QA procedures include:
    - daily calibration with two concentrations of span gas
    - quarterly auditing of the span gas cylinder
    - yearly comparison with source test to determine relative accuracy
    - proper recordkeeping of the QA steps taken
    - records available for inspection
  - ✓ If there is reason to question the H2S content of the fuel, a simple test for it can be conducted using a Draeger tube. Be aware of the dangers of H2S. If the Draeger results are high, borderline, or otherwise inconsistent with the continuous monitor, further evaluation may be necessary.
  - ✓ NSPS Subpart J affects refinery heaters mainly by limiting SOx emissions or by limiting the amount of H2S in the fuel gas to 0.10 grains per dry standard cubic foot (gr/dscf) or about 160 ppm (3 hr avg).
  - ✓ SCAQMD SIP Rule 431 limit is no greater than 40 ppm sulfur compounds (as H2S) in fuel gas.

- Field Inspection – CO:
  - ✓ Oxidation catalyst beds may be necessary to control CO levels. CO CEMs sometimes required. Inspection needs to determine if equipment meets regulatory and permit requirements.
  - ✓ SCAQMD SIP Rule 407 limit is no greater than 2000 ppmv.

- Field Inspection – Visible Emissions:
  - ✓ Observe all heater stacks for emissions would violate the opacity limits in applicable regulations. The inspector must be certified to do a visible emissions evaluation, with a stop watch or a watch with a second hand and means to determine ambient temperature, wet bulb temperature, and relative humidity.
  - ✓ Smoke from gas-fired heaters is a rather uncommon occurrence, usually resulting from an inadequate supply of oxygen during combustion. Refinery personnel should be trained to report and correct any smoking stacks immediately. If smoking occurs, it is most likely to happen during start-up or for short periods before it is detected and corrected. Most heaters have sufficient instrumentation and controls on excess oxygen and often on carbon monoxide to nearly eliminate smoking under normal circumstances.
  - ✓ SCAQMD SIP Rule 401 limit is no greater than 20% opacity.

| Gas-Fired Heater Inspection Form | |
|---|---|
| <u>Pre-Inspection:</u> | <u>Field Inspection:</u> |
| Facility name: | Date/Time: |
| Heater ID number: | Inspector: |
| Permit number: | Authority: |
| Permit expiration date: | Facility address: |
| Process Unit: | Facility contact person(s)/title(s): |
| Heater service: | |
| Date heater was built or last modified: | Visible emissions noted? |
| Heat rating: | Excessive odors noted in area?<br>Description of odor: |
| Is unit subject to NSPS Regs.? | |
| Applicable emission limits:<br>NOx:<br>SOx:<br>CO:<br>PM:<br>Are CEM's required? | Are CEMs operating?<br>NOx level:<br>SOx level:<br>CO level:<br>Field test results (if any) and method used: |
| Date of latest source test:<br>Results: | Fuel firing rate:<br>% oxygen in Stack gas: |
| Sulfur limit in fuel-gas: | Sulfur or H2S in fuel-gas: |

| | |
|---|---|
| Is a continuous monitor for Sulfur in fuel-gas required? | Any sulfur excursions noted? |
| Is continuous NOx monitor installed? | NOx concentration from continuous monitor (if any):<br><br>Any NOx excursions noted? |
| Are low-NOx burners installed?<br><br>If yes, manufacturer/model of burner: | Do low-NOx burners agree with permit? |
| Is catalytic NOx reduction (SCR) or non-catalytic NOx reduction (SNCR) installed? | Is SCR/SNCR in operation?<br><br>What is ammonia injection rate?<br><br>Evidence of high ammonia slip?<br><br>Operating temperature: |
| Is flue gas recirculation installed? | What is flue gas recirculation rate? |
| | Description of flames in firebox: (short, long, lazy, color, flame impingement). |
| Additional provisions in Permit to Operate: | |
| Record keeping requirements: | |

Sulfur Recovery Unit (Primarly  odors indicative of $H_2S$ and $SO_2$ emissions from distillation, cracking, hydrotreating, fuel gas scrubbing, sour water stripping; and visible emissions/PM)

- General Pre-Inspection Work – File Review:
  - ✓ Permit applications,
  - ✓ approved permits,
  - ✓ equipment lists,
  - ✓ previous inspection reports,
  - ✓ notices of violation,
  - ✓ breakdown reports,
  - ✓ enforcement actions taken,
  - ✓ complaints,
  - ✓ variance histories,
  - ✓ alternative emissions control plans,
  - ✓ abatement orders,
  - ✓ source tests,
  - ✓ facility processes, and
  - ✓ emissions inventories.

- A sample inspection form for SRU: pre-inspection data in the left hand column and the related field data in the right hand column to determine if equipment meets regulatory and permit (BACT) requirements.

- Specific Pre-Inspection Work – File Review:
  - ✓ Dates of construction or modifications
  - ✓ Date of last source test and test results
  - ✓ Sulfur limits in fuel gas and monitoring results, sulfur/$H_2S$ CEMs
  - ✓ Equipment requirements: electrostatic precipitators, CO boilers, and possibly NOx and/or SOx control devices. The Permit also may have BACT requirements for the operating parameters (voltages, temperatures, etc.) of the emission control equipment.

- Field Inspection – Odors:
  - ✓ Upon complaints of rotten eggs ($H_2S$) or sharp, pungent, and sour (SOx) odors, check downwind of SRU. The source could be a fugitive leak from within the unit. Other related possible sources of odor which may or may not be located within the SRU include:
    - Sour water tankage,
    - Sour caustic tankage,
    - Sour water strippers,
    - $H_2S$ absorption tower facilities for sour gas,
    - $H_2S$ stripper tower facilities for amines (MEA or DEA),
    - Truck loading facilities for liquid sulfur, and
    - Sumps.
  - ✓ BAAQMD Rule 7-301, 7-302, and 7-303 regulate odors.  Rule 7-302 prohibits odors beyond property boundary to remain odorous after dilution with 4 parts odor-free air.  Also, these rules impose limits to emission rates of numerous specific compounds.

- Field Inspection – Sulfur Recovery Unit:
  - ✓ Sulfur is converted to hydrogen sulfide ($H_2S$) during hydrotreatment and the $H_2S$ is removed and sent to the SRU (also known as the sulfur plant) where it is converted into elemental sulfur and trucked away in liquid form. Some of the $H_2S$ may also be used to produce sulfuric acid ($H_2SO_4$), usually at a separate unit.

- ✓ Upgrading the capacity of an air blower to provide increased combustion air to the Claus plant to handle increased H2S levels can be indicative of "modification" per NSPS Subpart J (only those SRUs greater than 20 metric tons of sulfur per day).
- ✓ Likewise, a common alteration which can be easily verified is the replacement of original equipment with that of a higher horsepower rating. Horsepower ratings of pump and compressor drivers are normally included on the permit.

- Field Inspection – tail gas incinerators (if present):
  - ✓ Check for outlet temperature of the incinerator (1400 'F) and in the type of fuel used.
  - ✓ NSPS Subpart J limits CO emissions to 500 ppmv dry, 1-hr avg.
  - ✓ SCAQMD SIP Rule 407 limit is no greater than 2000 ppmv.

- Field Inspection – CEMs:
  - ✓ Observe condition of NOx, SOx, CO, and opacity CEMs systems. Check to ensure they are well maintained and not ignored. Obvious loose wires or tubes typically suggest non-operational status.
  - ✓ Verify for proper calibration calibrated. Daily calibrations need to be apparent on the chart and the chart paper should have the proper range for the application.
  - ✓ Record the monitor reading and compare it to the applicable limit. Review data history for excursions. Data history could be found on a recorder chart for the instrument or in a computer database. Any excursions would trigger reporting requirements.

- Field Inspection – SOx Controls:
  - ✓ SOx CEMs emission concentration at tail gas incineration stack; H2S and reduced sulfur CEMs if tail gases are not incinerated.
  - ✓ Regular calibration of CEMs
  - ✓ Record the sulfur monitor reading and review the limit and data history for sulfur excursions. These values may be found on a recorder chart for the instrument or in a computer database. Verify that any excursions were reported properly. Also verify that the instrument had been calibrated periodically as required in 40CFR 60, Appendix F. Daily calibrations should have been apparent on the chart and the chart paper should have the proper range for the application.
  - ✓ To repeat, these QA procedures include:
    - daily calibration with two concentrations of span gas
    - quarterly auditing of the span gas cylinder
    - yearly comparison with source test to determine relative accuracy
    - proper recordkeeping of the QA steps taken
    - records available for inspection
  - ✓ Inspect any nearby ground level monitors and record recent concentrations of H2S and/or SOx. In some cases, inspection vans with portable ground level monitors have been used downwind of a facility to measure these and other pollutants, especially when investigating odor complaints. A practical method to detect H2S at a facility boundary is to hang a piece of lead acetate paper on the downwind fence overnight. Please note that lead acetate paper can detect low levels of H,S but cannot be used to accurately determine concentrations.
  - ✓ NSPS Subpart J limits SO2 in the tail gas to no greater than 250 ppmv when the gas is incinerated. Reporting required when SO2 levels are greater than 250 ppm on a 12-hr. avg.
  - ✓ NSPS Subpart J limits H2S in the tail gas to no greater than 10 ppmv when the tail gases are not incinerated. Reporting required when H2S or reduced sulfur compounds are greater than 10 ppm on a 12-hr. avg.
  - ✓ SCAQMD SIP Rule 468 limit is no greater than 500 ppmv sulfur compounds calculated as SO2, dry at 15-min. avg; and no greater than 90 kg (198.5 lbs.) per hour of total sulfur compounds calculated as SO2. For H2S, SIP Rule 468 limit is no greater than 10 ppmv H2S, dry at 15-min. avg.

- Field Inspection – Visible Emissions:
  - ✓ Observe all stacks for emissions that violate opacity limits in applicable regulations. The inspector must be certified to do a visible emissions evaluation, with a stop watch or a watch with a second hand and means to determine ambient temperature, wet bulb temperature, and relative humidity.
  - ✓ SCAQMD SIP Rule 401 limit is no greater than 20% opacity.
  - ✓ SCAQMD SIP Rule 409 limit is no greater than 0.23 g/dscm or < 0.1 grains/dscf of particulates in the exhaust gases.

Sulfur Recovery Unit (SRU) Inspection Form

| Pre-Inspection: | Field Inspection: |
|---|---|
| Facility name: | Date/Time: |
| SRU unit ID number: | Inspector: |
| Permit number: | Authority: |
| Permit expiration date: | Facility contact person(s)/title(s): |
| Facility address: | Phone/e-mail: |
| Date system was built or last modified: | Visible emissions noted? |
| Is unit subject to NSPS Regs.? | Opacity as determined by Method 9 |
| Applicable emission limits:<br>SOx:<br>H2S:<br>Sulfur compounds:<br><br>Are CEM’s required? | Are CEMs operating?<br>Are CEMs in good working order?<br>Are CEMs calibrated as required?<br><br>SOx level:<br>H2S level:<br><br>Field test results (if any) and method used: |
| Date of latest source test:<br><br>Results: | Excessive odors noted in area?<br><br>Description of odor:<br><br>Source of odor: |
| Rated sulfur production capacity:<br><br>Limit for acid gas feed rate: | Sulfur production rate:<br><br>Acid gas feed rate: |

| Sulfur Recovery Unit (SRU) Inspection Form (cont'd) | |
|---|---|
| <u>Pre-Inspection:</u> | <u>Field Inspection:</u> |
| Is a tail gas incinerator installed?<br><br>Is incinerator required?<br><br>Outlet temperature limit:<br>Other requirements: | Is tail gas incinerator operating?<br><br><br><br>Outlet temperature:<br>Other requirements: |
| Are ground level monitors (GLMs) located nearby?<br>Where?<br><br>For what compounds? | GLM Readings: |
| What is the concentration limit of total sulfur compounds and the flow rate of the tail gas effluent? | Record concentration of total sulfur compounds and the flow rate of the tail gas effluent. |
| Additional provisions in Permit to Operate: | |
| Recordkeeping requirements: | |

EPA-452/F-03-005

# Air Pollution Control Technology Fact Sheet

**Name of Technology:** Cyclones

This type of technology is a part of the group of air pollution controls collectively referred to as "precleaners," because they are oftentimes used to reduce the inlet loading of particulate matter (PM) to downstream collection devices by removing larger, abrasive particles. Cyclones are also referred to as cyclone collectors, cyclone separators, centrifugal separators, and inertial separators. In applications where many small cyclones are operating in parallel, the entire system is called a multiple tube cyclone, multicyclone, or multiclone.

**Type of Technology:** Removal of PM by centrifugal and inertial forces, induced by forcing particulate-laden gas to change direction.

**Applicable Pollutants:**

Cyclones are used to control PM, and primarily PM greater than 10 micrometers (μm) in aerodynamic diameter. However, there are high efficiency cyclones designed to be effective for PM less than or equal to 10 μm and less than or equal to 2.5 μm in aerodynamic diameter ($PM_{10}$ and $PM_{2.5}$). Although cyclones may be used to collect particles larger than 200 μm, gravity settling chambers or simple momentum separators are usually satisfactory and less subject to abrasion (Wark, 1981; Perry, 1984).

**Achievable Emission Limits/Reductions:**

The collection efficiency of cyclones varies as a function of particle size and cyclone design. Cyclone efficiency generally <u>increases</u> with (1) particle size and/or density, (2) inlet duct velocity, (3) cyclone body length, (4) number of gas revolutions in the cyclone, (5) ratio of cyclone body diameter to gas exit diameter, (6) dust loading, and (7) smoothness of the cyclone inner wall. Cyclone efficiency will <u>decrease</u> with increases in (1) gas viscosity, (2) body diameter, (3) gas exit diameter, (4) gas inlet duct area, and (5) gas density. A common factor contributing to decreased control efficiencies in cyclones is leakage of air into the dust outlet (EPA, 1998).

Control efficiency ranges for single cyclones are often based on three classifications of cyclone, i.e., conventional, high-efficiency, and high-throughput. The control efficiency range for conventional single cyclones is estimated to be 70 to 90 percent for PM, 30 to 90 percent for $PM_{10}$, and 0 to 40 percent for $PM_{2.5}$.

High efficiency single cyclones are designed to achieve higher control of smaller particles than conventional cyclones. According to Cooper (1994), high efficiency single cyclones can remove 5 μm particles at up to 90 percent efficiency, with higher efficiencies achievable for larger particles. The control efficiency ranges for high efficiency single cyclones are 80 to 99 percent for PM, 60 to 95 percent for $PM_{10}$, and 20 to 70 percent for $PM_{2.5}$. Higher efficiency cyclones come with higher pressure drops, which require higher energy costs to move the waste gas through the cyclone. Cyclone design is generally driven by a specified pressure-drop limitation, rather than by meeting a specified control efficiency (Andriola, 1999; Perry, 1994).

According to Vatavuk (1990), high throughput cyclones are only guaranteed to remove particles greater than 20 μm, although collection of smaller particles does occur to some extent. The control efficiency ranges for high-throughput cyclones are 80 to 99 percent for PM, 10 to 40 percent for $PM_{10}$, and 0 to 10 percent for $PM_{2.5}$.

Multicyclones are reported to achieve from 80 to 95 percent collection efficiency for 5 µm particles (EPA, 1998).

**Applicable Source Type:** Point

**Typical Industrial Applications:**

Cyclones are designed for many applications. Cyclones themselves are generally not adequate to meet stringent air pollution regulations, but they serve an important purpose as precleaners for more expensive final control devices such as fabric filters or electrostatic precipitators (ESPs). In addition to use for pollution control work, cyclones are used in many process applications, for example, they are used for recovering and recycling food products and process materials such as catalysts (Cooper, 1994).

Cyclones are used extensively after spray drying operations in the food and chemical industries, and after crushing, grinding and calcining operations in the mineral and chemical industries to collect salable or useful material. In the ferrous and nonferrous metallurgical industries, cyclones are often used as a first stage in the control of PM emissions from sinter plants, roasters, kilns, and furnaces. PM from the fluid-cracking process are removed by cyclones to facilitate catalyst recycling. Fossil-fuel and wood-waste fired industrial and commercial fuel combustion units commonly use multiple cyclones (generally upstream of a wet scrubber, ESP, or fabric filter) which collect fine PM (< 2.5 µm) with greater efficiency than a single cyclone. In some cases, collected fly ash is reinjected into the combustion unit to improve PM control efficiency (AWMA, 1992; Avallone, 1996; STAPPA/ALAPCO, 1996; EPA, 1998).

**Emission Stream Characteristics:**

**a. Air Flow:** Typical gas flow rates for a single cyclone unit are 0.5 to 12 standard cubic meters per second ($sm^3$/sec) (1,060 to 25,400 standard cubic feet per minute (scfm)). Flows at the high end of this range and higher (up to approximately 50 $sm^3$/sec or 106,000 scfm) use multiple cyclones in parallel (Cooper, 1994). There are single cyclone units employed for specialized applications which have flow rates of up to approximately 30 $sm^3$/sec (63,500 scfm) and as low as 0.0005 $sm^3$/sec (1.1 scfm) (Wark, 1981; Andriola, 1999).

**b. Temperature:** Inlet gas temperatures are only limited by the materials of construction of the cyclone, and have been operated at temperatures as high as 540°C (1000°F) (Wark, 1981; Perry, 1994).

**c. Pollutant Loading:** Waste gas pollutant loadings typically range from 2.3 to 230 grams per standard cubic meter ($g/sm^3$) (1.0 to 100 grains per standard cubic foot (gr/scf)) (Wark, 1981). For specialized applications, loadings can be as high as 16,000 $g/sm^3$ (7,000 gr/scf), and as low as l $g/sm^3$ (0.44 gr/scf) (Avallone, 1996; Andriola, 1999).

**d. Other Considerations:** Cyclones perform more efficiently with higher pollutant loadings, provided that the device does not become choked. Higher pollutant loadings are generally associated with higher flow designs (Andriola, 1999).

**Emission Stream Pretreatment Requirements:**

No pretreatment is necessary for cyclones.

**Cost Information:**

The following are cost ranges (expressed in 2002 dollars) for a single conventional cyclone under typical operating conditions, developed using an EPA cost-estimating spreadsheet (EPA, 1996), and referenced to the volumetric flow rate of the waste stream treated. Flow rates higher than approximately 10 $sm^3$/sec (21,200 scfm) usually employ multiple cyclones operating in parallel. For purposes of calculating the example cost effectiveness, flow rates are assumed to be between 0.5 and 50 $sm^3$/sec (1,060 and 106,000 scfm), the PM inlet loading is assumed to be approximately 2.3 and 230 g/$sm^3$ (1.0 to 100 gr/scf) and the control efficiency is assumed to be 90 percent. The costs do not include costs for disposal or transport of collected material. Capital costs can be higher than in the ranges shown for applications which require expensive materials. As a rule, smaller units controlling a waste stream with a low PM concentration will be more expensive (per unit volumetric flow rate and per quantity of pollutant controlled) than a large unit controlling a waste stream with a high PM concentration.

a. **Capital Cost:** $4,600 to $7,400 per $sm^3$/sec ($2.20 to $3.50 per scfm)

b. **O & M Cost:** $1,500 to $18,000 per $sm^3$/sec ($0.70 to $8.50 per scfm), annually

c. **Annualized Cost:** $2,800 to $29,000 per $sm^3$/sec ($1.30 to $13.50 per scfm), annually

d. **Cost Effectiveness:** $0.47 to $440 per metric ton ($0.43 to $400 per short ton), annualized cost per ton per year of pollutant controlled

Flow rates higher than approximately 10 $sm^3$/sec (21,200 scfm), and up to approximately 50 $sm^3$/sec (106,000 scfm), usually employ multiple cyclones operating in parallel. Assuming the same range of pollutant loading and an efficiency of 90 percent, the following cost ranges (expressed in third quarter 1995 dollars) were developed for multiple cyclones, using an EPA cost-estimating spreadsheet (EPA, 1996), and referenced to the volumetric flow rate of the waste stream treated.

**Theory of Operation:**

Cyclones use inertia to remove particles from the gas stream. The cyclone imparts centrifugal force on the gas stream, usually within a conical shaped chamber. Cyclones operate by creating a double vortex inside the cyclone body. The incoming gas is forced into circular motion down the cyclone near the inner surface of the cyclone tube. At the bottom of the cyclone, the gas turns and spirals up through the center of the tube and out of the top of the cyclone (AWMA, 1992).

Particles in the gas stream are forced toward the cyclone walls by the centrifugal force of the spinning gas but are opposed by the fluid drag force of the gas traveling through and out of the cyclone. For large particles, inertial momentum overcomes the fluid drag force so that the particles reach the cyclone walls and are collected. For small particles, the fluid drag force overwhelms the inertial momentum and causes these particles to leave the cyclone with the exiting gas. Gravity also causes the larger particles that reach the cyclone walls to travel down into a bottom hopper. While they rely on the same separation mechanism as momentum separators, cyclones are more effective because they have a more complex gas flow pattern (AWMA, 1992).

Cyclones are generally classified into four types, depending on how the gas stream is introduced into the device and how the collected dust is discharged. The four types include tangential inlet, axial discharge; axial inlet, axial discharge; tangential inlet, peripheral discharge; and axial inlet, peripheral discharge. The first two types are the most common (AWMA, 1992).

Pressure drop is an important parameter because it relates directly to operating costs and control efficiency. Higher control efficiencies for a given cyclone can be obtained by higher inlet velocities, but this also increases the pressure drop. In general, 18.3 meters per second (60 feet per second) is considered the best operating velocity. Common ranges of pressure drops for cyclones are 0.5 to 1 kilopascals (kPa) (2 to 4 in. $H_2O$) for low-efficiency units (high throughput), 1 to 1.5 kPa (4 to 6 in. $H_2O$) for medium-efficiency units (conventional), and 2 to 2.5 kPa (8 to 10 in. $H_2O$) for high-efficiency units (AWMA, 1992).

When high-efficiency (which requires small cyclone diameter) and large throughput are both desired, a number of cyclones can be operated in parallel. In a multiple tube cyclone, the housing contains a large number of tubes that have a common gas inlet and outlet in the chamber. The gas enters the tubes through axial inlet vanes which impart a circular motion (AWMA, 1992). Another high-efficiency unit, the wet cyclonic separator, uses a combination of centrifugal force and water spray to enhance control efficiency.

**Advantages:**

Advantages of cyclones include (AWMA, 1992; Cooper, 1994; and EPA, 1998):

1. Low capital cost;
2. No moving parts, therefore, few maintenance requirements and low operating costs;
3. Relatively low pressure drop (2 to 6 inches water column), compared to amount of PM removed;
4. Temperature and pressure limitations are only dependent on the materials of construction;
5. Dry collection and disposal; and
6. Relatively small space requirements.

**Disadvantages:**

Disadvantages of cyclones include (AWMA, 1992; Cooper, 1994; and EPA, 1998):

1. Relatively low PM collection efficiencies, particularly for PM less than 10 μm in size;
2. Unable to handle sticky or tacky materials; and
3. High efficiency units may experience high pressure drops.

**Other Considerations:**

Using multiple cyclones, either in parallel or in series, to treat a large volume of gas results in higher efficiencies, but at the cost of a significant increase in pressure drop. Higher pressure drops translate to higher energy usage and operating costs. Several designs should be considered to achieve the optimum combination of collection efficiency and pressure drop (Cooper, 1994).

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EPA-452/F-03-028

# Air Pollution Control Technology Fact Sheet

**Name of Technology**: Dry Electrostatic Precipitator (ESP) - Wire-Plate Type

**Type of Technology:** Control Device - Capture/Disposal

**Applicable Pollutants:** Particulate Matter (PM), including particulate matter less than or equal to 10 micrometers (µm) in aerodynamic diameter ($PM_{10}$), particulate matter less than or equal to 2.5 µm in aerodynamic diameter ($PM_{2.5}$), and hazardous air pollutants (HAPs) that are in particulate form, such as most metals (mercury is the notable exception, as a significant portion of emissions are in the form of elemental vapor).

**Achievable Emission Limits/Reductions:**

Typical new equipment design efficiencies are between 99 and 99.9%. Older existing equipment have a range of actual operating efficiencies of 90 to 99.9%. While several factors determine ESP collection efficiency, ESP size is most important. Size determines treatment time; the longer a particle spends in the ESP, the greater its chance of being collected. Maximizing electric field strength will maximize ESP collection efficiency (STAPPA/ALAPCO, 1996). Collection efficiency is also affected by dust resistivity, gas temperature, chemical composition (of the dust and the gas), and particle size distribution. Cumulative collection efficiencies of PM, $PM_{10}$, and $PM_{2.5}$ for actual operating ESPs in various types of applications are presented in Table 1.

**Table 1. Cumulative PM, $PM_{10}$, and $PM_{2.5}$ Collection Efficiencies for Dry ESPs (EPA, 1998; EPA, 1997)**

| Application | Collection Efficiency (%) | | |
|---|---|---|---|
| | Total PM (EPA, 1997) | $PM_{10}$ (EPA, 1998) | $PM_{2.5}$ (EPA, 1998) |
| Coal-Fired Boilers | | | |
| Dry bottom (bituminous) | 99.2 | 97.7 | 96.0 |
| Spreader stoker (bituminous) | 99.2 | 99.4 | 97.7 |
| Primary Copper Production | | | |
| Multiple hearth roaster | 99.0 | 99.0 | 99.1 |
| Reverbatory smelter | 99.0 | 97.1 | 97.4 |
| Iron and Steel Production | | | |
| Open hearth furnace | 99.2 | 99.2 | 99.2 |

**Applicable Source Type:** Point

**Typical Industrial Applications:**

Approximately 80% of all ESPs in the U.S. are used in the electric utility industry. ESPs are also used in pulp and paper (7%), cement and other minerals (3%), and nonferrous metals industries (1%) (EPA, 1998). Common applications of dry wire-plate ESPs are presented in Table 2.

**Table 2. Typical Industrial Applications of Dry Wire-Plate ESPs (EPA, 1998)**

| Application | Source Category Code (SCC) | Are Other ESP Types Also Typically Used for this Application? |
|---|---|---|
| Utility Boilers (Coal, Oil) | 1-01-002...004 | No |
| Industrial Boilers (Coal, Oil, Wood, Liquid Waste) | 1-02-001...005<br>1-02-009,-013 | No |
| Commercial/Institutional Boilers (Coal, Oil, Wood) | 1-03-001...005<br>1-03-009 | No |
| Chemical Manufacture | Site specific | Yes |
| Non-Ferrous Metals Processing (Primary and Secondary): | | |
| Copper | 3-03-005<br>3-04-002 | Yes |
| Lead | 3-03-010<br>3-04-004 | Yes |
| Zinc | 3-03-030<br>3-04-008 | Yes |
| Aluminum | 3-03-000...002<br>3-04-001 | Yes |
| Other metals production | 3-03-011...014<br>3-04-005...006<br>3-04-010...022 | Yes |
| Ferrous Metals Processing: | | |
| Ferroalloy Production | 3-03-006...007 | No |
| Iron and Steel Production | 3-03-008...009 | Yes |
| Gray Iron Foundries | 3-04-003 | No |
| Steel Foundries | 3-04-007,-009 | Yes |
| Petroleum Refineries and Related Industries | 3-06-001...999 | No |
| Mineral Products: | | |
| Cement Manufacturing | 3-05-006...007 | No |
| Stone Quarrying and Processing | 3-05-020 | Yes |
| Other | 3-05-003...999 | Yes |
| Wood, Pulp, and Paper | 3-07-001 | Yes |
| Incineration (Municipal Waste) | 5-01-001 | Yes |

**Emission Stream Characteristics:**

a. **Air Flow:** Typical gas flow rates for wire-plate ESPs are 100 to 500 standard cubic meters per second ($sm^3$/sec) (200,000 to 1,000,000 standard cubic feet per minute (scfm)). Most smaller plate-type ESPs (50 $sm^3$/sec to 100 $sm^3$/sec, or 100,000 to 200,000 scfm) use flat plates instead of wires for the high-voltage electrodes (AWMA, 1992).

b. **Temperature:** Wire-plate ESPs can operate at very high temperatures, up to 700°C (1300°F) (AWMA, 1992). Operating gas temperature and chemical composition of the dust are key factors influencing dust resistivity and must be carefully considered in the design of an ESP.

c. **Pollutant Loading:** Typical inlet concentrations to a wire-plate ESP are 2 to 110 g/$m^3$ (1 to 50 grains per cubic foot (gr/$ft^3$)). It is common to pretreat a waste stream, usually with a mechanical collector or cyclone, to bring the pollutant loading into this range. Highly toxic flows with concentrations below 1 g/$m^3$ (0.5 gr/$ft^3$) are also sometimes controlled with ESPs (Bradburn, 1999; Boyer, 1999; Brown, 1999).

d. **Other Considerations:** In general, dry ESPs operate most efficiently with dust resistivities between $5 \times 10^3$ and $2 \times 10^{10}$ ohm-cm. In general, the most difficult particles to collect are those with aerodynamic diameters between 0.1 and 1.0 µm. Particles between 0.2 and 0.4 µm usually show the most penetration. This is most likely a result of the transition region between field and diffusion charging (EPA, 1998).

**Emission Stream Pretreatment Requirements:**

When much of the pollutant loading consists of relatively large particles, mechanical collectors such as cyclones or spray coolers may be used to reduce the load on the ESP, especially at high inlet concentrations. Gas conditioning equipment to improve ESP performance by changing dust resistivity is occasionally used as part of the original design, but more frequently it is used to upgrade existing ESPs. The equipment injects an agent into the gas stream ahead of the ESP. Usually, the agent mixes with the particles and alters their resistivity to promote higher migration velocity, and thus higher collection efficiency. Conditioning agents that are used include $SO_3$, $H_2SO_4$, sodium compounds, ammonia, and water; the conditioning agent most used is $SO_3$ (AWMA, 1992).

**Cost Information:**

The following are cost ranges (expressed in 2002 dollars) for wire-plate ESPs of conventional design under typical operating conditions, developed using EPA cost-estimating spreadsheets (EPA, 1996). Costs can be substantially higher than in the ranges shown for pollutants which require an unusually high level of control, or which require the ESP to be constructed of special materials such as stainless steel or titanium. In general, smaller units controlling a low concentration waste stream will not be as cost effective as a large unit cleaning a high pollutant load flow.

a. **Capital Cost:** \$21,000 to \$70,000 per $sm^3$/sec (\$10 to \$33 per scfm)

b. **O & M Cost:** \$6,400 to \$74,000 per $sm^3$/sec (\$3 to \$35 per scfm), annually

c. **Annualized Cost:** \$9,100 to \$81,000 per $sm^3$/sec (\$4 to \$38 per scfm), annually

d. **Cost Effectiveness:** \$38 to \$260 per metric ton (\$35 to \$236 per short ton)

**Theory of Operation:**

An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In dry ESPs, the collectors are knocked, or "rapped", by various mechanical means to dislodge the particulate, which slides downward into a hopper where they are collected. The hopper is evacuated periodically, as it becomes full. Dust is removed through a valve into a dust-handling system, such as a pneumatic conveyor, and is then disposed of in an appropriate manner.

In the wire-plate ESP, the exhaust gas flows horizontally and parallel to vertical plates of sheet metal. Plate spacing is typically between 19 to 38 cm (9 in. and 18 in.) (AWMA, 1992). The high voltage electrodes are long wires that are weighted and hang between the plates. Some later designs use rigid electrodes (hollow pipes approximately 25 mm to 40 mm in diameter) in place of wire (Cooper and Alley, 1994). Within each flow path, gas flow must pass each wire in sequence as it flows through the unit. The flow areas between the plates are called ducts. Duct heights are typically 6 to 14 m (20 to 45 feet) (EPA, 1998).

The power supplies for the ESP convert the industrial AC voltage (220 to 480 volts) to pulsating DC voltage in the range of 20,000 to 100,000 volts as needed. The voltage applied to the electrodes causes the gas between the electrodes to break down electrically, an action known as a "corona." The electrodes are usually given a negative polarity because a negative corona supports a higher voltage than does a positive corona before sparking occurs. The ions generated in the corona follow electric field lines from the wires to the collecting plates. Therefore, each wire establishes a charging zone through which the particles must pass. As larger particles (>10 µm diameter) absorb many times more ions than small particles (>1 µm diameter), the electrical forces are much stronger on the large particles (EPA, 1996).

Certain types of losses affect control efficiency. The rapping that dislodges the accumulated layer also project some of the particles (typically 12% for coal fly ash) back into the gas stream. These reentrained particles are then processed again by later sections, but the particles reentrained in the last section of the ESP have no chance to be recaptured and so escape the unit. Due to necessary clearances needed for nonelectrified internal components at the top of the ESP, part of the gas may flow around the charging zones. This is called "sneakage" and places an upper limit on the collection efficiency. Anti-sneakage baffles are placed to force the sneakage flow to mix with the main gas stream for collection in later sections (EPA, 1998).

Another major factor in the performance is the resistivity of the collected material. Because the particles form a continuous layer on the ESP plates, all the ion current must pass through the layer to reach the ground plates. This current creates an electric field in the layer, and it can become large enough to cause local electrical breakdown. When this occurs, new ions of the wrong polarity are injected into the wire-plate gap where they reduce the charge on the particles and may cause sparking. This breakdown condition is called "back corona." Back corona is prevalent when the resistivity of the layer is high, usually above $2 \times 10^{11}$ ohm-cm. Above this level, the collection ability of the unit is reduced considerably because the sever back corona causes difficulties in charging the particles. Low resistivities will also cause problems. At resistivities below $10^8$ ohm-cm, the particles are held on the plates so loosely that rapping and nonrapping reentrainment become much more severe. Hence, care must be taken in measuring or estimating resistivity because it is strongly affected by such variables as temperature, moisture, gas composition, particle composition, and surface characteristics (AWMA, 1992).

Precipitator size is related to many design parameters. One of the main parameters is the specific collection area (SCA), which is defined as the ratio of the surface area of the collection electrodes to the gas flow. Higher collection areas lead to better removal efficiencies. Collection areas normally are in the range of 40 to 160 $m^2$ per $sm^3$/second of gas flow (200-800 $ft^2$/1000 scfm), with typical values of 80 (400) (AWMA, 1992).

**Advantages:**

Dry wire-plate ESPs and other ESPs in general, because they act only on the particulate to be removed, and only minimally hinder flue gas flow, have very low pressure drops (typically less than 13 mm ( 0.5 in.) water column). As a result, energy requirements and operating costs tend to be low. They are capable of very high efficiencies, even for very small particles. They can be designed for a wide range of gas temperatures, and can handle high temperatures, up to 700°C (1300°F). Dry collection and disposal allows for easier handling. Operating costs are relatively low. ESPs are capable of operating under high pressure (to 1,030 kPa (150 psi)) or vacuum conditions. Relatively large gas flow rates can be effectively handled. (AWMA, 1992)

**Disadvantages:**

ESPs generally have high capital costs. The wire discharge electrodes (approximately 2.5 mm (0.01 in.) in diameter) are high-maintenance items. Corrosion can occur near the top of the wires because of air leakage and acid condensation. Also, long weighted wires tend to oscillate - the middle of the wire can approach the plate, causing increased sparking and wear. Newer ESP designs are tending toward rigid electrodes (Cooper and Alley, 1994).

ESPs in general are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). ESPs are also difficult to install in sites which have limited space since ESPs must be relatively large to obtain the low gas velocities necessary for efficient PM collection (Cooper and Alley, 1994). Certain particulates are difficult to collect due to extremely high or low resistivity characteristics. There can be an explosion hazard when treating combustible gases and/or collecting combustible particulates. Relatively sophisticated maintenance personnel are required, as well as special precautions to safeguard personnel from the high voltage. Dry ESPs are not recommended for removing sticky or moist particles. Ozone is produced by the negatively charged electrode during gas ionization (AWMA, 1992).

**Other Considerations:**

Dusts with very high resistivities (greater than $10^{10}$ ohm-cm) are also not well-suited for collection in dry ESPs. These particles are not easily charged, and thus are not easily collected. High-resistivity particles also form ash layers with very high voltage gradients on the collecting electrodes. Electrical breakdowns in these ash layers lead to injection of positively charged ions into the space between the discharge and collecting electrodes (back corona), thus reducing the charge on particles in this space and lowering collection efficiency. Fly ash from the combustion of low-sulfur coal typically has a high resistivity, and thus is difficult to collect (ICAC, 1999).

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EPA-452/F-03-019

# Air Pollution Control Technology Fact Sheet

**Name of Technology**: Flare

This includes elevated flares, steam-assisted flares, air-assisted flares, non-assisted flares, pressure-assisted flares, and enclosed ground flares.

**Type of Technology:** Destruction by thermal oxidation.

**Applicable Pollutants:** Volatile organic compounds (VOC), with the exception of halogenated compounds (EPA, 1995).

**Achievable Emission Limits/Reductions:**

VOC destruction efficiency depends upon an adequate flame temperature, sufficient residence time in the combustion zone, and turbulent mixing (EPA, 1992). A properly operated flare can achieve a destruction efficiency of 98 percent or greater when controlling emission streams with heat contents greater than 11 megajoules per standard cubic meter ($MJ/sm^3$) (300 British thermal units per standard cubic foot (Btu/scf)) (EPA, 1995; AWMA, 1992; EPA, 1992; EPA, 1991).

**Applicable Source Type:** Point

**Typical Industrial Applications:**

Flares can be used to control almost any VOC stream, and can typically handle large fluctuations in VOC concentration, flow rate, heating value, and inert species content. Flaring is appropriate for continuous, batch, and variable flow vent stream applications, but the primary use is that of a safety device used to control a large volume of pollutant resulting from upset conditions. Flares find their primary application in the petroleum and petrochemical industries. The majority of chemical plants and refineries have existing flare systems designed to relieve emergency process upsets that require release of large volumes of gas. These large diameter flares are designed to handle emergency releases, but can also be used to control vent streams from various process operations. Gases flared from refineries, petroleum production, and the chemical industry are composed largely of low molecular weight VOC and have high heating values. Flares used to control waste gases from blast furnaces consist of inert species and carbon monoxide with a low heating value. Gases flared from coke ovens are intermediate in composition to the other two groups and have a moderate heating value (EPA, 1995; EPA, 1992).

**Emission Stream Characteristics:**

a. **Air Flow:** The flow rate through the flare is dependent upon the properties of the waste gas stream and the configuration of the flare. Steam-, air-, and pressure-assisted flares add flow to the waste stream in order to improve flame stability. In cases where the heating value of the waste gas is too low or too high, auxiliary fuel or additional air must be added to the flow, respectively. The maximum flow through commercially available flares is about 500 standard cubic meters per second ($sm^3/sec$) (1,060,000 standard cubic feet per minute (scfm)), and the minimum can approach zero flow (EPA, 1995).

b. **Temperature:** The discharge temperature is typically in the range of 500 to 1100°C (1000 to 2000°F), depending upon the composition of the waste gas flow (AWMA, 1992).

c. **Pollutant Loading:** Depending upon the type of flare configuration (e.g., elevated or ground flares) and the source of the waste stream, the capacity of flares to treat waste gases can vary up to about 50,000 kilograms per hour (kg/hr) (100,000 pounds per hour (lb/hr)) of hydrocarbon gases for ground flares and about 1 million kg/hr (2 million lb/hr) or more for elevated flares (EPA, 1991). Flares are not subject to the safety concern of incinerators regarding having a high concentration of organics in the waste gas. This is because flaring is an open combustion process and does not have an enclosed combustion chamber that can create an explosive environment. Incinerators, however, have an enclosed combustion chamber, which requires that the concentration of the waste gas be substantially below the lower flammable level (lower explosive limit, or LEL) of the specific compound being controlled to avoid the potential for explosion (as a rule, a safety factor of four (i.e., 25% of the LEL) is used).

d. **Other Considerations:** The waste gas stream must have a heating value of greater than 11 MJ/scm (300 Btu/scf). If this minimum is not met by the waste gas, auxiliary fuel must be introduced in sufficient quantity to make up the difference (EPA, 1995).

**Emission Stream Pretreatment Requirements:**

Liquids that may be in the vent stream gas or that may condense out in the collection header and transfer lines are removed by a knock-out drum. The knock-out or disentrainment drum is typically either a horizontal or vertical vessel located at or close to the base of the flare, or a vertical vessel located inside the base of the flare stack. Liquid in the vent stream can extinguish the flame or cause irregular combustion and smoking. In addition, flaring liquids can generate a spray of burning chemicals that could reach ground level and create a safety hazard (EPA, 1995).

**Cost Information:**

Typical elevated flares are primarily safety devices which prevent the emissions of large quantities of raw unburned hydrocarbons during plant upset conditions. The capital costs of elevated flare systems can range from $10,000 to $3,000,000, depending upon the application (Gonzalez, 1999). The controlling factors in the cost of the flare are the basic support structure of the flare, the size and height, and the auxiliary equipment. Other factors influencing the cost are the degree of sophistication desired (i.e., manual vs. automatic control) and the number of appurtenances selected, such as knock-out drums, seals, controls, ladders, and platforms. The minimum flare diameter is 2.5 centimeters (cm) (1 inch); the maximum flare diameter currently commercially available is 2.3 meters (90 inches). (EPA, 1996)

Operating costs for an elevated flare depend largely upon the design of the flare (e.g., a steam-assisted flare will require steam), the flow rate (this will determine the diameter of the flare tip), and the heating value of the gas to be controlled (this will be a factor in determining the height of the flare and the amount of auxiliary natural gas required to achieve the desired destruction temperature) (EPA, 1996).

The following are cost ranges (expressed in 2002 dollars) for elevated steam-assisted flares of conventional design under typical operating conditions, developed using EPA cost-estimating spreadsheets (EPA, 1996) and referenced to the volumetric flow rate of the waste stream treated. Costs were calculated for flares with tips between 2.5 cm (2 in) and 2.3 m (90 in) in diameter, burning 100 percent combustible waste gas (no air) with a heat content of approximately 4000 kcal/$m^3$ (450 Btu/scf), and operated between 1 and 100 hours per year. Flares in the lower end of the capital, operating &

maintenance, and annualized cost ranges have higher flow capacity (approximately 90 $m^3$/s or 190,000 scfm), with a flare tip diameter of up to 2.3 m (90 in), and operate 100 hours per year or more. The higher end of the cost ranges have lower flow capacity (approximately 0.01 $m^3$/s, or 24 scfm), flare tip diameters as small as 2.5 cm (1 inch), and operate fewer than ten hours per year.

Because flares are primarily safety devices which deal with flows of short duration (generally an upset condition or an accidental release from a process) rather than a control device which treats a continuous waste stream, it is not entirely appropriate to compare the cost effectiveness of flares to other control devices. Cost per ton of pollutant controlled largely depends upon the annual hours of operation. Infrequent use of the flare (approximately ten hours per year) will result in greater cost per ton of pollutant controlled., while more frequent use (approximately 100 hours per year) is represented by the lower costs per ton of pollutant controlled in the ranges presented below.

a. **Capital Cost:** $27,000 to $4,000,000 per $sm^3$/sec ($13 to $21,000 per scfm)

b. **O & M Cost:** $2,000 to $20,000 per $sm^3$/sec ($1 to $10 per scfm), annually

c. **Annualized Cost:** $6,000 to $650,000 per $sm^3$/sec ($3 to $300 per scfm), annually

d. **Cost Effectiveness:** $17 to $6,500 per metric ton ($15 to $5,800 per short ton), annualized cost per ton per year of pollutant controlled

**Theory of Operation:**

Flaring is a VOC combustion control process in which the VOC are piped to a remote, usually elevated, location and burned in an open flame in the open air using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing for nearly complete (> 98%) VOC destruction. Completeness of combustion in a flare is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the gas stream components to complete the oxidation reaction, and available oxygen for free radical formation. Combustion is complete if all VOC are converted to carbon dioxide and water. Incomplete combustion results in some of the VOC being unaltered or converted to other organic compounds such as aldehydes or acids.

Flares are generally categorized in two ways: (1) by the height of the flare tip (i.e., ground or elevated), and (2) by the method of enhancing mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or non-assisted). Elevating the flare can prevent potentially dangerous conditions at ground level where the open flame (i.e., an ignition source) is located near a process unit. Elevating the flare also allows the products of combustion to be dispersed above working areas to reduce the effects of noise, heat, smoke, and objectionable odors.

In most flares, combustion occurs by means of a diffusion flame. A diffusion flame is one in which air diffuses across the boundary of the fuel/combustion product stream toward the center of the fuel flow, forming the envelope of a combustible gas mixture around a core of fuel gas. This mixture, on ignition, establishes a stable flame zone around the gas core above the burner tip. This inner gas core is heated by diffusion of hot combustion products from the flame zone.

Cracking can occur with the formation of small hot particles of carbon that give the flame its characteristic luminosity. If there is an oxygen deficiency and if the carbon particles are cooled to below their ignition temperature, smoking occurs. In large diffusion flames, combustion product vortices can form around burning portions of the gas and shut off the supply of oxygen. This localized instability causes flame flickering, which can be accompanied by soot formation. As in all combustion processes, an adequate air supply and good mixing are required to complete combustion and minimize smoke. The various flare designs differ primarily in their accomplishment of mixing.

Steam-assisted flares are single burner tips, elevated above ground level for safety reasons, that burn the vented gas in a diffusion flame. They reportedly account for the majority of the flares installed and are the predominant flare type found in refineries and chemical plants. To ensure an adequate air supply and good mixing, this type of flare system injects steam into the combustion zone to promote turbulence for mixing and to induce air into the flame.

Some flares use forced air to provide the combustion air and the mixing required for smokeless operation. These flares are built with a spider-shaped burner (with many small gas orifices) located inside but near the top of a steel cylinder 0.6 meters (24 inches) or more in diameter. Combustion air is provided by a fan in the bottom of the cylinder. The amount of combustion air can be varied by varying the fan speed. The principal advantage of air-assisted flares is that they can be used where steam is not available. Although air assistance is not usually used on large flares (because it is generally not economical when the gas volume is large) the number of large air-assisted flares being built is increasing.

The non-assisted flare consists of a flare tip without any auxiliary provision for enhancing the mixing of air into its flame. Its use is limited to gas streams that have a low heat content and a low carbon/hydrogen ratio that burn readily without producing smoke. These streams require less air for complete combustion, have lower combustion temperatures that minimize cracking reactions, and are more resistant to cracking.

Pressure-assisted flares use the vent stream pressure to promote mixing at the burner tip. Several vendors now market proprietary, high pressure drop burner tip designs. If sufficient vent stream pressure is available, these flares can be applied to streams previously requiring steam or air assist for smokeless operation. Pressure-assisted flares generally (but not necessarily) have the burner arrangement at ground level, and consequently, must be located in a remote area of the plant where there is plenty of space available. They have multiple burner heads that are staged to operate based on the quantity of gas being released. The size, design, number, and group arrangement of the burner heads depend on the vent gas characteristics.

An enclosed flare's burner heads are inside a shell that is internally insulated. The shell reduces noise, luminosity, and heat radiation and provides wind protection. Enclosed, or ground-based flares are generally used instead of elevated flares for aesthetic or safety reasons. A high nozzle pressure drop is usually adequate to provide the mixing necessary for smokeless operation and air or steam assistance is not required. In this context, enclosed flares can be considered a special class of pressure-assisted or non-assisted flares. The height must be adequate for creating enough draft to supply sufficient air for smokeless combustion and for dispersion of the thermal plume. These flares are always at ground level.

Enclosed flares generally have less capacity than open flares and are used to combust continuous, constant flow vent streams, although reliable and efficient operation can be attained over a wide range of design capacity. Stable combustion can be obtained with lower heat content vent gases than is possible with open flare designs (1.9 to 2.2 MJ/sm$^3$ (50 to 60 Btu/scf)), probably due to their isolation from wind effects. Enclosed flares are typically used at landfills to destroy landfill gas. (EPA, 1995)

**Advantages:**

Advantages of flares over other types of VOC oxidizers include (EPA, 1992; EPA, 1991):

1. Can be an economical way to dispose of sudden releases of large amounts of gas;
2. In many cases do not require auxiliary fuel to support combustion; and
3. Can be used to control intermittent or fluctuating waste streams.

**12. Disadvantages:**

Disadvantages of flares include (EPA, 1995):

d. Can produce undesirable noise, smoke, heat radiation, and light;
e. Can be a source of $SO_x$, $NO_x$, and CO;
f. Cannot be used to treat waste streams with halogenated compounds; and
g. Released heat from combustion is lost.

**Other Considerations:**

Flaring is considered as a control option when the heating value of the emission stream cannot be recovered because of uncertain of intermittent flow as in process upsets of emergencies. If the waste gas has a heating value high enough to sustain combustion (i.e. greater than 11 $MJ/sm^3$ or 300 Btu/scf), the stream may serve as a fuel gas for an incinerator if one is employed at the site (EPA, 1991).

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# Air Pollution Control Technology Fact Sheet

**Name of Technology**: Packed-Bed/Packed-Tower Wet Scrubber

This type of technology is a part of the group of air pollution controls collectively referred to as “wet scrubbers.” When used to control inorganic gases, they may also be referred to as “acid gas scrubbers.”

**Type of Technology:** Removal of air pollutants by inertial or diffusional impaction, reaction with a sorbent or reagent slurry, or absorption into liquid solvent.

**Applicable Pollutants:**

Primarily inorganic fumes, vapors, and gases (e.g., chromic acid, hydrogen sulfide, ammonia, chlorides, fluorides, and $SO_2$); volatile organic compounds (VOC); and particulate matter (PM), including PM less than or equal to 10 micrometers (µm) in aerodynamic diameter ($PM_{10}$), PM less than or equal to 2.5 µm in aerodynamic diameter ($PM_{2.5}$), and hazardous air pollutants (HAP) in particulate form ($PM_{HAP}$).

Absorption is widely used as a raw material and/or product recovery technique in separation and purification of gaseous streams containing high concentrations of VOC, especially water-soluble compounds such as methanol, ethanol, isopropanol, butanol, acetone, and formaldehyde (Croll Reynolds, 1999). Hydrophobic VOC can be absorbed using an amphiphilic block copolymer dissolved in water. However, as an emission control technique, it is much more commonly employed for controlling inorganic gases than for VOC. When using absorption as the primary control technique for organic vapors, the spent solvent must be easily regenerated or disposed of in an environmentally acceptable manner (EPA, 1991). When used for PM control, high concentrations can clog the bed, limiting these devices to controlling streams with relatively low dust loadings (EPA, 1998).

**Achievable Emission Limits/Reductions:**

Inorganic Gases: Control device vendors estimate that removal efficiencies range from 95 to 99 percent (EPA, 1993).

VOC: Removal efficiencies for gas absorbers vary for each pollutant-solvent system and with the type of absorber used. Most absorbers have removal efficiencies in excess of 90 percent, and packed-tower absorbers may achieve efficiencies greater than 99 percent for some pollutant-solvent systems. The typical collection efficiency range is from 70 to greater than 99 percent (EPA, 1996a; EPA, 1991).

PM: Packed-bed wet scrubbers are limited to applications in which dust loading is low, and collection efficiencies range from 50 to 95 percent, depending upon the application (EPA, 1998).

**Applicable Source Type:** Point

**Typical Industrial Applications:**

The suitability of gas absorption as a pollution control method is generally dependent on the following factors: 1) availability of suitable solvent; 2) required removal efficiency; 3) pollutant concentration in the inlet vapor;

4) capacity required for handling waste gas; and, 5) recovery value of the pollutant(s) or the disposal cost of the unrecoverable solvent (EPA, 1996a). Packed-bed scrubbers are typically used in the chemical, aluminum, coke and ferroalloy, food and agriculture, and chromium electroplating industries. These scrubbers have had limited use as part of flue gas desulfurization (FGD) systems, but the scrubbing solution flow rate must be carefully controlled to avoid flooding (EPA, 1998; EPA, 1981).

When absorption is used for VOC control, packed towers are usually more cost effective than impingement plate towers. However, in certain cases, the impingement plate design is preferred over packed-tower columns when either internal cooling is desired, or where low liquid flow rates would inadequately wet the packing (EPA, 1992).

**Emission Stream Characteristics:**

a. **Air Flow:** Typical gas flow rates for packed-bed wet scrubbers are 0.25 to 35 standard cubic meters per second ($sm^3/sec$) (500 to 75,000 standard cubic feet per minute (scfm)) (EPA, 1982; EPA, 1998).

b. **Temperature:** Inlet temperatures are usually in the range of 4 to 370°C (40 to 700°F) for waste gases in which the PM is to be controlled, and for gas absorption applications, 4 to 38°C (40 to 100°F). In general, the higher the gas temperature, the lower the absorption rate, and vice-versa. Excessively high gas temperatures also can lead to significant solvent or scrubbing liquid loss through evaporation. (Avallone, 1996; EPA, 1996a).

c. **Pollutant Loading:** Typical gaseous pollutant concentrations range from 250 to 10,000 ppmv (EPA, 1996a). Packed-bed wet scrubbers are generally limited to applications in which PM concentrations are less than 0.45 grams per standard cubic meter ($g/sm^3$) (0.20 grains per standard cubic foot (gr/scf)) to avoid clogging (EPA, 1982).

d. **Other Considerations:** For organic vapor HAP control applications, low outlet concentrations will typically be required, leading to impractically tall absorption towers, long contact times, and high liquid-gas ratios that may not be cost-effective. Wet scrubbers will generally be effective for HAP control when they are used in combination with other control devices such as incinerators or carbon adsorbers (EPA, 1991).

**Emission Stream Pretreatment Requirements:**

For absorption applications, precoolers (e.g., spray chambers, quenchers) may be needed to saturate the gas stream or to reduce the inlet air temperature to acceptable levels to avoid solvent evaporation or reduced absorption rates (EPA, 1996a).

**Cost Information:**

The following are cost ranges (expressed in 2002 dollars) for packed-bed wet scrubbers of conventional design under typical operating conditions, developed using EPA cost-estimating spreadsheets (EPA, 1996a) and referenced to the volumetric flow rate of the waste stream treated. For purposes of calculating the example cost effectiveness, the pollutant used is hydrochloric acid and the solvent is aqueous caustic soda. The costs do not include costs for post-treatment or disposal of used solvent or waste. Costs can be substantially higher than in the ranges shown for applications which require expensive materials, solvents, or treatment methods. As a rule, smaller units controlling a low concentration waste stream will be much more expensive (per unit volumetric flow rate) than a large unit cleaning a high pollutant load flow.

a. **Capital Cost:** \$23,000 to \$117,000 per $sm^3$/sec (\$11 to \$55 per scfm)

b. **O & M Cost:** \$32,000 to \$104,000 per $sm^3$/sec (\$15 to \$49 per scfm), annually

c. **Annualized Cost:** \$36,000 to \$165,000 per $sm^3$/sec (\$17 to \$78 per scfm), annually

d. **Cost Effectiveness:** \$110 to \$550 per metric ton (\$100 to \$500 per short ton), annualized cost per ton per year of pollutant controlled

**Theory of Operation:**

Packed-bed scrubbers consist of a chamber containing layers of variously-shaped packing material, such as Raschig rings, spiral rings, or Berl saddles, that provide a large surface area for liquid-particle contact. The packing is held in place by wire mesh retainers and supported by a plate near the bottom of the scrubber. Scrubbing liquid is evenly introduced above the packing and flows down through the bed. The liquid coats the packing and establishes a thin film. The pollutant to be absorbed must be soluble in the fluid. In vertical designs (packed towers), the gas stream flows up the chamber (countercurrent to the liquid). Some packed beds are designed horizontally for gas flow across the packing (crosscurrent) (EPA, 1998).

Physical absorption depends on properties of the gas stream and liquid solvent, such as density and viscosity, as well as specific characteristics of the pollutant(s) in the gas and the liquid stream (e.g., diffusivity, equilibrium solubility). These properties are temperature dependent, and lower temperatures generally favor absorption of gases by the solvent. Absorption is also enhanced by greater contacting surface, higher liquid-gas ratios, and higher concentrations in the gas stream (EPA, 1991). Chemical absorption may be limited by the rate of reaction, although the rate-limiting step is typically the physical absorption rate, not the chemical reaction rate (EPA, 1996a; EPA, 1996b).

Inorganic Gases Control:

Water is the most common solvent used to remove inorganic contaminants. Pollutant removal may be enhanced by manipulating the chemistry of the absorbing solution so that it reacts with the pollutant. Caustic solution (sodium hydroxide, NaOH) is the most common scrubbing liquid used for acid-gas control (e.g., HCl, $SO_2$, or both), though sodium carbonate ($Na_2CO_3$) and calcium hydroxide (slaked lime, $Ca[OH]_2$) are also used. When the acid gases are absorbed into the scrubbing solution, they react with alkaline compounds to produce neutral salts. The rate of absorption of the acid gases is dependent upon the solubility of the acid gases in the scrubbing liquid (EPA, 1996a; EPA, 1996b).

VOC Control:

Absorption is a commonly applied operation in chemical processing. It is used as a raw material and/or a product recovery technique in separation and purification of gaseous streams containing high concentrations of organics (e.g., in natural gas purification and coke by-product recovery operations). In absorption, the organics in the gas stream are dissolved in a liquid solvent. The contact between the absorbing liquid and the vent gas is accomplished in counter current spray towers, scrubbers, or packed or plate columns (EPA, 1995).

The use of absorption as the primary control technique for organic vapors is subject to several limiting factors. One factor is the availability of a suitable solvent. The VOC must be soluble in the absorbing liquid and even then, for any given absorbent liquid, only VOC that are soluble can be removed. Some common solvents that may be useful for volatile organics include water, mineral oils, or other nonvolatile petroleum oils. Another factor that affects the suitability of absorption for organic emissions control is the availability of vapor/liquid equilibrium data for the specific organic/solvent system in question. Such data are necessary for the design of absorber systems; however, they are not readily available for uncommon organic compounds.

The solvent chosen to remove the pollutant(s) should have a high solubility for the vapor or gas, low vapor pressure, low viscosity, and should be relatively inexpensive. Water is used to absorb VOC having relatively high water solubilities. Amphiphilic block copolymers added to water can make hydrophobic VOC dissolve in water. Other solvents such as hydrocarbon oils are used for VOC that have low water solubilities, though only in industries where large volumes of these oils are available (e.g., petroleum refineries and petrochemical plants) (EPA, 1996a).

Another consideration in the application of absorption as a control technique is the treatment or disposal of the material removed from the absorber. In most cases, the scrubbing liquid containing the VOC is regenerated in an operation known as stripping, in which the VOC is desorbed from the absorbent liquid, typically at elevated temperatures and/or under vacuum. The VOC is then recovered as a liquid by a condenser (EPA, 1995).

PM Control:

In packed-bed scrubbers, the gas stream is forced to follow a circuitous path through the packing material, on which much of the PM impacts. The liquid on the packing material collects the PM and flows down the chamber towards the drain at the bottom of the tower. A mist eliminator (also called a "de-mister") is typically positioned above/after the packing and scrubbing liquid supply. Any scrubbing liquid and wetted PM entrained in the exiting gas stream will be removed by the mist eliminator and returned to drain through the packed bed.

In a packed-bed scrubber, high PM concentrations can clog the bed, hence the limitation of these devices to streams with relatively low dust loadings. Plugging is a serious problem for packed-bed scrubbers because the packing is more difficult to access and clean than other scrubber designs. Mobile-bed scrubbers are available that are packed with low-density plastic spheres that are free to move within the packed bed. These scrubbers are less susceptible to plugging because of the increased movement of the packing material. In general, packed-bed scrubbers are more suitable for gas scrubbing than PM scrubbing because of the high maintenance requirements for control of PM (EPA, 1998).

**Advantages:**

Advantages of packed-bed towers include (AWMA, 1992):

1. Relatively low pressure drop;
2. Fiberglass-reinforced plastic (FRP) construction permits operation in highly corrosive atmospheres;
3. Capable of achieving relatively high mass-transfer efficiencies;
4. The height and/or type of packing can be changed to improve mass transfer without purchasing new equipment;
5. Relatively low capital cost;
6. Relatively small space requirements; and
7. Ability to collect PM as well as gases.

**Disadvantages:**

Disadvantages of packed-bed towers include (AWMA, 1992):

1. May create water (or liquid) disposal problem;
2. Waste product collected wet;
3. PM may cause plugging of the bed or plates;
4. When FRP construction is used, it is sensitive to temperature; and

5. Relatively high maintenance costs.

**Other Considerations:**

For gas absorption, the water or other solvent must be treated to remove the captured pollutant from the solution. The effluent from the column may be recycled into the system and used again. This is usually the case if the solvent is costly (e.g., hydrocarbon oils, caustic solutions, amphiphilic block copolymer). Initially, the recycle stream may go to a treatment system to remove the pollutants or the reaction product. Make-up solvent may then be added before the liquid stream reenters the column (EPA, 1996a).

For PM applications, wet scrubbers generate waste in the form of a slurry. This creates the need for both wastewater treatment and solid waste disposal. Initially, the slurry is treated to separate the solid waste from the water. The treated water can then be reused or discharged. Once the water is removed, the remaining waste will be in the form of a solid or sludge. If the solid waste is inert and nontoxic, it can generally be landfilled. Hazardous wastes will have more stringent procedures for disposal. In some cases, the solid waste may have value and can be sold or recycled (EPA, 1998).

Configuring a control device that optimizes control of more than one pollutant often does not achieve the highest control possible for any of the pollutants controlled alone. For this reason, waste gas flows which contain multiple pollutants (e.g., PM and $SO_2$, or PM and inorganic gases) are generally controlled with multiple control devices, occasionally more than one type of wet scrubber (EC/R, 1996).

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# Air Pollution Control Technology Fact Sheet

**Name of Technology:** Selective Catalytic Reduction (SCR)

**Type of Technology:** Control Device - Chemical reduction via a reducing agent and a catalyst.

**Applicable Pollutants:** Nitrogen Oxides (NOx)

**Achievable Emission Limits/Reductions:** SCR is capable of NOx reduction efficiencies in the range of 70% to 90% (ICAC, 2000). Higher reductions are possible but generally are not cost-effective.

**Applicable Source Type:** Point

**Typical Industrial Applications:** Stationary fossil fuel combustion units such as electrical utility boilers, industrial boilers, process heaters, gas turbines, and reciprocating internal combustion engines. In addition, SCR has been applied to nitric acid plants. (ICAC, 1997)

**Emission Stream Characteristics:**

a. **Combustion Unit Size:** In the United States, SCR has been applied to coal- and natural gas-fired electrical utility boilers ranging in size from 250 to 8,000 MMBtu/hr (25 to 800 MW) (EPA, 2002). SCR can be cost effective for large industrial boilers and process heaters operating at high to moderate capacity factors (>100 MMBtu/hr or >10MW for coal-fired and >50 MMBtu/hr or >5MW for gas-fired boilers). SCR is a widely used technology for large gas turbines.

b. **Temperature:** The NOx reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480°F to 800°F (250°C to 427°C) (ICAC, 1997). Typical SCR systems tolerate temperature fluctuations of ± 200°F (± 90°C) (EPA, 2002).

c. **Pollutant Loading:** SCR can achieve high reduction efficiencies (>70%) on NOx concentrations as low as 20 parts per million (ppm). Higher NOx levels result in increased performance; however, above 150 ppm, the reaction rate does not increase significantly (Environex, 2000). High levels of sulfur and particulate matter (PM) in the waste gas stream will increase the cost of SCR.

d. **Other Considerations:** Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NOx and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, and 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm. Ammonia slip at this levels do not result in plume formation or human health hazards. Process optimization after installation can lower slip levels.

   Waste gas streams with high levels of PM may require a sootblower. Sootblowers are installed in the SCR reactor to reduce deposition of particulate onto the catalyst. It also reduces fouling of downstream equipment by ammonium sulfates.

The pressure of the waste gas decreases significantly as it flows across the catalyst. Application of SCR generally requires installation a new or upgraded induced draft fan to recover pressure.

**Emission Stream Pretreatment Requirements:** The flue gas may require heating to raise the temperature to the optimum range for the reduction reaction. Sulfur and PM may be removed from the waste gas stream to reduce catalyst deactivation and fouling of downstream equipment.

**Cost Information:**

Capital costs are significantly higher than other types of NOx controls due to the large volume of catalyst that is required. The cost of catalyst is approximately 10,000 $\$/m^3$ (283 $\$/ft^3$). A 350 MMBtu/hr natural gas-fired boiler operating at 85% capacity requires approximately 17 $m^3$ ( 600 $ft^3$). For the same sized coal-fired boiler, the required catalyst is on the order of 42 $m^3$ (1,500 $ft^3$). (NESCAUM 2000).

SCR is a proprietary technology and designs on large combustion units are site specific. Retrofit of SCR on an existing unit can increase costs by over 30% (EPA, 2002). The increase in cost is primarily due to ductwork modification, the cost of structural steel, and reactor construction. Significant demolition and relocation of equipment may be required to provide space for the reactor.

The O&M costs of using SCR are driven by the reagent usage, catalyst replacement, and increased electrical power usage. SCR applications on large units (>100 MMBtu/hr) generally require 20,000 to 100,000 gallons of reagent per week (EPA, 2002). The catalyst operating life is on the order of 25,000 hours for coal-fired units and 40,000 hours for oil- and gas-fired units (EPA, 2002). A catalyst management plan can be developed so that only a fraction of the total catalyst inventory, rather than the entire volume, is replaced at any one time. This distributes the catalyst replacement and disposal costs more evenly over the lifetime of the system. O&M costs are greatly impacted by the capacity factor of the unit and annual versus seasonal control of $NO_X$.

O&M cost and the cost per ton of pollutant removed is greatly impacted by the capacity factor and whether SCR is utilized seasonally or year round.

Table 1a: Summary of Cost Information in $/MMBtu/hr (1999 Dollars) [a, b]

| Unit Type | Capital Cost ($/MMBtu) | O&M Cost [d] ($/MMBtu) | Annual Cost [d] ($/MMBtu) | Cost per Ton of Pollutant Removed ($/ton) |
|---|---|---|---|---|
| Industrial Coal Boiler | 10,000 - 15,000 | 300 | 1,600 | 2,000 - 5,000 |
| Industrial Oil, Gas, Wood [c] | 4,000 - 6,000 | 450 | 700 | 1,000 - 3,000 |
| Large Gas Turbine | 5,000 - 7,500 | 3,500 | 8,500 | 3,000 - 6,000 |
| Small Gas Turbine | 17,000 - 35,000 | 1,500 | 3,000 | 2,000 - 10,000 |

Table 1b: Summary of Cost Information in $/MW (1999 Dollars) [a, b]

| Unit Type | Capital Cost ($/MW) | O&M Cost [d] ($/MW) | Annual Cost [d] ($/MW) | Cost per Ton of Pollutant Removed ($/ton) |
|---|---|---|---|---|
| Industrial Coal Boiler | 1,000 - 1,500 | 30 | 160 | 2,000 - 5,000 |
| Industrial Oil, Gas, Wood [c] | 400 - 600 | 45 | 70 | 1,000 - 3,000 |
| Large Gas Turbine | 500 - 750 | 350 | 850 | 3,000 - 6,000 |
| Small Gas Turbine | 1,700- 3,500 | 150 | 300 | 2,000 - 10,000 |

[a] (ICAC, 1997; NESCAUM, 2000; EPA, 2002)
[b] Assumes 85% capacity factor and annual control of NOx
[c] SCR installed on wood fired boiler assumes a hot side electrostatic precipitator for PM removal
[d] Coal and oil O&M and annual costs are based on 350MMBtu boiler, and gas turbine O&M and annual costs are based on 75 MW and 5 MW turbine

**Theory of Operation:**

The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen.

Temperature, the amount of reducing agent, injection grid design and catalyst activity are the main factors that determine the actual removal efficiency. The use of a catalyst results in two primary advantages of the SCR process over the SNCR: higher NOx control efficiency and reactions within a lower and broader temperature range. The benefits are accompanied by a significant increase in capital and operating costs. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs. The catalyst composition, type, and physical properties affect performance, reliability, catalyst quantity required, and cost. The SCR system supplier and catalyst supplier generally guarantee the catalyst life and performance. Newer catalyst designs increase catalyst activity, surface area per unit volume, and the temperature range for the reduction reaction.

Catalyst activity is a measure of the NOx reduction reaction rate. Catalyst activity is a function of many variables including catalyst composition and structure, diffusion rates, mass transfer rates, gas temperature, and gas composition. Catalyst deactivation is caused by:

- poisoning of active sites by flue gas constituents,
- thermal sintering of active sites due to high temperatures within reactor,
- blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and
- erosion due to high gas velocities.

As the catalyst activity decreases, NOx removal decreases and ammonia slip increases. When the ammonia slip reaches the maximum design or permitted level, new catalyst must be installed. There are several different locations downstream of the combustion unit where SCR systems can be installed. Most coal-fired applications locate the reactor downstream of the economizer and upstream of the air heater and particulate control devices (hot-side). The flue gas in this location is usually within the optimum temperature window for NOx reduction reactions using metal oxide catalysts. SCR may be applied after PM and sulfur removal equipment (cold-side), however, reheating of the flue gas may be required, which significantly increases the operational costs.

SCR is very cost-effective for natural gas fired units. Less catalyst is required since the waste gas stream has lower levels of NOx, sulfur, and PM. Combined-cycle natural gas turbines frequently use SCR technology for NOx reduction. A typical combined-cycle SCR design places the reactor chamber after the superheater within a cavity of the heat recovery steam generator system (HRSG). The flue gas temperature in this area is within the operating range for base metal-type catalysts.

SCR can be used separately or in combination with other NOx combustion control technologies such as low NOx burners (LNB) and natural gas reburn (NGR). SCR can be designed to provide NOx reductions year-round or only during ozone season.

**Advantages:**

- Higher NOx reductions than low-NOx burners and Selective Non-Catalytic Reduction (SNCR)
- Applicable to sources with low NOx concentrations
- Reactions occur within a lower and broader temperature range than SNCR.
- Does not require modifications to the combustion unit

**Disadvantages:**

- Significantly higher capital and operating costs than low-NOx burners and SNCR
- Retrofit of SCR on industrial boilers is difficult and costly
- Large volume of reagent and catalyst required.
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

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