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S.C. Department of Health and
Environmental Control

Bureau of Air Quality
Prevention of Significant Deterioration Preliminary Determination

BP Amoco Chemical Company – Cooper River Plant

Wando, South Carolina
Berkeley County

Permit No. 0420-0029-CU.R1
May 25, 2018

This review was performed by the Bureau of Air Quality of the South Carolina Department of Health and Environmental Control in accordance with South Carolina Regulations for the Prevention of Significant Air Quality Deterioration.

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I. Time Line (Permitting Action History)

June 21, 2012	Representatives of BP Amoco Chemical Company - Cooper River Plant (BPCR) and TRC Environmental Corporation (TRC) met with the South Carolina Department of Health and Environmental Control Bureau of Air Quality (BAQ) personnel to discuss a proposed expedited Prevention of Significant Deterioration (PSD) construction permit application for a major plant modernization/debottleneck project.
March 20, 2013	Representatives of BPCR and TRC met with SCDHEC personnel for a second time to discuss the draft expedited PSD construction permit application, and how does the addition of two new cooling tower cells relate to the propose PSD project.
April 11, 2013	TRC, on behalf of BPCR, submitted an expedited PSD construction permit application to SCDHEC proposing to modernize and debottleneck the plant at BPCR located in Wando, South Carolina.
April 18, 2013	SCDHEC notified BPCR and TRC via email and phone that SCDHEC accepted the PSD construction permit application into the expedited program.
April 19, 2013	Engineering Services of BAQ e-mailed a copy of the application to Catherine Collins (US Fish and Wildlife Services) and Heather Ceron (US EPA – Region IV) and informed them that BAQ had deemed the application complete.
April 22, 2013	BAQ Permitting issues letter to BPCR to request additional information and clarify items in the application. Facility was given a May 6, 2013 deadline to provide requested information.
April 26, 2013	Tracy Price of SCDHEC sends email to BPCR to request additional information and clarify items regarding the modeling portions of the application.
April 26, 2013	BPCR sent email to James Robinson and Tracy Price requesting a meeting to discuss the information requested by SCDHEC.
May 2, 2013	BPCR and TRC met with SCDHEC at 2600 Bull St., Conference Room 2290, to discuss the information requested by SCDHEC.

May 8, 2013	TRC, on behalf of BPCR, submitted the information as requested by SCDHEC on April 26, 2013.
May 9, 2013	Air Quality Modeling Section (Modeling) sent email to BPCR and TRC requesting additional information on modeling items.
May 9, 2013	TRC, on behalf of BPCR, emailed additional information as requested by Modeling on May 9, 2013.
May 13, 2013	TRC, on behalf of BPCR, submitted additional information as requested by SCDHEC (James Robinson) on April 26, 2013.
May 15, 2013	Modeling sent email to BPCR and TRC requesting additional information and clarification on modeling items.
May 21, 2013	TRC, on behalf of BPCR, emailed additional information as requested by SCDHEC Modeling on May 15, 2013.
May 21, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed PSD project updates via phone call.
June 6, 2013	SCDHEC personnel held conference call with BPCR and TRC to discuss PSD netting analysis. BAQ requested that BPCR submit a proper netting analysis of PSD project.
June 12, 2013	SCDHEC personnel held conference call with BPCR and TRC to discuss additional information (control device descriptions, more detailed process and proposed changes descriptions, detail discussion synthetic minor/PSD avoidance limits, reduction in VOC emissions in Wastewater Treatment Area) needed for the PSD application.
June 12, 2013	SCDHEC personnel held conference call with EPA personnel (Katie Lusky) to discuss PSD netting analysis for BPCR PSD project.
June 14, 2013	Brent Pace of BPCR and James Robinson of SCDHEC held follow up phone call for clarification on June 12, 2013 phone call.
June 18, 2013	BAQ Permitting sent email to BPCR and TRC requesting additional information on PSD netting analysis, significant emissions increases, and other items needed for the Preliminary Determination.
June 20, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed

	PSD project updates via phone call.
June 25, 2013	James Robinson held conference call with BPCR and TRC to discuss additional information on PSD netting analysis, significant emissions increases, and other items needed for the Preliminary Determination. BPCR proposes to submit a revised PSD application.
June 26, 2013	Brent Pace of BPCR and James Robinson of SCDHEC held follow up phone call for clarification on June 25, 2013 phone call.
July 2, 2013	Brent Pace of BPCR requested a one week extension to submit a revised application, to July 12, 2013. James Robinson of SCDHEC granted one week extension.
July 10, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed clarification of PSD emissions calculations via phone call. Mr. Pace requested an additional one week extension to submit a revised application, to July 19, 2013. Mr. Robinson of SCDHEC granted additional one week extension.
July 19, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed PSD updates. Mr. Pace requested an additional two week extension to submit a revised application, to August 2, 2013. Mr. Robinson of SCDHEC granted additional two week extension.
August 2, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed PSD updates. Mr. Pace requested to put project on hold for at least three weeks, in order to decide next steps forward. Mr. Robinson of SCDHEC acknowledged hold request.
September 7, 2013	After a few email exchanges between August 2, 2013 and September 7, 2013 discussing the status of revised application, Brent Pace of BPCR and James Robinson of SCDHEC agreed that Brent Pace will notify James Robinson when BPCR is close to submitting a revised application.
December 17, 2013	Brent Pace of BPCR emailed James Robinson of SCDHEC some pages of the draft revised application to review.
January 10, 2014	James Robinson of SCDHEC emailed comments on pages of draft revised application to Brent Pace of BPCR.
January 20, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC responses to comments.
January 24, 2014	Brent Pace of BPCR and James Robinson of SCDHEC discussed

	responses to comments on pages of draft revised application.
March 11, 2014	TRC, on behalf of BPCR, submitted a revised expedited PSD construction permit application to SCDHEC.
March 14, 2014	James Robinson of SCDHEC emailed Natasha Hazziez of EPA Region 4 an electronic copy of the revised PSD application.
March 17, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR to request additional information and clarify items in the revised application.
April 3, 2014	Brent Pace of BPCR and James Robinson of SCDHEC discussed March 17, 2014 request for additional information to clarify items in the revised application.
April 9, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC some responses to March 17, 2014 request. BPCR need to send updates and replacement pages to the revised application.
April 14, 2014	James Robinson of SCDHEC emailed Natasha Hazziez of EPA Region 4 additional information for revised PSD application.
May 8, 2014	Natasha Hazziez of EPA Region 4 and James Robinson of SCDHEC discussed BPCR emissions calculations via phone call.
May 21, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC updated information on removal of synthetic minor limits.
May 23, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC updated emissions spreadsheets.
May 30, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC updated emissions spreadsheets.
June 4, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss emissions calculations, synthetic minor limit removal, BACT limits, and other PSD items.
June 9, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC updated emissions spreadsheets.
June 11, 2014	Brent Pace of BPCR and James Robinson of SCDHEC discussed removal of synthetic minor limits and BACT limits.
June 17, 2014	Brent Pace of BPCR sent an email to James Robinson of SCDHEC discussing BACT limits, synthetic minor limits, and additional

	equipment needing BACT.
June 20, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT short-term limits, synthetic minor/PSD avoidance limits, and other items pertaining to the revised PSD application.
June 25, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT analysis.
July 2, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT analysis.
July 10, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT analysis.
July 16, 2014	SCDHEC personnel held conference call with Brent Pace of BPCR to discuss BACT analysis.
July 23, 2014	Brent Pace of BPCR and James Robinson of SCDHEC discussed BACT analysis.
July 29, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR a list of discussion items on the BACT analysis.
July 29, 2014	Brent Pace of BPCR sent an email to James Robinson of SCDHEC responses to BACT analysis discussion items.
August 7, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT analysis.
August 12, 2014	TRC, on behalf of BPCR, submitted a second revised expedited PSD construction permit application to SCDHEC.
August 20, 2014	Brent Pace of BPCR and SCDHEC personnel discussed PSD application questions and potential effects of temporary compressors on BACT analysis.
August 27, 2014	Brent Pace of BPCR and James Robinson of SCDHEC briefly discussed modeling changes and control technology search.
August 29, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR a draft of the preliminary determination (PD) for comments.
September 5, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC comments on draft PD.
September 9, 2014	SCDHEC personnel held conference call with BPCR and TRC to

	discuss draft preliminary determination.
September 10, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR a draft of the statement of basis (SOB).
September 11, 2014	SCDHEC personnel held conference call with BPCR to discuss draft preliminary determination.
September 12, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC additional comments on draft PD.
September 12, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC comments on draft SOB.
September 24, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR a draft of the PSD permit.
September 25, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC comments on draft PSD permit.
September 25, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss draft PSD permit.
September 26, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR a draft of the PSD permit, SOB, and PD.
September 30, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC comments on draft PSD permit, SOB, and PD.
October 1, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR an updated draft of the PSD permit, SOB, and PD.
October 8, 2014	The BAQ placed the PSD Preliminary Determination and PSD Construction Permit No. 0420-0029-CU on public notice for a thirty-(30) day comment period by publication in *The Post & Courier* newspaper in Charleston, South Carolina. All appropriate Federal and State Officials were notified.
November 7, 2014	PSD Final Determination and PSD Construction Permit No. 0420-0029-CU Issued.
November 13, 2017	A Prevention of Significant Deterioration (PSD) pre-application meeting was held with representatives from BPCR, TRC, and the South Carolina Department of Health and Environmental Control (SC DHEC), Bureau of Air Quality (BAQ).
December 14, 2017	SC DHEC received a PSD permit application from BPCR.

December 20, 2017	Air Permitting of BAQ emailed a copy of the application to Lorinda Shepherd and Heather Ceron of the Environmental Protection Agency (EPA) and informed them that BAQ had deemed the application complete and will undergo technical review.
December 20, 2017	Air Permitting of BAQ emailed Marianne Andrews of BPCR to informing her that BAQ had deemed the application complete; the application will undergo a preliminary determination.
December 20, 2017	Air Permitting of BAQ emailed Marianne Andrews of BPCR requesting additional information regarding the material balance of carbon monoxide (CO).
December 20, 2017	Air Permitting of BAQ discussed the basis of CO Control Efficiency, via phone, with Robert VandenMeiracker of TRC.
December 20, 2017	Air Permitting of BAQ received email correspondence from Robert VandenMeiracker of TRC regarding CO Control Efficiency.
December 27, 2017	Air Permitting of BAQ mailed out to Catherine Collins, Federal Land Manager, a letter informing her that BAQ had deemed the application complete; the application will undergo a preliminary determination.
January 11, 2018	Air Permitting of BAQ received email correspondence from Marianne Andrews of BPCR regarding additional information for the material balance of carbon monoxide (CO).
January 11, 2018	Air Permitting of BAQ emailed Marianne Andrews of BPCR requesting additional information regarding the material balance of carbon monoxide (CO).
February 1, 2018	Air Permitting of BAQ received email correspondence from Marianne Andrews of BPCR regarding additional information for the material balance of carbon monoxide (CO).
February 14, 2018	Air Permitting of BAQ emailed Marianne Andrews of BPCR requesting additional information regarding the material balance of carbon monoxide (CO).
February 15, 2018	Air Permitting of BAQ discussed and requested Updated RBLC searches, via phone, with Robert VandenMeiracker of TRC.
February 19, 2018	Air Permitting of BAQ received email correspondence from Marianne Andrews of BPCR regarding additional information for

	the material balance of carbon monoxide (CO).
February 20, 2018	Air Permitting of BAQ received email correspondence from Robert VandenMeiracker of TRC regarding Updated RBLC searches.
February 26, 2018	Air Permitting of BAQ discussed and requested updated BACT Cost Analysis, via phone and email, with Robert VandenMeiracker of TRC.
March 8, 2018	Air Permitting of BAQ received email correspondence from Robert VandenMeiracker of TRC regarding updated BACT Cost Analysis.
March 26, 2018	Air Permitting of BAQ emailed Robert VandenMeiracker of TRC, requesting an updated application to include all previous updates, corrections, etc.
March 30, 2018	Air Permitting of BAQ received an updated application from Robert VandenMeiracker of TRC.
April 6, 2018	Air Permitting of BAQ emailed Robert VandenMeiracker of TRC, requesting clarification of the BACT Cost Analysis Tables.
April 9, 2018	Air Permitting of BAQ received email correspondence from Robert VandenMeiracker of TRC clarifying BACT Cost Analysis Tables.
April 12, 2018	Air Permitting of BAQ emailed Robert VandenMeiracker of TRC, Marianne Andrews of BPCR, EPA, and the Federal Land Managers drafts of the Preliminary Determination (PD), Statement of Basis (SOB), and Permit.
April 19, 2018	Air Permitting of BAQ received email correspondence from Robert VandenMeiracker of TRC with comments of the draft PD, SOB, and Permit.
April 19, 2018	Air Permitting of BAQ received email correspondence from Catherine Collins, Federal Land Manager (FLM), requesting more time to review the draft documents.
April 20 through May 1, 2018	Ongoing correspondence between Air Permitting of BAQ and Robert VandenMeiracker of TRC and Marianne Andrews of BPCR regarding the review of the draft preliminary determination by Catherine Collins, Federal Land Manager.
May 2, 2018	Air Permitting of BAQ received email correspondence from

	Catherine Collins, FLM, requesting that BPCR run Class I Area modeling (VISCREEN).
May 2, 2018	Air Permitting of BAQ received email correspondence from Robert VandenMeiracker of TRC regarding the results of the VISCREEN modeling.
May 9, 2018	Air Permitting of BAQ received email correspondence from Robert VandenMeiracker of TRC regarding additional VISCREEN modeling request from Catherine Collins, FLM.
May 17, 2018	Air Permitting of BAQ received email correspondence from Marianne Andrews of BPCR regarding the approval of the VISCREEN modeling by Catherine Collins, FLM.
May 21, 2018	Air Permitting of BAQ emailed Robert VandenMeiracker of TRC, and Marianne Andrews of BPCR a second draft of the Preliminary Determination (PD), Statement of Basis (SOB), and Permit.
May 21, 2018	Air Permitting of BAQ received email correspondence from Robert VandenMeiracker of TRC regarding the second draft of the Preliminary Determination (PD), Statement of Basis (SOB), and Permit.
May 25, 2018	The BAQ placed the PSD Preliminary Determination and PSD Construction Permit No. 0420-0029-CU.R1 on public notice for a thirty-(30) day comment period. All appropriate Federal and State Officials were notified.

II. Introduction and Preliminary Determination

A. Project Overview

BP Amoco Chemical Company – Cooper River Plant (BPCR) submitted a Prevention of Significant Deterioration (PSD) construction permit application to the South Carolina Department of Health and Environmental Control (SCDHEC), Bureau of Air Quality (BAQ), to modify the #1 and #2 Oxidation (OX) Units to remove limitations that prevent the units from operating at their unit design capacities (debottlenecking); and to make minor modifications to the #1 and #2 PTA Units to reduce operating costs. In general, these modifications will include improvements to the reaction environment, additional reaction air capacity, optimization of the recovery systems, improved Dehydration Tower (DHT) operation, improved energy recovery, removal of several emission points, addition of dense phase conveying and additional cooling tower capacity. These changes will result in increased actual hourly production and emissions rates, but will not increase maximum production rates or potential emission rates. This project is referred to as the OX Modernization/Debottleneck project.

The specific equipment revisions, additions, and removals included in the proposed project are as follows:

1. #1 OX unit
    - Replacement of the four existing reactors (BR-301 A-D) with a new single more efficient reactor (BR-301)
    - Replacement of the reactor overhead condenser system
    - Replacement of the air compressor rotor to reduce energy consumption
    - Direct injection of Paraxylene (PX) to the new reactor
    - Additional reactor overhead recovery capacity by replacing equipment with an improved design
    - Routing of 1st crystallizer (BD-401) vent to reactor off-gas recovery system
    - Maintain power recovery in off-gas expander by lowering upstream pressure drop
    - Conversion of dehydration tower (DHT) to azeotropic distillation unit
    - Change DHT overhead recovery system to a two-stage system by:
        - Converting existing DHT Scrubber (BT-702) to a one-stage acid scrubber
        - Routing the DHT Scrubber vent to the Low Pressure Absorber (LPA) (BT-603)
        - Revising the packing in the LPA
    - Change High Pressure Absorber (T-401) internal packing
    - Addition of dense phase conveying (conveyance of solids with less carrier gas)
    - Additional capacity for filters
    - Removal of the low pressure vent gas treatment (LPVGT) compressor (BC-710)
    - Removal of the solvent stripper (BT-605)

- Removal of the residue evaporator (BM-606) and catalyst recovery unit (BD-625/631/632/BE-645)
- Removal of the PX Stripper (BT-740)
- Addition of a steam turbine to generate power from excess low pressure steam
- Addition of a 82,000 gallon fixed roof NBA storage tank (size subject to change when BPCR goes through installation process)
- Replacement of existing Emergency Generator (BM-1201) with a new one
- Addition of a new Emergency Generator (BM-1204)
- Withdraw solvent/water mixture from reactor overhead condenser #1

2. #1 PTA unit
   - Revisions to crystallizer vent scrubber (CVS) (CM-301) to improve energy recovery
   - Addition of a 5th crystallizer (CD-300)
   - Addition of dense phase conveying
   - Replacement of dryer (CM-403B)
3. #2 OX unit
   - Direct injection of PX to reactor
   - Re-rating (Modification) of air compressor for additional capacity
   - Replacement of reactor overhead condenser
   - Conversion of dehydration tower (DHT) (DT-403) to an azeotropic distillation unit
   - Modification of packing or trays in DHT (DT-403), High Pressure Absorber (HPA) (DT-111), LPA (DT-302), Dryer Scrubber (DT-301) and High Pressure Vent Gas Treatment System (HPVGTS) Scrubber (DT-1821)
   - Routing of DHT (DT-403) vent to LPA system (DT-302)
   - Addition of dense phase conveying
   - Removal of Low Pressure Vent Gas Treatment (LPVGT) System compressor (DC-304)
   - Removal of solvent stripper (DT-402) system
   - Removal of the residue evaporator (DM-403) and catalyst recovery unit (DD-412/413/414/DE-416)
   - Removal of PX Stripper (DT-404)
   - Addition of a steam turbine to generate power from excess steam
   - Addition of a 75,000 gallon fixed roof NBA storage tank (size subject to change when BPCR goes through installation process)
4. #2 PTA Unit
   - Modifications to CVS (DM-601) to improve energy recovery
   - Modification of piping system from PTA Feed Drum (DD-500) to the Sundyne pumps
   - Addition of a 4th Sundyne pump
   - Addition of dense phase conveying

   - Replacement of dryer (DM-703)

5. Cooling Towers
   - Additional #1 Cooling Tower capacity
   - Additional #2 Cooling Tower capacity

The project will also include smaller items that will occur on all the units in the following general categories:

1. Additional and/or improved automation, multivariable control schemes, and on-line analyzers to increase unit reliability and improve process control.
2. Replacement of process equipment and piping that are negatively impacting maintenance costs and unit reliability.
3. Replacement of obsolete or end-of-life equipment such as piping, instruments, and computer equipment, where replacement parts are no longer available and equipment that has been determined to be too worn or corroded.
4. Replacement of exchangers and vessels to improve metallurgy, reduce corrosion, and reduce maintenance costs.

As part of this project, BPCR is removing synthetic minor PSD avoidance limits that were established in construction permits 0420-0029-CF, -CJ, -CP, and -CR for the following emission points: #1 OX DHT Scrubber, #1 and #2 OX LPA's, #1 and #2 OX HPVGTS, #2 PTA Crystallizer Vent Scrubber (CVS), #2 OX HPVGTS Heater, and the combined limit for CR#1 and CR#2 Plants. The table below lists the individual synthetic minor limits that will be removed. These emission points have been included in the BACT analysis.

Table II-1: Synthetic Minor Limits To Be Removed

OP ID	CP ID(s)	Process/Equipment (Equipment ID)	Pollutant	Emission Limitation (lb/hr)	Emission Limitation (TPY)	Proposed BACT Limit (lb/hr)
03	CP & CR	#1 OX LPA (BT-603)	VOC	40	80	9.60
03	CR	#1 OX LPA (BT-603)	CO	N/A	40	14.0
03	CP & CR	#1 OX DHT Scrubber (BT-702)	VOC	60	165	N/A(1)
03	CR	#1 OX DHT Scrubber (BT-702)	CO	N/A	380	
03	CJ & CR	#1 OX HPVGTS (HPA (BT-401))	VOC	85	80	4.70
03	CJ & CR	#1 OX HPVGTS (HPA (BT-401))	CO	1452	375	72.0
05	CF(2)	#2 OX LPA (DT-302)	VOC	15.57	N/A	8.85
		#2 OX HPVGTS (HPA (DT-111))				3.50
05	CF(2)	#2 PTA Unit CVS (DM-601)	VOC	25.6	N/A	20.0
05	CF(2)	#2 OX Fugitives	VOC	3.5	N/A	HON LDAR
05	CF(2)	#2 OX HPVGTS Fired Heater	VOC	0.84	N/A	0.0055 lb/MM BTU

Table II-1: Synthetic Minor Limits To Be Removed

OP ID	CP ID(s)	Process/Equipment (Equipment ID)	Pollutant	Emission Limitation (lb/hr)	Emission Limitation (TPY)	Proposed BACT Limit (lb/hr)
03-06	CP	Combined total for CR#1 & CR#2	VOC	N/A	1825	Replaced with individual vent limits

(1) The #1 OX DHT Scrubber will no longer vent to the atmosphere and is being routed to the #1 OX LPA. The #1 OX LPA BACT limit accounts for the #1 OX DHT Scrubber emissions.

(2) Construction Permit 0420-0029-CF established a total PSD avoidance limit of 49.26 lb VOC/hr for the Cooper River #2 Plant. This limit consisted of these four sources of emissions, and the following sources of emissions: Incremental increase from the Tank Farm (0.02 lb/hr) and Wastewater Fugitives (3.11 lb/hr), the Anaerobic Reactor (0.31 lb/hr), and the CO_2 Stripper (0.35 lb/hr). A revised PSD avoidance SM limit established through construction permit 0420-0029 will be the sum of the emissions from the Tank Farm, Wastewater Fugitives, Anaerobic Reactor, and CO_2 Stripper (3.79 lb/hr).

Due to emissions increases associated with this proposal, the project is subject to S.C. Regulation 61-62.5, Standard No. 7, "Prevention of Significant Deterioration (PSD)". This regulation is equivalent to the Federal Prevention of Significant Deterioration of Air Quality regulations in Title 40 Code of Federal Regulations (CFR) Section 52.21. Pursuant to these regulations, new major stationary sources and modifications to major stationary sources of air pollution must demonstrate that they will not significantly deteriorate the air quality in their region. BPCR has potential emissions of VOC and CO, which exceed the significance levels allowed in this regulation. The PSD review was conducted for VOC and CO and includes a Best Available Control Technology (BACT) determination and Ambient Air Impact Analyses.

BPCR has submitted a revision to the PSD to change the method of operation of the #1 OX Unit. The facility has three (3) overhead condensers on its #1 Ox Unit Reactor, of which the facility currently draws a solvent/water mixture from Condensers 2 and 3. This mixture is sent to the dehydration tower (DHT), equipment ID BT-701, and the low pressure absorber (LPA), equipment ID BT-603, for solvent recovery. The facility is proposing to draw from all three condensers, as this provides better solvent and catalyst recovery, and a more stable operation. This in turns provides a significant operational savings annually. The facility is also requesting to increase the CO BACT limit for #1 OX LPA (BT-603) from 4.1 lb/hr to 14 lb/hr, based on a 30-day rolling average.

In addition to the above-mentioned modification, the facility proposes to voluntarily decrease the CO BACT limit for the high pressure vent gas treatment system (HPVGTS) from 87.9 lb/hr to 72.0 lb/hr, based on a 30-day rolling average. This change, in effect, reduces facility wide CO emissions 6 lb/hr and 26.3 tpy.

The changes to these two CO BACT limits require revising the PSD construction permit 0420-0029-CU and the associated preliminary. Only the portions of these three documents affected by these changes will be revised. The documents will also have general updates due to template changes.

B. Regulatory Applicability

The increased production capacity results in potential emissions that exceed the PSD significant thresholds. By virtue of the proposed increase, this project is subject to review under the following standards in S.C. Regulation 61-62 and Federal standards:

- SC Regulation 61-62.5, Standard No. 2 “Ambient Air Quality Standards”
- SC Regulation 61-62.5, Standard No. 3 “Waste Combustion and Reduction”
- SCC Regulation 61-62.5, Standard No. 4 “Emissions from Process Industries”
- SC Regulation 61-62.5, Standard No. 7 “Prevention of Significant Deterioration”
- SC Regulation 61-62.60 “South Carolina Designated Facility Plan and New Source Performance Standards”
- SC Regulation 61-62.61 “National Emission Standards for Hazardous Air Pollutants (NESHAPs)”
- S.C. Regulation 61-62.63 “NESHAPs for Source Categories”
- 40 CFR 60, Subpart A “Standards of Performance for New Stationary Sources - General Provisions”
- 40 CFR 60, Subpart Db “Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units”
- 40 CFR 60, Subpart VV “Standard of Performance for Equipment Leaks of VOC in Synthetic Organic Chemical Manufacturing Industry (SOCMI) for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006”
- 40 CFR 60, Subpart VVa “Standard of Performance for Equipment Leaks of VOC in Synthetic Organic Chemical Manufacturing Industry (SOCMI) for which Construction, Reconstruction, or Modification Commenced After November 7, 2006”
- 40 CFR 60, Subpart III “Standard of Performance for VOC Emissions from SOCMI Air Oxidation Unit Processes”
- 40 CFR 60, Subpart NNN “NSPS for VOC Emissions from SOCMI Distillation Operations”
- 40 CFR 60, Subpart IIII “NSPS for Stationary Compression Ignition Internal Combustion Engines”
- 40 CFR 61, Subpart FF “National Emission Standards for Benzene Waste Operations”
- 40 CFR 63, Subpart A “General Provisions”
- 40 CFR 63, Subpart F “National Emission Standards for Organic Hazardous Air Pollutants (NESHAPs) from the SOCMI”
- 40 CFR 63, Subpart G “NESHAPs From the SOCMI Process Vents, Storage Vessels, Transfer Operations, and Wastewater”
- 40 CFR 63, Subpart H “NESHAPs for Equipment Leaks”
- 40 CFR 63, Subpart ZZZZ “National Emission Standards for Hazardous Air Pollutants

(NESHAPs) for Stationary Reciprocating Internal Combustion Engines (RICE)"

- 40 CFR 63, Subpart DDDDD "NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters"
- 40 CFR Part 64 "Compliance Assurance Monitoring (CAM)"

III. Detailed Process Description

BPCR is a chemical manufacturing facility located in Wando, South Carolina that produces purified terephthalic acid (PTA). PTA is a white, inert powder used to make polyester fibers, bottles, and films. The major raw materials in the production of PTA are Paraxylene (PX), acetic acid, caustic soda, and hydrogen. Plant operation consists mainly of: 1) utilities 2) production of crude TA, 3) purification into PTA, 4) product loading/shipping, and 5) waste treatment along with some additional areas at the plant. There are two units that manufacture PTA: Cooper River #1 (CR#1), which consists of the #1 Oxidation (OX) Unit and the #1 PTA Unit; and Cooper River #2 (CR#2), which consists of the #2 Oxidation (OX) Unit and the #2 PTA Unit. The #1 and #2 OX Units produce crude TA and the #1 and #2 PTA Units purify the crude TA, to make PTA.

<u>#1 & #2 Oxidation Units</u>
In each Oxidation (OX) unit, a BPCR proprietary process is used for the catalytic liquid phase air oxidation of paraxylene (PX) to produce crude terephthalic acid (TA). Acetic acid (HAC) and catalyst solution are mixed in a feed mix drum. The feed mix from the drum, PX (by direct injection), and air from the process air compressors are continuously fed to the reactors. Exothermic heat from the reaction is removed by flashing off, and then condensing the boiling reaction solvent. A portion of this condensate is withdrawn to control the water concentration in the reactor and the remainder is refluxed back to the reactor.

Reactor effluent is depressurized and cooled to filtering conditions in a series of crystallizers. Air is fed to the first crystallizer for additional reaction. The crystallizer temperatures are controlled by allowing a portion of the reaction solvent to flash off. The crystallizer vent streams are sent to the dehydration tower (DHT) or the high pressure absorber (HPA) for recovery of valuable materials. The DHT also removes water formed in the reaction. The DHT is an azeotropic distillation system where the vent streams from the system are sent thru two-stage scrubbing. This two-stage scrubbing recovers PX and HAC before being vented to the atmosphere through the LPA. The excess reaction water removed by the DHT system is sent to wastewater treatment. The crystallizer precipitate, TA, is recovered by filtration and finally dried. The dried TA solids are conveyed to the OX intermediate storage silos (TA silos) and stored for additional processing in the PTA unit.

The off-gas from the OX reactors is sent through a recovery device, the HPA, before being sent to a control device, the high pressure vent gas treatment system (HPVGTS) in which CO, VOC, and HAP are nearly totally destroyed and emitted to the atmosphere. The HPVGTS reactor contains catalyst bricks that are routinely changed out based on their activity and mechanical condition. Further processing in the OX unit is required to recover and purify HAC from the reactor outlet, crystallizer solvent withdrawal streams, and also from the un-recycled mother liquor stream.

#1 & #2 Purified Terephthalic Acid Units

The purified terephthalic acid (PTA) unit is also a continuous operation. Crude terephthalic acid (TA) is fed from the TA silos to the feed slurry drum to produce a slurry of TA crystals and water. The slurry is heated to dissolve the TA and then the slurry enters the hydrogenation reactor where it reacts to convert the impurities into a form that can be separated from the product. The PTA reactor catalyst is routinely changed out based on its activity and mechanical condition. After reaction, the solution goes through a cycle of lowering the pressure and cooling to crystallize the PTA. A portion of the aromatic acids in the mother liquor are recovered by cooling and filtering the mother liquor; the aromatic acids are recycled back to the OX reaction unit.

The crystallized PTA is recovered from the mother liquor by separation in the filtration section of the unit. The final product is dried and transferred to the PTA day silos and then to the PTA product storage silos.

Product Loading and Shipping

The PTA storage system is comprised of six large silos that are used to manage product transfers, packaging, loading and shipping. Shipping personnel package the product from the large silos into various containers and ship it to the customers.

IV. Significant Emission Rates

As shown in Table IV-1, this project exceeds the significant threshold as defined under PSD for CO and VOC emissions. Emissions calculations for the modified units were based on actual-to-potential test to determine if there was a significant emissions increase.

Table IV-1. PSD Applicability Analysis

Pollutant	Controlled Emissions Increase	PSD Significant Threshold	Significant Increase?
	TPY	TPY	
PM	7.0	25	No
PM_{10}	6.6	15	No
$PM_{2.5}$	5.8	10	No
SO_2	0.2	40	No
NO_X	27.8	40	No
CO	618.5	100	Yes
VOC	200.3	40	Yes
CO_2e	17,300	75,000	No

V. Best Available Control Technology (BACT) Determination

A. BACT Requirement

BACT is defined as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant, taking into account energy, environmental, and economic impacts." As per S.C. Regulation 61-62.5, Standard No. 7, the BACT requirement applies to each individual new or modified affected emissions unit and pollutant emitting activity at which a net emissions increase would occur. In no case can the application of BACT result in emissions of any pollutant which would exceed emissions allowed under any applicable standard under 40 CFR 60 *New Source Performance Standard (NSPS)*, 61 *NESHAP* or 63 *NESHAP for Source Categories*.

Chapter B of the draft *New Source Review Workshop Manual* (October 1990) defines the BACT determination process as a 5-step process.

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

Opacity is not considered to be a PSD pollutant and therefore, opacity itself does not require a BACT evaluation and establishment of a BACT limit. However, BACT can include the use of visible emission limitations or work practice standards for regulated PSD pollutants. Opacity limits have been included in the draft permit as required by State and Federal regulations. BACT cannot be less stringent than an applicable NSPS or NESHAP as outlined in 40 CFR 60, 61, and 63.

The primary resource for establishing BACT is the RACT/BACT/LAER Clearinghouse (RBLC) on the Technology Transfer Network (TTN) maintained by the EPA. To establish BACT for a PSD source, state regulatory agencies query the RBLC. This database contains information about available control technologies for specific industry sources and lists the limits that other pollution control agencies have established for similar source types.

BAQ queried the RBLC for all similar process types and NSR applicable pollutants. An RBLC advanced search was queried using a standard industrial classification (SIC) code of 2869. In addition to the RBLC, the following sources were reviewed: EPA Control Technology documents (i.e. Air Pollution Control Technology Fact Sheets), NSPS and NESHAP regulations for SOCMI processes, South Coast Air Quality Management District BACT, the California Air Resources Board BACT Clearinghouse, an internet search for similar facilities, a general internet search for VOC and CO emission controls, and operating permits for existing facilities with similar processes.

BPCR queried the RBLC using process types 64.000, 64.003 and 64.999, SOCMI production, process vents, and organic chemical production. Other resources of control technology reviewed were the *EPA Air Pollution Control Technology Fact Sheets*, *EPA Air Pollution Control Cost Manual Sixth Edition* (EPA/452/B-02-001, January 2002), and the applicable NSPS and NESHAP standards. BPCR's queries did not find any control technologies that apply directly to the purified terephthalic acid (PTA) manufacturing process. BPCR also looked at sister facilities located internationally, and found that the conventional control technologies used are the same used at this facility. The sister facilities with new/modern technologies are not compatible and are not feasible to add to the conventional technology. BPCR does not have any data on control technologies for PTA facilities not owned by or joint venture with BP Amoco.

The following control technologies were found to reduce VOC and/or CO emissions. These control technologies will be used throughout the BACT Determination, but the descriptions will not be repeated for each determination.

- **Thermal Oxidizer (TO)** –A TO is a control technology that uses high temperature combustion to control gaseous pollutants, such as VOCs, HAPs and CO. Fuel and air are added to a combustion chamber through which the exhaust gases pass to maintain a high minimum operating temperature, usually 1200 – 1700 °F, and combusts the VOC into carbon dioxide (CO_2) and water (H_2O). This technology typically has a control efficiency of 99+ percent for VOCs and 95+ percent for CO.
- **Regenerative Thermal Oxidizer (RTO)** – An RTO is a control technology that is similar to a TO in the manner it controls gaseous pollutant emissions. The difference between an RTO and a TO is the increased energy efficiency an RTO achieves. This efficiency is attained by storing heat from hot exhaust gases in ceramic media as the process stream enters and exits the combustion chamber. The cooler inlet process stream then recovers the heat from the ceramic media. This technology typically has a control efficiency of 95 to 99 percent for VOCs and 98+ percent for CO.
- **Recuperative Thermal Oxidizer (RCO)** – An RCO is a control technology that is similar to a TO in the manner it controls gaseous pollutant emissions. The difference between an RCO and a TO is the increased energy efficiency that an RCO achieves. This is achieved by adding a primary and/or secondary heat exchanger within the system, where the heat exchanger(s) preheat(s) the incoming vent stream by recuperating heat from the exiting treated exhaust stream. This technology typically has a control efficiency of 90 to 99 percent for VOCs and 98+ percent for CO.
- **Catalytic Thermal Oxidizer (CTO)** – A CTO is a control technology that oxidizes (combusts) gaseous pollutants at temperatures several hundred degrees lower than a TO, RTO, and RCO (typically 500 - 1,000 °F). This is achieved by using a precious-metal catalyst,

usually in the form of a bed. A catalyst is a substance used to accelerate the rate of a chemical reaction (combustion), allowing the reaction (combustion) to occur at a much lower temperature. The lower temperatures reduce the amount of supplemental heat required for the process. This technology typically has a control efficiency of 95+ percent for VOCs and 95+ percent for CO.

- **Absorber/Wet Scrubber** – An absorber/wet scrubber is a control technology that removes particulate and/or gaseous pollutants from industrial exhaust streams via contact of contaminants with a liquid absorbing/scrubbing solution. The process uses rapid gas absorption into the scrubbing solution to remove the contaminants. The solution is usually water, or it can be other liquids that specifically target certain compounds. Typically gas enters the bottom of the absorber and passes upward through the scrubbing solution that is sprayed into the top of the scrubber. The scrubbed gas then goes through a mist eliminator where entrained liquid droplets are removed before exhausting to the atmosphere. The scrubber solution is collected in the bottom of the tower where most of the scrubbing solution is recycled to the top of the tower. This technology typically has a control efficiency of 90+ percent for VOCs, but does not control CO.
- **Adsorber –** An adsorber is a control technology that removes pollutants by adhesion to a high surface solid material (adsorbent), such as activated carbon. An adsorber can be used to capture gas or liquid contaminants. The adsorbed material can then be desorbed, removed by heat or vacuum, and reused. This technology typically has a control efficiency of 98 percent for VOCs, but does not control CO.
- **Condenser –** A condenser is a control technology that removes a pollutant by converting the pollutant from a gas to a liquid. This can be done by either cooling, or increasing the pressure of the gas. The condensed liquid can be recovered or recycled. Often, condensers are heat exchangers, having various designs and sizes. This technology typically has a control efficiency of 50 - 90 percent depending on the concentration of VOC compounds present in the gas stream, but does not control CO emissions.
- **Flare –** A gas flare, also known as a flare stack, is a control technology that uses a high temperature (up to 2000 °F) open air flame to burn off flammable gases such as VOCs. The vent stream being combusted must have a heating value greater than 300 British thermal units/standard cubic feet (Btu/scf) to maintain combustion, or a supplemental fuel must be added to meet the minimum of 300 Btu/scf. The control requirements in 40 CFR 60.18 states a flare shall only be used as a control device if the vent stream being combusted has a net heating value of at least 200 Btu/scf. to prevent blowing out the flare flame. This technology typically has a control efficiency of 95+ percent for VOCs. A flare is not a good option to use for control of CO emissions because it can produce as much CO as it controls.
- **Boiler –** A boiler is an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process

wherein fuel and/or oxidizer feed rates are controlled. A boiler can be used a control device where waste gas streams are fed directly into the boiler flame, essentially operating as thermal oxidizer. This technology typically has a control efficiency of 99+ percent for VOCs and 95+ percent for CO.

- **Biofiltration** – Biofiltration is a control technology that uses living material (microorganisms) to metabolize or breakdown organic pollutants in contaminated air streams. The contaminated air stream is slowly pumped through a packed bed or other filter media, and pollutants are absorbed into a thin layer of moisture, called biofilm, surrounding the particles that make up the filter media. Biological degradation of pollutants occurs in this biofilm, resulting in the byproducts of CO_2 and H_2O. Biofilters are very sensitive to temperature and moisture content, and work best with low VOC concentrations (<1,000 ppm). This technology typically has a control efficiency of 90+ percent for VOCs, but does not control CO.
- **Good Combustion Practices** – Good combustion practices are methods used to maintain combustion equipment (such as periodic burner tune-ups) and operate within recommended combustion air and fuel ranges (i.e. good air/fuel mixing in combustion zone). This promotes efficient and complete combustion of fuel, which results in reduction of combustion emissions.
- **Good Design and Operating Practices** – Good design and operating practices are opportunities for a stationary source to reduce or eliminate pollutants through cost-effective changes in production, operation and raw materials use. Good design practice is the planning of processes or equipment that either inherently lowers pollutants, or that minimizes emissions. Good operating practices are the use of methods and procedures (i.e.; environmental management systems) to minimize emissions. The intent of these practices is to minimize the formation of CO, rather than use add-on controls to reduce or eliminate CO emissions on the "back end" of the process(es).

The proposed project includes modified emission units that are subject to PSD review and will have VOC and CO emissions increases requiring a BACT analysis. The table below represents these emission units, with associated equipment, and the estimated potential VOC and CO emissions from these emission units.

Table V.A-1: Potential VOC & CO Emissions*

Emission Unit	Equipment (Equipment ID)	VOC Emissions		CO Emissions	
		lb/hr	tpy	lb/hr	tpy
#1 OX	High Pressure Absorber (BT-401)	234	1024.9	1758	7700.7
	Low Pressure Absorber (BT-603)	9.6	42	14.0	61.3
	Fugitives	21.5	94.4	N/A	N/A
	Emergency Generator (BM-1201)	0.07	0.003	0.59	0.03

Table V.A-1: Potential VOC & CO Emissions*

Emission Unit	Equipment (Equipment ID)	VOC Emissions		CO Emissions	
		lb/hr	tpy	lb/hr	tpy
	Emergency Generator (BM-1204)	0.02	0.001	0.57	0.03
#2 OX	High Pressure Absorber (DT-111)	175	766.5	1500	6571.5
	Low Pressure Absorber (DT-302)	8.85	38.8	3.47	15.2
	HPVGTS Fired Heater (DB-1813)	0.08	0.35	1.24	5.41
	Fugitives	21.85	95.7	N/A	N/A
#1 PTA	Crystallizer Vent Scrubber (CM-301)	20	87.6	24	105.1
#2 PTA	Crystallizer Vent Scrubber (DM-601)	20	87.6	20	87.6

* Note that potential emissions are based on no add-on controls for all equipment. The only equipment that currently has controls are the High Pressure Absorbers. Fugitive emissions are based on the LDAR programs currently in place. Emergency Generator PTE's are based on 100 hours per year limit.

B. BACT for VOCs from #1 and #2 Oxidation (OX) Unit High Pressure Absorbers

Each OX Unit's reactor will send overheads to an existing scrubber to recover paraxylene (PX) and then to a recovery device (High Pressure Absorber (HPA)) to recover mainly acetic acid and any residual PX. The HPA outlets are sent to the High Pressure Vent Gas Treatment System (HPVGTS), which consists of a CTO to control VOCs, HAPs, and CO; followed by a bromine scrubber, to control methyl bromide. The VOC PTE from the #1 OX HPA is 1024.9 tons per year, and from the #2 OX HPA is 766.5 tons per year.

<u>Step 1: Identify All Available Control Technologies</u>

The following control technologies were found to reduce VOC emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Absorber/Wet Scrubber
- Carbon Adsorber
- Condenser
- Flare
- Boiler

- Biofiltration

Step 2: Technical Feasibility of Options

The use of the boiler is not technically feasible because the methyl bromide present in the waste gas streams would cause severe corrosion in the carbon steel boilers. In addition, the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, and the boiler cannot handle this.

The use of the thermal combustion options (TO, RTO, RCO, CTO, and flare) and recovery options (absorber/scrubber, carbon adsorber, and condenser) are technically feasible since they all are successfully used in similar processes. Although the addition of an absorber/wet scrubber is technically feasible, it would have a lower control efficiency than normal because the waste stream is already being controlled by a two-stage absorber system.

The biofiltration control option is technically feasible because it is successfully used in similar processes. However, it would have a lower control efficiency than normal because of the large amount of methyl bromide present. Methyl bromide is a very toxic biocide and will kill a substantial amount of the microorganisms used to biodegrade the VOCs.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their VOC emission reduction potential (% control efficiency) for the HPA.

Table V.B-1: Control Technology Rankings for HPA VOC BACT

Control Option	Efficiency (%)
TO	99
RTO	99
RCO	99
CTO (existing)	98
Flare	98
Carbon Adsorption/TO	96
Condenser	60
Absorber/Wet Scrubber	50
Biofiltration	35

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.B-2: Summary of #1 & #2 OX Units HPA VOC BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO	1,014.7	$29,021,335	$28,600	11,306,341	No
RTO	1,014.7	19,211,876	18,935	1,002,328	No
RCO	1,014.7	23,432,003	23,100	5,563,302	No
CTO (Existing)	1,004.4	567,782	519	360,206	No
Flare	1,004.4	19,344,753	19,260	2,072,818	No
Carbon Adsorption/TO*	983.9	5,437,736	5,530	28,257	No
Condenser	615	1,772,038	3,458	0	No
Absorber/Wet Scrubber	512.5	271,303	441	0	No
Biofiltration	358.8	17,495,731	48,762	7,578	No

* The Annualized Operating Cost for Carbon Adsorption/TO control is less than the TO control option because the Carbon Adsorption/TO control option uses much less supplemental fuel due to the higher concentration of VOCs from the Adsorber.

Economic Impact Analysis

As shown in Table V.B-2 above, the use of a TO, RTO, RCO, or Flare as a control option is not as cost effective as the existing CTO, which either has the same or relatively same VOC control efficiency (98 to 99%).

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no unusual energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste. Operation of the condenser would create large quantities of liquid waste that will need to be treated prior to discharge. The operation of the absorber/wet scrubber option would generate large quantities of wastewater that will need to be treated prior to discharge.

Step 5: Select BACT Controls and Limits

BACT has been determined to be the existing CTOs. Using the control efficiency of the existing CTOs, the VOC limit for the #1 and #2 OX HPA has been determined to be 4.70 and 3.50 lb/hr, respectively, based on a 3-hour block average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will monitor each CTO inlet and outlet temperature, while processes venting to each CTO are in operation. These parameters will be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period (midnight to midnight), and shall be averaged together for a daily reading. The parameters used to demonstrate compliance will be the daily average inlet temperature and the daily average reactor delta temperature of the CTO. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met:

- The daily average for a parameter is outside the approved monitoring range.
- The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.

A source test to determine VOC emission rates from each CTO is required within 180 days after startup and every three years thereafter. If the catalyst is replaced in a CTO, a new source test schedule shall be required as follows: A source test for VOC and CO emissions shall be conducted within 90 days after changing the catalyst in a CTO, and every three years thereafter.

In most cases, a source test for control efficiency is a BACT required monitoring parameter for control devices. However, through discussions with BPCR, a control efficiency test will not be required for the CTOs because historical testing has shown that outlet stream emissions (and sometimes inlet stream emissions) are at or below detection levels, making it difficult to measure efficiencies.

C. BACT for VOCs from #1 and #2 Oxidation (OX) Unit Low Pressure Absorbers

Each Oxidation (OX) Unit utilizes an existing recovery device (Low Pressure Absorber (LPA)) to recover acetic acid from several process streams. The acetic acid, which acts as a solvent in the process, is purified and reused in the process. This recycling of the solvent reduces purchase costs. Part of this project is to optimize acetic acid recovery. These absorbers are used as recovery devices and currently do not have controls. The VOC PTE from the #1 OX LPA is 42 tons per year, and from the #2 OX LPA is 38.8 tons per year.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce VOC emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Absorber/Wet Scrubber
- Carbon Adsorber
- Condenser
- Flare
- Boiler
- Biofiltration

Step 2: Technical Feasibility of Options

The use of the boiler is not technically feasible because the methyl bromide present in the waste gas streams would cause severe corrosion in the carbon steel boilers. In addition, the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, and the boiler cannot handle this.

The use of the thermal combustion options (TO, RTO, RCO, CTO, and flare) and recovery options (absorber/wet scrubber, carbon adsorber, and condenser) are technically feasible since they all are successfully used in similar processes. Although the addition of an absorber/wet scrubber is technically feasible, it would have a lower control efficiency than normal because the waste stream is already being controlled by a two-stage absorber system.

The biofiltration control option is technically feasible because it is successfully used in similar processes. However, it would have a lower control efficiency than normal because of the large amount of methyl bromide present. Methyl bromide is a very toxic biocide and will kill a substantial amount of the microorganisms used to biodegrade the VOCs.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their VOC emission reduction potential (% control efficiency).

Table V.C-1: Control Technology Rankings for LPA VOC BACT

Control Option	Efficiency (%)
TO	99
RTO	99
RCO	99
CTO (New)	98
CTO (Existing)	98
Flare	98
Carbon Adsorption/TO	96
Biofiltration	57
Refrigerated Condenser	55
Absorber/Wet Scrubber	50

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.C-2: Summary of #1 & #2 OX Units LPA VOC BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO	41.6	$535,524	$12,873	$344,412	No
RTO	41.6	464,581	11,168	188,922	No
RCO	41.6	500,627	12,034	97,422	No
CTO (New)*	41.2	375,878	9,123	100,324	No
CTO (Existing)	41.2	1,062,446	25,788	625,604	No
Flare	41.2	2,925,574	71,010	2,728,146	No
Carbon Adsorber/TO	40.4	491,516	12,166	14,811	No
Biofiltration	23.9	198,756	9,402	7,600	No
Refrigerated Condenser	23.1	367,259	15,900	17,050	No
Absorber/Wet Scrubber	21.0	425,373	20,233	3,789	No

* The Annualized Operating Cost for the New CTO is less than the Existing CTO because the New CTO would operate at a lower pressure and be much smaller since it would be only controlling emissions from the LPA.

Economic Impact Analysis

The control technologies listed in Table V.C-2 above are not cost effective. All of the control technologies would require additional equipment (i.e. fan, blower, compressor) to raise the pressure of the LPA outlet streams. The use of a direct flame oxidizer option (TO, RTO, or RCO) would also not be cost effective due the need to have stainless steel metallurgy. This is recommended for streams containing halogen compounds (methyl bromide in this case) where there can be formation of highly corrosive acid gases. The use of absorber/wet scrubber is also not cost effective because of the low VOC concentration of the LPA outlet stream.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no additional energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste. Operation of the condenser would create large quantities of liquid waste that will need to be treated prior to discharge. The operation of the absorber/wet scrubber option would generate large quantities of wastewater that will need to be treated prior to discharge.

Step 5: Select BACT Controls and Limits

Because none of the control options were deemed feasible, a VOC limit, along with monitoring, recordkeeping, and reporting was set as BACT. Using the recovery efficiency of the LPAs, the VOC limit for the #1 and #2 OX LPA has been determined to be 9.60 and 8.85 lb/hr, respectively, based on a 3-hour block average, each. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will monitor LPA top liquid flow and LPA top temperature, while processes venting to the LPA are in operation. These parameters will be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period, and shall be averaged together for a daily reading. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the

Department indicating such. An excursion shall be deemed to have occurred if either of the following are met:

- The daily average for a parameter is outside the approved monitoring range.
- The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.

A source test to determine VOC emission rates from the LPA units is required within 180 days after startup, and every 3 years thereafter.

D. BACT for VOCs from #1 and #2 Oxidation (OX) Unit Fugitives

Each Oxidation (OX) Unit has equipment that emits fugitive VOC emissions from valves, flanges, drains, vents, pumps, relief valves, etc. Currently the OX units' fugitive emissions are being minimized through various leak detection and repair (LDAR) programs, to include NSPS VV, a modified version of NSPS VV, and the HON. For the BACT analysis, BPCR used the NSPS VV LDAR program as the baseline, and an upgrade to either a NSPS VVa or a HON LDAR will be considered. The fugitive VOC PTE and baseline from the #1 OX unit is 94.4 tons per year, and from the #2 OX unit is 95.7 tons per year.

Step 1: Identify All Available Control Technologies

An LDAR program was the only control technology found to apply to fugitive emissions. An LDAR program is a work practice designed to identify leaking equipment so that emissions can be reduced through repairs. A component that is subject to LDAR requirements must be monitored at specified, regular intervals to determine whether it is leaking or not. Any leaking component must be repaired or replaced within a specified time frame. LDAR programs are governed by several different regulations, including National Emission Standards for Hazardous Air Pollutant (NESHAPs), New Source Performance Standards (NSPS) Subpart VV/VVa, the Hazardous Organic NESHAP (HON), Maximum Achievable Control Technology (MACT), State Implementation Plans (SIPs), the Resource Conservation and Recovery Act (RCRA), and other state or local requirements (i.e. - Consent Decrees). Typically a facility uses a combination of LDAR programs, as BPCR is currently.

Step 2: Technical Feasibility of Options

LDAR programs are a widely accepted control technology used to reduce fugitive VOC emissions in chemical plants, making them technically feasible for BPCR.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their VOC emission reduction potential (Effectiveness Factor). The table below uses two example components (valve and pump) to compare effectiveness of each control option.

Table V.D-1: Control Technology Rankings for OX Unit Fugitives VOC BACT

CONTROL OPTION	Valves - Light Liquid Service Control Effectiveness (%)	Pumps - Light Liquid Service Control Effectiveness (%)
HON MACT LDAR Program	88	75
NSPS VVa LDAR Program	88	71
LDAR VV Program (existing)	61	69

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.D-2: Summary of #1 & #2 OX Units Fugitive VOC BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)
Upgrade NSPS VV to HON	146.0	$72,600	$497
Upgrade NSPS VV to VVa	46.4	59,640	1,285

Economic Impact Analysis
As shown in Table V.B-2 above, the top control option is also the most cost effective.

Energy Impact Analysis
Upgrading to the HON LDAR program does not contribute to any unusual energy penalties or benefits.

Environmental Impact Analysis
Upgrading to the HON LDAR program does not contribute to any adverse environmental impacts.

Step 5: Select BACT Controls and Limits

BACT has been determined to be an upgrade to the HON LDAR program (covered under Regulation 40 CFR 63 Subpart H) for all fugitive VOC emissions in the #1 and #2 OX Units. All VOCs will be treated as HAPs for determining monitoring applicability. These limits shall apply at all times including during startup, shutdown, and malfunction. Monitoring, recordkeeping, and reporting will be in accordance with the HON LDAR (63.160 through 60.182). Testing shall be performed as per 40 CFR 63.180.

E. BACT for VOCs from #1 and #2 PTA Crystallizer Vent Scrubbers (CVS)

Each Purified Terephthalic Acid (PTA) Unit utilizes crystallizers to purify the crude TA. These crystallizers flash off liquids in order to control the temperature of the crystallizers. The vapor stream from each crystallizer is sent to a vent scrubber to remove particulate matter (PM), which is mostly PTA. The scrubbed vapor from the CVS, consisting of mostly water (99%) and small amounts of VOCs, is vented to the atmosphere. The VOC PTE from the #1 PTA and #2 PTA CVS is 87.6 tons per year, each, based on a 3-hour block average. These limits shall apply at all times including during startup, shutdown, and malfunction.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce VOC emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Absorber/Wet Scrubber
- Carbon Adsorber
- Condenser
- Flare
- Boiler
- Biofiltration

Step 2: Technical Feasibility of Options

The operation of a flare is not technically feasible, because the exhaust streams from the crystallizers is 99% water and have very low heating values (less than 5 Btu/scf). The operation of a carbon adsorber is not technically feasible, because at moisture contents over 50%, the water molecules compete with the VOC molecules for adsorption. This significantly lowers the capacity, and therefore the efficiency, of the adsorber system. The use of the boiler is not technically feasible because the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, and the boiler cannot handle this.

The use of the remaining control options is technically feasible since they all are successfully used in similar processes. The control efficiency of the biofiltration control option would be lower than typical due to the presence of VOC compounds that are not water soluble. Additionally, the large amounts of water vapor in the inlet stream would require dehumidification prior to being sent to the biofiltration and absorber/wet scrubber control options.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their VOC emission reduction potential (% control efficiency).

Table V.E-1: Control Technology Rankings for Crystallizer Vent Scrubber VOC BACT

Control Option	Efficiency (%)
TO	99
RTO	99
RCO	99
CTO (New)	98
CTO (Existing)	98
Absorber/Wet Scrubber	90
Biofiltration	70
Condenser	60

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.E-2: Summary of CVS VOC BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO	86.7	$1,606,826	$18,533	$1,420,194	No
RTO	86.7	1,107,759	12,780	840,446	No
RCO	86.7	1,772,897	20,450	1,342,851	No
CTO (New)*	85.8	1,214,489	14,155	913,344	No
CTO (Existing)	85.8	1,748,926	20,384	1,428,322	No
Absorber/Wet Scrubber	78.8	717,878	9,110	11,366	No
Biofiltration	65.7	495,525	7,542	9,472	No
Condenser	52.6	438,446	8,335	18,944	No

* The Annualized Operating Cost for the New CTO is less than the Existing CTO because the New CTO would operate at a lower pressure and be much smaller since it would be only controlling emissions from the LPA.

Economic Impact Analysis

As shown in Table V.E-2 above, all the control options are not cost effective. All of the control technologies would require additional equipment (i.e. fan, blower) to raise the pressure of the CVS outlet streams. Use of a combustion control option (TO, RTO, RCO, CTO) would require large amounts of supplemental fuel and air to incinerate the waste because of the large volume of inert gas in the CVS outlet streams. Use of the existing CTO would require a compressor (much more costly than a fan/blower) to provide the pressure required to route the CVS outlet stream to the HPVGTS. Use of the biofiltration and absorber/wet scrubber control options would require a dehumidification system to remove the large volume of water from the CVS outlet streams, which also increases cost.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no additional energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste. Operation of the absorber/wet scrubber or condenser would create large quantities of liquid waste that will need to be treated prior to discharge.

Step 5: Select BACT Controls and Limits

Because none of the control options were deemed feasible, a VOC limit, along with monitoring, recordkeeping, and reporting was set as BACT. Using the uncontrolled emissions of the CVS, the VOC limit for the #1 and #2 PTA CVS has been determined to be 20.0 lb/hr, each, based on a 3-hour block average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will be required to calculate and maintain hourly VOC emissions. Hourly VOC emissions shall be calculated on a 3-hour block average. Reports of the calculated values shall be submitted semiannually, and maintained on site for a period of at least 5 years.

A source test to determine VOC emission rates from each CVS is required within 180 days after startup, and every 3 years thereafter.

F. BACT for CO from #1 and #2 Oxidation (OX) Unit High Pressure Absorbers

As discussed in the VOC BACT analysis for the HPAs, each OX Unit utilizes the HPA as a recovery device to reclaim mainly acetic acid, and residual paraxylene. CO is created as byproduct from the unwanted side reaction of oxygen and acetic acid in the reactor. The HPA outlets are sent to the High Pressure Vent Gas Treatment System (HPVGTS), which consists of a Catalytic Thermal Oxidizer (CTO), followed by a bromine scrubber. The HPVGTS controls VOCs, HAPs, and CO. The CO PTE from the #1 OX HPA is 7700 tons per year, and from the #2 OX HPA is 6571.5 tons per year.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce CO emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Flare
- Boiler
- Good Combustion Practices

Step 2: Technical Feasibility of Options

The use of a flare is not technically feasible, since more CO emissions are created, from the burning of required supplemental fuel, than destroyed. Good combustion practices are not technically feasible because the HPA is not a combustion process. The use of the boiler is not technically feasible because the methyl bromide present in the waste gas streams would cause severe corrosion in the carbon steel boilers. In addition, the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, which the boiler cannot handle. The use of the thermal combustion options (TO, RTO, RCO, and CTO) is technically feasible since they all are successfully used in similar processes.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their CO emission reduction potential (% control efficiency).

Table V.F-1: Control Technology Rankings for HPA CO BACT

Control Option	Efficiency (%)
TO	95
RTO	95
RCO	95
CTO (Existing)	95

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.F-2: Summary of #1 & #2 OX Units HPA CO BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO*	7,160.6	$29,021,335	$4,060	11,306,341	No
RTO*	7,288.6	19,211,976	2,636	1,362,534	No
RCO*	7,231.6	23,400,467	3,236	5,923,508	No
CTO (Existing)**	7,297.6	567,782	78	360,205	No

* These control options have CO generated from combustion of supplemental fuel and VOCs in the waste gas stream, slightly off-setting the CO reduction.

** This control option has CO generated from combustion of VOCs in the waste gas stream, slightly off-setting the CO reduction.

Economic Impact Analysis

As shown in Table V.F-2 above, the use of a TO, RTO, or RCO control option is not as cost effective as the existing CTO, which has the same CO control efficiency of 95%.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no unusual energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste.

Step 5: Select BACT Controls and Limits

BACT has been determined to be the existing CTO's. Using the control efficiency of the existing CTOs, the CO limit for the #1 and #2 OX HPA has been determined to be 72.0 and 75.0 lb/hr, respectively, based on a 30-day rolling average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will monitor each CTO inlet and outlet temperature, while processes venting to each CTO are in operation. These parameters will be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period (midnight to midnight), and shall be averaged together for a daily reading. The parameters used to demonstrate compliance will be the daily average inlet temperature and the daily average reactor delta temperature of the CTO. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met:

- The daily average for a parameter is outside the approved monitoring range.
- The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.

A source test to determine VOC emission rates from each CTO is required within 180 days after startup and every three years thereafter. If the catalyst is replaced in a CTO, a new source test schedule will be required as follows: A source test for VOC and CO emissions shall be conducted within 90 days after changing the catalyst in a CTO, and every three years thereafter.

In most cases, a source test for control efficiency is a BACT required monitoring parameter for control devices. However, through discussions with BPCR, a control efficiency test will not be required for the CTOs because historical testing has shown that outlet stream emissions (and sometimes inlet stream emissions) are at or below detection levels, making it difficult to measure efficiencies.

G. BACT for CO from #1 and #2 Oxidation (OX) Unit Low Pressure Absorbers

As discussed in the VOC BACT analysis for the LPAs, each OX Unit utilizes the LPA as a recovery device to reclaim acetic acid. CO is created as byproduct from the unwanted side reaction of oxygen and acetic acid in the reactor. The LPAs do not recover or control any CO; and therefore, all CO is emitted to the atmosphere. There are currently no controls on the LPAs. The CO PTE from the #1 OX LPA is 61.3 tons per year, and from the #2 OX LPA is 15.2 tons per year.

<u>Step 1: Identify All Available Control Technologies</u>

The following control technologies were found to reduce CO emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Flare
- Boiler
- Good Combustion Practices
- Good Design and Operating Practices

<u>Step 2: Technical Feasibility of Options</u>

The use of a flare is not technically feasible, since more CO emissions are created, from the burning of required supplemental fuel, than destroyed. Good combustion practices are not technically feasible because the LPA is not a combustion process. The boiler is not technically feasible because the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, which the boiler cannot handle. The use of the thermal combustion options (TO, RTO, RCO, and CTO) is technically feasible since they all are successfully used in similar processes.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their CO emission reduction potential (% control efficiency).

Table V.G-1: Control Technology Rankings for LPA CO BACT

Control Option	Efficiency (%)
TO	95
RTO	95
RCO	95
CTO (New)	95
CTO (Existing)	95

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.G-2: Summary of #1 OX Units LPA CO BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO	58.2	504,787	8,673	313,676	No
RTO	58.2	352,810	6,062	92,646	No
RCO	58.2	408,407	7,017	105,558	No
CTO (New)*	58.2	337,895	5,806	96,708	No
CTO (Existing)	58.2	1,170,243	20,107	625,604	No

* The Annualized Operating Cost for the New CTO is less than the Existing CTO because the New CTO would operate at a lower pressure and be much smaller since it would be only controlling emissions from the LPA.

Table V.G-3: Summary of #2 OX Units LPA CO BACT Impact Analysis					
Control Option	**Emission Reduction (tpy)**	**Annualized Operating Cost ($)**	**Average Cost Effectiveness ($/ton)**	**Increased Energy Usage ($/yr)**	**Adverse Environmental Impacts?**
TO	17.1	535,524	31,317	329,068	No
RTO	17.1	464,581	27,168	188,922	No
RCO	17.1	500,627	29,276	97,422	No
CTO (New)*	17.1	375,828	21,978	132,869	No
CTO (Existing)	17.1	1,062,446	62,131	1,428,322	No

* The Annualized Operating Cost for the New CTO is less than the Existing CTO because the New CTO would operate at a lower pressure and be much smaller since it would be only controlling emissions from the LPA.

Economic Impact Analysis

The technologies listed in Tables V.G-2 and V.G-3 above are not cost effective. All of the control technologies would require additional equipment (i.e. fan, blower) to raise the pressure of the LPA outlet streams. The use of a direct flame oxidizer option (TO, RTO, or RCO) would also not be cost effective due the need to have stainless steel metallurgy. This is recommended for streams containing halogen compounds (methyl bromide in this case) where there can be formation of highly corrosive acid gases.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no additional energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste.

Step 5: Select BACT Controls and Limits

Because none of the control options were deemed feasible, a CO limit, along with monitoring, recordkeeping, and reporting was set as BACT. Using the recovery efficiency of the LPAs, the CO limit for the #1 and #2 OX LPA has been determined to be 14.0 and 3.50 lb/hr, respectively, based on a 30-day rolling average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will be required to calculate and maintain hourly CO emissions. Hourly CO emissions shall be calculated on a 30-day rolling average. Reports of the calculated values shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years.

A source test to determine CO emission rates from the LPA units is required within 180 days after startup, and every 3 years thereafter.

H. BACT for CO from #1 and #2 PTA Crystallizer Vent Scrubbers

As discussed in the VOC BACT analysis for the CVS, each PTA Unit utilizes crystallizers to purify the crude TA. These crystallizers flash off liquids in order to control the temperature of the crystallizers. The vapor stream from each crystallizer is sent to a vent scrubber to remove particulate matter (PM), which is mostly PTA. The scrubbed vapor from the CVS consists of mostly water (99%) and small amounts of CO. The CO PTE from the #1 PTA and #2 PTA CVS is 105.1 and 87.6 tons per year, respectively.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce CO emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Flare
- Boiler
- Good Combustion Practices

Step 2: Technical Feasibility of Options

The use of a flare is not technically feasible, since more CO emissions are created, from the burning of required supplemental fuel, than destroyed. Good combustion practices are not technically feasible because the CVS is not a combustion process. The boiler is not technically feasible because the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, and the boiler cannot handle this volume. The use of the thermal combustion options (TO, RTO, RCO, and CTO) is technically feasible since they all are successfully used in similar processes.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their CO emission reduction potential (% control efficiency).

Table V.H-1: Control Technology Rankings for CVS CO BACT

Control Option	Efficiency (%)
TO	95
RTO	95
RCO	95
CTO (New)	95
CTO (Existing)	95

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.H-2: Summary of #1 & #2 PTA CVS CO BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO	99.8	$1,594,999	$15,982	$1,413,184	No
RTO	99.8	1,107,759	11,100	840,446	No
RCO	99.8	1,722,897	17,263	1,342,851	No
CTO (New)	99.8	1,214,489	12,169	913,344	No
CTO (Existing)	99.8	1,748,926	17,524	1,428,322	No

Economic Impact Analysis

The technologies listed in Table V.H-2 above are not cost effective. All of the control technologies would require additional equipment (i.e. fan, blower) to raise the pressure of the CVS outlet streams. These control options would also require large amounts of supplemental fuel and air to incinerate the waste because of the large volume of inert gas in the CVS outlet streams. Use of the existing CTO would require a compressor (much more costly than a fan/blower) to provide the pressure required to route the CVS outlet streams to the HPVGTS.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no unusual energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste.

Step 5: Select BACT Controls and Limits

Because none of the control options were deemed feasible, a CO limit, along with monitoring, recordkeeping, and reporting was set as BACT. Using the uncontrolled emissions of the CVS, the CO limit for the #1 and #2 PTA CVS has been determined to be 24.0 lb/hr and 20.0 lb/hr, respectively. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will be required to calculate and maintain hourly CO emissions. Hourly CO emissions shall be calculated on a 30-day rolling average. Reports of the calculated values shall be submitted semiannually, shall be maintained on site for a period of at least 5 years.

A source test to determine CO emission rates from each CVS is required within 180 days after startup, and every 3 years thereafter.

I. BACT for VOC and CO from #2 OX Unit HPVGTS Fired Heater

The #2 OX Unit HPVGTS Fired Heater preheats the waste gas feed stream to the #2 HPVGTS through indirect heat exchange. The VOC and CO emission are from combustion of natural gas fuel in the Fired Heater. The Fired Heater has a single burner that has a nominal rating of 15 MM BTU/hr, but actually operates less than 3 MM BTU/hr on average per year. The VOC and CO PTE from the Fired Heater is 0.4 and 5.4 tpy, respectively.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce VOC and CO emissions from this type of source:

- Good Combustion Practices – Good combustion practices for the Fired Heater is to maintain good air/fuel mixture in the combustion zone.
- Flue Gas Recirculation (FGR) – FGR is a method of reducing NOx emissions, by taking some of the re-circulated flue gas and mixing with combustion air. This mixture decreases the flame temperature and the availability of oxygen, thereby reducing the formation of thermal NOx.
- Natural Gas Fuel
- Tune-ups

Step 2: Technical Feasibility of Options

The use of FGR is not technically feasible since it is not compatible with the existing heater. The remaining control options are technically feasible since they all are successfully used on heaters.

Step 3: Ranking of Control Technologies by Control Effectiveness

The technically feasible control options are work practices and cannot be ranked.

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Economic Impact Analysis
The use of natural gas, tune-ups, and good combustion practices are currently being used, so there are no associated economic impacts. Use of these control options is economically feasible, as they save money by increasing energy efficiency.

Energy Impact Analysis
The feasible control options were evaluated for energy impacts, and it was determined that no unusual energy impacts exist. It was determined that the tune-ups and good combustion practices result in any energy benefits for BPCR, due to increase energy efficiency.

Environmental Impact Analysis
The feasible control options have some environmental benefit due to reduction in energy usage, which lowers emissions of combustion pollutants such as GHG, CO, and NOx.

Step 5: Select BACT Controls and Limits

BACT for the Fired Heater has been determined to be the sole use of natural gas, annual tune-ups, and good combustion practices. Using the AP-42 emission factors for natural gas combustion of 5.5 lb/MM SCF for VOC and 84 lb/MM SCF for CO, and a heat content of 1000 BTU/SCF; the VOC limit has been determined to be 0.0055 lb/MM BTU, and the CO limit has been determined to be 0.084 lb/MM BTU, each based on a 3-hour block average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR is required to monitor and record natural gas fuel usage on a monthly basis. Records of natural gas usage shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years.

BPCR is required to develop a tune-up plan and perform tune-ups on this source, once every 13 months. The tune-up plan will be developed in accordance with manufacturer's specifications or with good engineering practices. Records of tune-ups shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years. The tune-up plan shall only be included in the initial report. Subsequent submittals of the tune-up plan are required within 30 days of the change if the plan is modified or the Department requests additional information.

BPCR is required to implement good combustion practice(s) on this source, by maintaining proper air/fuel mixture in the combustion zone by holding excess oxygen between 3.5 and 12%. Percent (%) excess oxygen shall be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period (midnight to midnight), and shall be averaged together for a daily reading. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met:

- The daily average for a parameter is outside the approved monitoring range.
- The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.

J. BACT for VOC and CO from #1 OX Unit Emergency Generators

The #1 OX Unit will have installed two new emergency generators for this project (the BM-1201 Emergency Generator replacement and the new BM-1204 Emergency Generator). Both generators will be fired with diesel fuel, and will be subject to 40 CFR 60, Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines". The generators will be required to meet Tier 3 emission standards and will be limited to operating no more than 100 hours per year on a non-emergency basis. The 100 hours per year limit and the Tier 3 emission standards will make emissions of VOC (0.003 tpy) and CO (0.03 tpy) minimal. Therefore, a full BACT analysis was not performed on these two generators. The proposed BACT limit for each generator will be an operational restriction of no more than 100 hours per year of non-emergency use, compliance with Tier 3 emission standards, and the burning of only ultra low diesel as fuel. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR is required to record the actual operating hours of each generator on a monthly basis. Reports of the recorded hours of operation shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years.

BPCR is required to monitor and record diesel fuel usage on a monthly basis. Fuel oil supplier certification shall be obtained for each batch of oil received and stored on site. Records of diesel fuel usage and reports of the recorded sulfur content shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years.

K. Summary of BACT Limits

Table V.K-1: Summary of BACT Limits

Process/Equipment	Pollutant	BACT Limit	Control Method
#1 OX High Pressure Absorber	VOC	4.70 lb/hr	CTO
	CO	72.0 lb/hr	CTO
#1 OX Low Pressure Absorber	VOC	9.60 lb/hr	N/A
	CO	14.0 lb/hr	N/A
#1 OX Fugitives	VOC	HON LDAR	HON LDAR
#1 PTA Crystallizer Vents	VOC	20.0	N/A
	CO	24.0	N/A
#2 OX High Pressure Absorber	VOC	3.50	CTO
	CO	75.0	CTO
#2 OX Low Pressure Absorber	VOC	8.85	N/A
	CO	3.50	N/A
#2 OX Fugitives	VOC	HON LDAR	HON LDAR
#2 PTA Crystallizer Vents	VOC	20.0	N/A
	CO	20.0	N/A
#2 OX HPVGTS Fired Heater	VOC	0.0055 lbs/MM BTU	Good Combustion Practices, Natural Gas as sole fuel, Tune-ups
	CO	0.084 lbs/MM BTU	
#1 OX New Emergency Generators	VOC	100 hours per year non-emergency use, Tier 3 emission standards, and use of only ultra low sulfur (15 ppm) diesel fuel	N/A
	CO		

VI. Air Quality Impact Analysis

For a major facility, PSD regulations require an applicant to analyze the impact from the construction of a proposed new source(s) on the following areas:

1. Compliance with the National Ambient Air Quality Standards (NAAQS);
2. Compliance with the PSD Increments;
3. Significant impact on PSD Class I Areas, including Class I PSD increments;
4. Impairments to visibility, soil, and vegetation; and
5. Air Quality impact of general growth associated with the source.

All major sources proposing new construction or construction modifications in South Carolina (SC) are also required to demonstrate that their facility will remain in compliance with South Carolina Regulation 61-62.5 Standards 2 (AAQS), 7 (Class II PSD Increments) and 8 (Air Toxics).

General results of this compliance demonstration indicate that there will be no exceedances of NAAQS, South Carolina ambient air quality standards, or PSD increments. The proposed project is also not expected to cause any impairment in the vicinity of the facility to visibility, soils, and vegetation nor is any general commercial, residential, industrial, and other growth associated with the expansion expected to cause or contribute to a quantifiable adverse impact on local ambient air quality. In addition, there will also be no adverse effects on visibility, vegetation, or soils in any of the Class I areas within 300 km of the facility/source.

A. PSD Class II Modeling Analysis

The PSD review requires pollutants, which are determined to be "major," to be evaluated by an Air Quality Impact Analysis and Additional Impacts Analysis. The Air Quality Impact Analysis consists of: 1) a Preliminary Modeling Analysis to determine which pollutants from the proposed project, at the facility only**,** exceed their Class II Significant Impact Levels (SIL); and 2) for each pollutant that exceeds its SIL, a Full Impact Analysis that includes emissions from the facility, and those from nearby facilities that may cause an impact in the Significant Impact Area (SIA). The Additional Impacts Analysis evaluates the impacts on soils, vegetation, and visibility.

A.1. PSD Class II Preliminary Modeling Analysis

Potential emission rates or net emission rate increases, for each pollutant determined to be significant (Table IV-1) at the facility, were modeled to determine: a) impacts relative to the Significant Impact Level (SIL); b) the impact area within which a Full Impact Analysis must be performed (if applicable); and c) whether or not the facility may be exempted from the ambient monitoring data requirements. Each of these three preliminary Class II analyses are discussed below.

A.1.a. Significant Impact Level (SIL) Analysis

If a modeled impact is less than or equal to the SIL, then no further PSD analysis is required. Table VI-1 provides the results of the SIL modeling analysis for this project for the "major" pollutants as defined above (the impacts are the maximum modeled concentrations as noted in the table). Results are reported from the BAQ analysis. This analysis shows the SIL was not exceeded for CO for each respective averaging period. Therefore, no further PSD analysis is required for CO; however, CO must be included in the Standard 2 (facility-only) compliance analysis (Section E).

Table VI-1. Class II PSD Significant Impact Level

POLLUTANT	AVERAGING TIME	MODEL USED	MAXIMUM IMPACT ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Exceeds SIL? (Yes/No)	SIGNIFICANT IMPACT AREA (km)
CO	1 HOUR	AERMOD	243	2000	No	N/A
	8 HOUR	AERMOD	120	500	No	N/A

Maximum concentrations are used for the Significant Impact Level analysis (i.e. Highest-First-High).

It should be noted that while the DHT Overhead Scrubber (BT-702) is an offset emission source with a negative emission rate, this source would have operated at the previously estimated rate only sporadically. Consequently, the results shown in Table VI-1 only include the stacks with positive emissions rates. These predicted values are below the PSD significant impact thresholds of 2,000 µg/m3 (1-hour) and 500 µg/m3 (8-hours). Therefore, no further modeling analysis is required for CO.

Analysis for Volatile Organic Compound Impact

For the VOC emissions increases, this project was evaluated using a project related net increase in VOC emissions of 164.4 TPY. The estimated increase in emissions of NO_X is below the PSD significant emission increase threshold.

The area measured values of ozone in the Charleston area for the last 3 years are listed below.

- Bushy Park Monitor # 45015002
    - 8-hour average 4th high – 0.061 ppm, 0.065 ppm, 0.066 ppm (2012, 2011, 2010)
- Cape Romain # 450190046
    - 8-hour average 4th high – 0.064 ppm, 0.066 ppm, 0.068 ppm (2012, 2011, 2010)

The National Ambient Air Quality Standard (NAAQS) for ozone is 0.075 ppm. The monitored values above show the area to be well in attainment of the 8-hour ozone NAAQS.

The VOC impact was based on the project having an increase in VOC emissions of 164.4 TPY and less than 40 TPY of NO_X emissions. The Southeastern United States, including South Carolina, is NO_X limited with regards to ozone formation. This means that there is an excess of VOC in the atmosphere with regards to ozone formation and increases in VOC do not lead to increases in ozone production. The excess VOC is in part due to natural sources in the environment. Due to the excess VOC, only increases in NO_X in this region are a concern with regards to ozone formation. This project does not result in a significant increase in NO_X emissions so it would be expected that the project as a whole would have minimal impact on area ozone concentrations. Ambient impacts from NO_X are addressed in NO_X modeling.

To better assess the relative nature of the project increase in VOC emissions, average actual VOC emissions for the Charleston County and three other surrounding Counties are presented below.

COUNTY 3-YEAR AVERAGE ACTUAL VOC EMISSIONS (TPY)

- Charleston 1,430
- Berkeley 1,625
- Dorchester 470
- Colleton 857
- Total for Area 4,382

The project VOC emissions impact was based on an estimated VOC emissions increase of 164.4 TPY from this project. This value represents 3.8 percent of the actual area-wide point source emissions of VOCs. Note that this total does not include mobile sources or emissions from minor sources in the area.

Because project emission level increases for VOCs for this project are relatively small and the project does not have a significant increase in NO_X emissions (recall the area is NO_X limited with respect to the formation of ozone), it is concluded this project would not cause or contribute to a violation of the NAAQS for ozone.

A.1.b. Significant Impact Area (SIA) Analysis

The SIA is a circular area with a radius extending from the source to the lesser of: 1) the most distant point where the Preliminary Modeling Analysis predicts a significant ambient impact will occur (greater than the SIL), or 2) a modeling receptor distance of 50 km. The SIA will contain the receptor field and additional sources to be used in the Full Impact Analysis (sources in the Screening Area (SA) will also be included, as appropriate).

Since no pollutant concentrations exceeded their respective SILs, this project is not subject to the SIA analysis.

A.1.c. Significant Monitoring Concentration Analysis

Modeling significance results (impacts) for CO are shown below along with significant monitoring concentrations (SMC) for these pollutants. The impacts are the maximum modeled concentrations as noted in the table. The significant monitoring concentrations are from SC Regulation 61-62.5, Standard 7.

Table VI-2. Significant Monitoring Concentrations

Pollutant	Averaging Period	Max. Impact (µg/m^3)$^{(1)}$	Significant Monitoring Concentration (µg/m^3)	Exceeds (Y or N)
CO	8-Hour	120	575	NO
1) Highest-first-high concentration				

The maximum impacts for CO are below the significant monitoring concentration (SMC) levels; therefore, no pre-construction monitoring is required for this pollutant.

Since this project is significant for VOCs, ozone monitoring data also needs to be reviewed. Section 2.4 of U.S. EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007) permits the use of existing representative air quality data in place of preconstruction monitoring data, provided the monitor location, how current the data is, and the quality of data are acceptable.

The nearest regional monitors for the BP Amoco – Cooper River Plant for ozone are the Cape Romain and Bushy Park stations as previously discussed. The Cape Romain station is located approximately 30 km from the BP Amoco facility and the Bushy Park station is located approximately 7 km from the BP Amoco facility. Both stations are representative of the ambient ozone background concentrations at the BP Amoco facility and, as previously indicated, data from both stations indicate this area is in attainment for the ozone NAAQS.

These monitors are operated by the SC DHEC in support of National Ambient Air Quality Standards attainment activities and meet the quality assurance requirements for this work. These activities require the data to be quality assured, and the level of quality assurance for these monitors meets the requirements for PSD modeling.

Therefore, it has been determined that the data DHEC has obtained for background concentrations are representative of the ambient pollutant concentrations in the area of the proposed facility. In accordance with Chapter C, Section III of the New Source Review Manual (Draft document, dated October 1990), the Bureau approves the use of ambient data collected at DHEC monitoring stations for pre-construction monitoring requirements.

A.2. PSD Class II Full Impact Modeling Analysis

A Full Impact Analysis is required for any pollutant for which the proposed source's estimated (modeled) ambient pollutant concentrations exceed the SIL (determined in Table VI-1).

Since no pollutant concentrations exceeded the respective SILs, this project is not subject to Full Impact Modeling.

B. Additional Impacts Analysis

PSD review requires an analysis of any potential impairment to visibility, soils, and vegetation that may occur as a result of the proposed or modified facility/sources. The review also requires an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the expansion.

B.1. Growth

The SC PSD rules require the applicant to provide information relating to the nature and extent of air quality impacts from all commercial, residential, industrial and other growth in the area the facility, or modification, would affect. For the purposes of this report, the area the facility would affect is defined as the area of significant impact. This project does not require development of a significant impact area, and the proposed modification at the facility is not anticipated to result in any significant increase in full-time employment (or an associated increase in traffic flow) at the facility. Nor is there any construction activity related to the project that would result in a temporary increase in local traffic. Therefore, the construction and modification of the facility and any workforce-associated residential and commercial growth is not expected to cause or contribute to a quantifiable adverse impact on local ambient air quality.

B.2. Soils and Vegetation

Maximum predicted offsite impacts were compared to EPA screening levels or secondary NAAQS. Modeling of all the proposed emissions for the soils and vegetation analysis indicates that there will be no adverse impacts expected on soils or vegetation caused by the proposed facility emissions.

Table VI-3. Soils And Vegetation Analysis

Pollutant	Averaging Time	Model Used	MAX. Impact ($\mu g/m^3$)[1]	Back-ground ($\mu g/m^3$)	Facility / Regional Impact ($\mu g/m^3$)[2]	EPA Screening Concentration ($\mu g/m^3$)	AAQS Standard ($\mu g/m^3$)	Exceeds?
CO	1 Week [3]	AERMOD	120[4]	916	1036	1,800,000	N/A	No

1) All values, unless noted otherwise, are the highest-first-high modeled concentration and include full impact sources.

2) Results include background values when available.

Table VI-3. Soils And Vegetation Analysis

Pollutant	Averaging Time	Model Used	MAX. Impact ($\mu g/m^3$)(1)	Back-ground ($\mu g/m^3$)	Facility / Regional Impact ($\mu g/m^3$)(2)	EPA Screening Concentration ($\mu g/m^3$)	AAQS Standard ($\mu g/m^3$)	Exceeds?
3) Non-Standard Averaging period was conservatively estimated as follows: • CO 1-Week = 8-hour concentration compared to weekly standard. Background is also 8-hr value.								
4) Concentration includes only the facility impact since the concentration either did not exceed the Significant Impact Level (SIL) or no SIL was available.								

B.3. Visibility

This visibility impairment analysis is distinct from the Class I visibility impact analysis. VISCREEN can be used following the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015, 1988). The procedure consists of a screening process done through several levels. A nearby sensitive receptor, such as a state park or local airport, is analyzed to determine if an impact is expected.

This project triggers PSD air quality evaluation requirements for CO and VOCs only. Neither of these pollutants is typically understood to affect visibility so no visibility impairment assessment is needed or was undertaken (i.e. the VISCREEN model used for visibility analysis does not have inputs for CO or VOC).

C. PSD Class I Impact Analysis

A facility within 300 km of a Class I area must address the impact on the Class I area. For the visibility and deposition analyses, the recommendations in the following should be consulted: 1) *Interagency Workgroup on Air Quality Modeling Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts (IWAQM)* (EPA-454/R-98-019, December 1998); 2) *Federal Land Managers' Air Quality Related Values Workgroup Phase I Report (FLAG 2010)* (U.S. Forest Service- Air Quality Program, the National Park Service – Air Resources Division, and the U.S. Fish & Wildlife Service – Air Quality Branch, December 2000); 3) *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology* (EPA, June 15, 2005); and 4) EPA's *Guidelines on Air Quality Models (Guideline)*.

C.1. Class I Increment Consumption Impact Analysis

This analysis is not required since there are no increments for CO or VOCs.

C.2. Class I Visibility Analysis

The visibility analysis evaluates the potential change in light extinction relative to the natural background as a result of the proposed project. Visibility is described through two methods, Plume Impairment (less than 50 km) and Regional Haze (greater than 50 km). Regional haze occurs at distances where the plume has become evenly dispersed into the atmosphere such that there is no definable plume. The EPA guidance (IWAQM, 1998 Revised) and the FLM guidance (FLAG, 2010) recommend the use of non-steady state dispersion modeling for both screening and refined dispersion modeling.

Typically plume impairment would not be evaluated for a project of this type as it triggers a PSD air quality evaluation requirement for CO only, and this pollutant does not affect visibility. However, the U.S. Fish and Wildlife Service requested that an air quality analysis be performed for the Cape Romain National Wildlife Refuge, the nearest Class I area to the facility. Since the distance to the Cape Romain National Wildlife Refuge (NWR) was less than 50 km, regional haze was not evaluated.

A Level 1 default screening analysis was performed in VISCREEN following the guidelines published in the Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015, 1988; Revised 1992) (hereafter referred to as the workbook). The facility used the workbook approach default settings of F stability and a 1 m/s wind speed (a worst-case meteorological condition).

Since the background visual ranges included in the Workbook have since been updated in the FLAG 2010 guidance, the updated visual range was included. The monthly values included in Table 10 of FLAG 2010 for Cape Romain were averaged to determine a single annual background visual range of 174.92 km which was input into the model.

The Cape Romain Wildlife Refuge is located 24 km east of the facility. The impacts were evaluated against the Level I default VISCREEN criteria and passed. Calculations were performed for two assumed plume-viewing backgrounds: the horizon sky and a dark terrain object. The table below shows the screening values from the results obtained using the workbook method.

Table V1-4. PSD Class I Visibility Impairment Analysis

Background	Theta	Azimuth	Distance (km)	Alpha	ΔE Critical	ΔE Plume	Contrast Critical	Contrast Plume
Sky	10	133	30.0	36	2.0	0.220	0.05	0.003
Sky	140	133	30.0	36	2.0	0.154	0.05	-0.002
Terrain	10	84	24.0	84	2.0	0.523	0.05	0.003
Terrain	140	84	24.0	84	2.0	0.038	0.05	0.000

Table VI-5. PSD Class I Visibility Impairment Analysis Inputs

Parameter	Value	Units
Particulate Matter	6.6	tpy

Table VI-5. PSD Class I Visibility Impairment Analysis Inputs

Parameter	Value	Units
Nitrogen Dioxides	27.8	tpy
Primary Sulfur	0.2	tpy
Background Ozone	0.04	ppm
Plume-source-observer angle	11.25	degrees
Background visual range	174.92	km
Wind Speed	1	m/s
Stability Class (Index)	F (6)	class

C.3. Class I Deposition Analysis

This project triggers PSD air quality evaluation requirements for CO and VOCs only. These pollutants are not pollutants of concern related to soil or surface water deposition, so no deposition assessment is needed.

D. South Carolina Facility-wide Compliance Demonstration

All major sources proposing new construction or construction modifications in South Carolina are required to demonstrate compliance with South Carolina Regulation No. 62.5 Standards 2 (NAAQS), 7 (Class II PSD Increment), and 8 (Air Toxics) [Standard 7 (PSD) Part k - "Source Impact Analysis" and Part p - "Sources Impacting Federal Class I Areas - Additional Requirements" were addressed in Sections B and D above, as appropriate].

Facility-wide emissions from the facility only were considered to demonstrate compliance with Standard 2, 7 and 8, the results of which are shown in the tables below.

Table VI-6. Standard No. 2 – Ambient Air Quality Standards Modeling Analysis

Pollutant	Averaging Time	Basis	Maximum Concentration ($\mu g/m^3$)(1)	Background Concentration ($\mu g/m^3$)	Total ($\mu g/m^3$)	Standard ($\mu g/m^3$)	% of Standard
PM_{10}	24 Hour	ISCST3	29.3	38	67	150	45
$PM_{2.5}$	24 Hour	--	(2)	--	--	35	--
	Annual	--	(2)	--	--	12	--
SO_2(3)	3 Hour	ISCST3	138.1	130.9	269	1300	21
NO_2	Annual	ISCST3	20.0	19.0	39	100	39
CO	1 Hour	AERMOD	243	1450.3	1693.3	40,000	4
	8 Hour	AERMOD	120	916.0	1036.0	10,000	10

1) The highest-first-high modeled concentration was used for annual averaging periods and the highest-second-high was used for all other averaging periods, except where noted otherwise.

2) The PM10 surrogate was used to demonstrate compliance with the PM2.5 standards.

Table VI-7. Background Monitoring Data (μg/m3)

Pollutant	Site Name	County	Year	1-Hr	3-Hr	8-Hr	24-Hr	3-Mo	Annual
PM_{10}	Cape Romain	Charleston	2005				38		
SO_2	Cape Romain	Charleston	2005	n/a	130.9				
NO_2	Jenkens Ave Fire Sta	Charleston	2005	n/a					19.0
CO	Parklane	Richland	11-13	1450.3		916.0			

PM_{10} 24-hr is the fourth-high over three year period.
The concentration listed for all other pollutants and averaging periods is the 3 year design value.

Table VI-8. Standard No. 7 - Class II PSD Modeling Analysis

Pollutant	Averaging Time	Basis	Maximum Concentration $(\mu g/m^3)^{(1)}$	Standard $(\mu g/m^3)$	% Of Standard
PM_{10}	24 Hour	ISCST3	6	30	20
	Annual	ISCST3	1	17	6
SO_2	3 Hour	ISCST3	70	512	14
	24 Hour	ISCST3	25	91	27
	Annual	ISCST3	0	20	0
NO_2	Annual	ISCST3	4	25	16

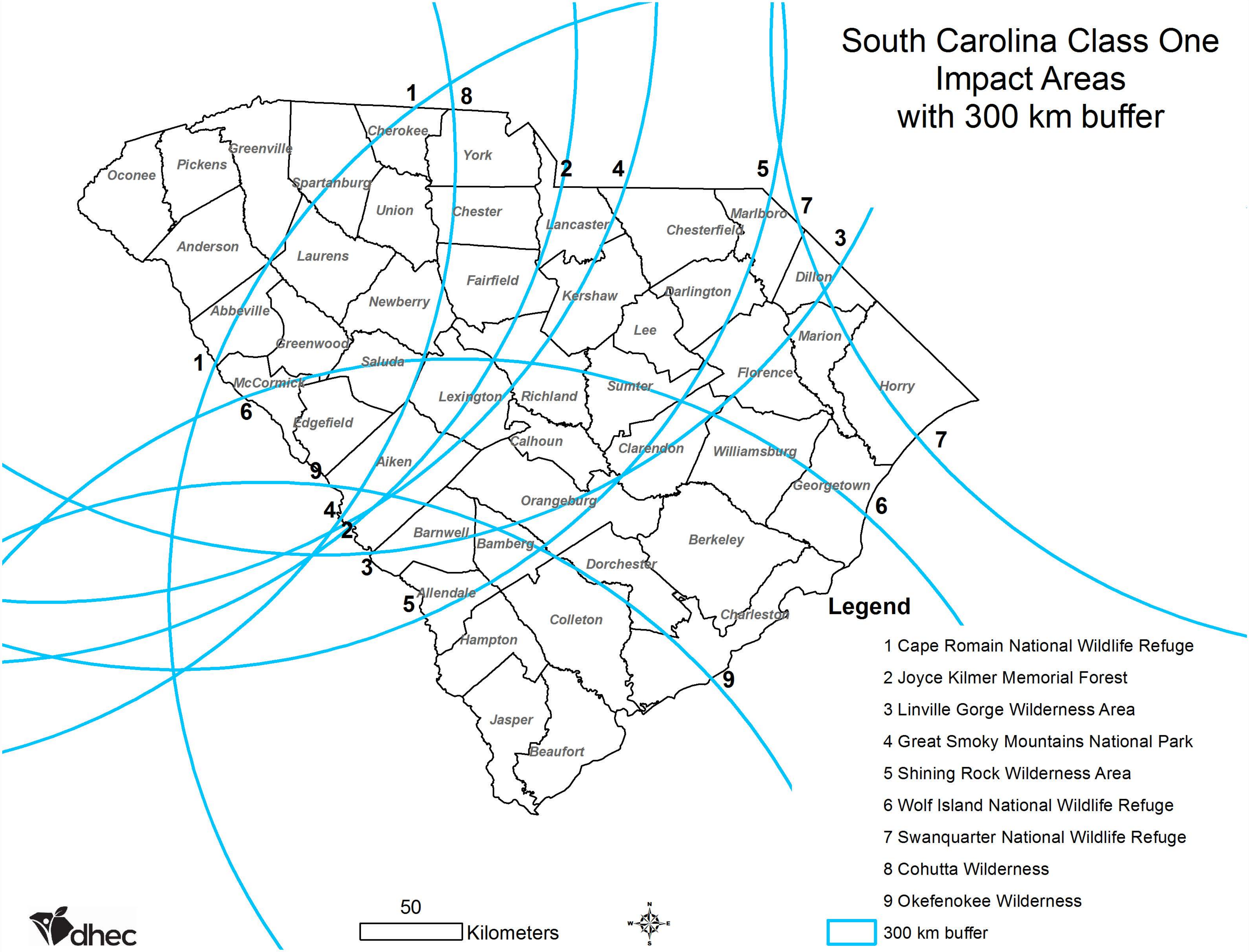
1) The highest-first-high modeled concentration was used for annual averaging periods and the highest-second-high was used for all other averaging periods.

All sources that emit air toxics at the facility have been determined to be controlled by the HON MACT. Therefore, all toxics emissions are exempt from Standard 8.

Appendix A

Class I Area Map

South Carolina Class One Impact Areas with 300 km buffer



Legend

1 Cape Romain National Wildlife Refuge
2 Joyce Kilmer Memorial Forest
3 Linville Gorge Wilderness Area
4 Great Smoky Mountains National Park
5 Shining Rock Wilderness Area
6 Wolf Island National Wildlife Refuge
7 Swanquarter National Wildlife Refuge
8 Cohutta Wilderness
9 Okefenokee Wilderness
□ 300 km buffer

dhec

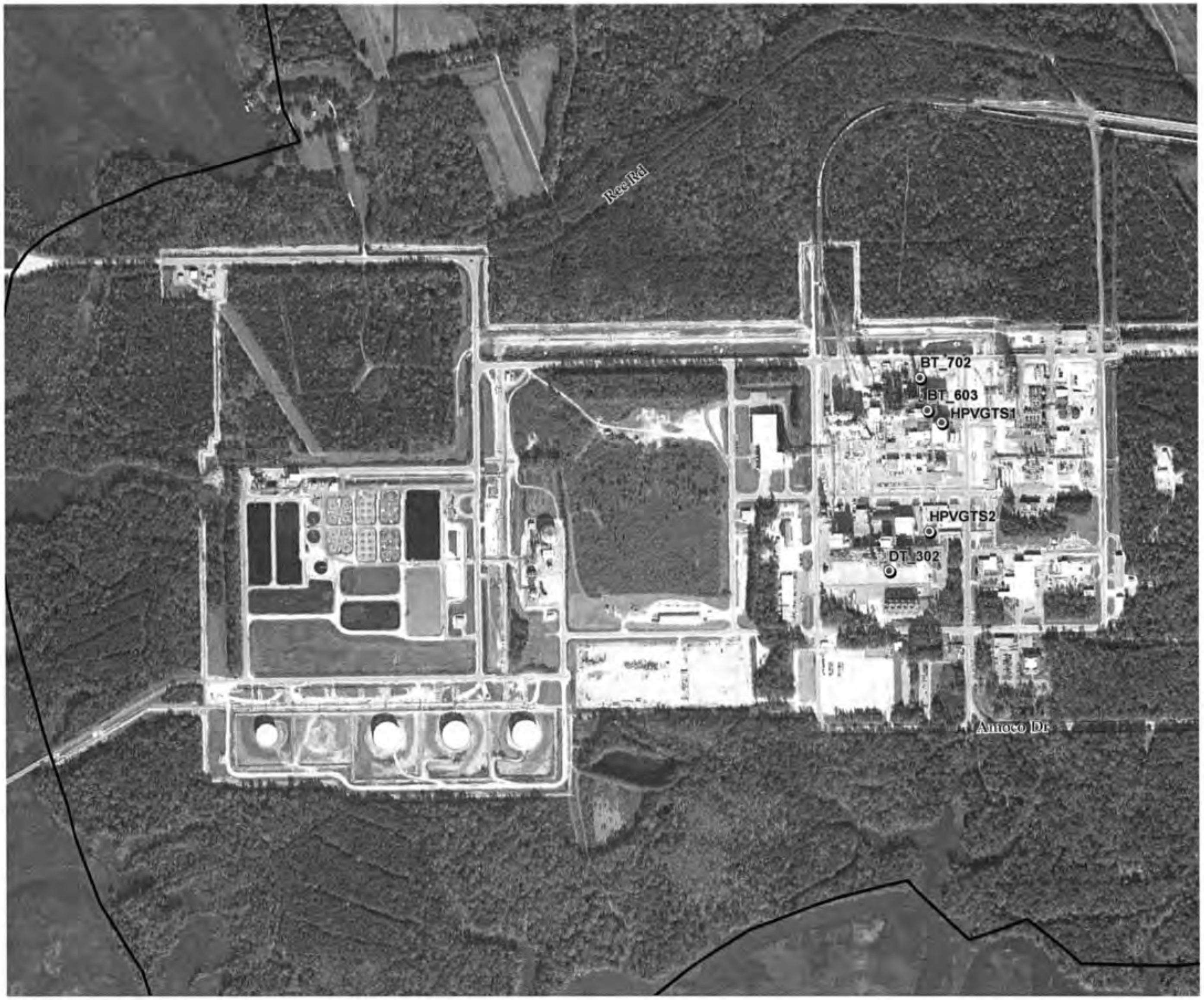
Appendix B

Site Location Map

LEGEND

APPROXIMATE FACILITY BOUNDARY

◉ STACK LOCATION



NOTES

1. BASE MAP IMAGERY FROM ESRI WEB SERVICE BASEMAP LAYER, "WORLD IMAGERY".

0 1,000 2,000 FEET

1 INCH = 1,000 FEET

1:12,000

N

TRC - GIS

TRC

50 International Drive
Suite 150
Patewood Plaza Three
Greenville, SC 29615

BP COOPER RIVER
SOUTH CAROLINA

FIGURE 5-3
PROJECT EMISSION SOURCES

DRAWN BY:	PAPEZ J
APPROVED BY:	FOX D
PROJ. NO.:	187464
FILE NO.:	187464-002.mxd
DATE:	JANUARY 2013

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Appendix C

PSD Permit Application

ED
Jam R.

Prevention of Significant Deterioration (PSD) Air Permit Application for Process Modification BT-603

BP Amoco Chemical Company – Cooper River Plant

Wando, South Carolina

December 2017, March 2018

Public Version

RECEIVED
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BUREAU OF AIR QUALITY

Robert vandenMeiracker
Office Practice Leader, Planning, Permitting, and Licensing

Jack Bailey
W. Mark Bailey
Project Manager

TRC Environmental Corporation | BP Amoco Chemical Company - Cooper River Plant
PSD Air Permit Application
Process Modification BT-603
Public Version
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Section 1
Introduction

1.1 Background

BP Amoco Chemical Company – Cooper River Plant (BP CR) currently owns and operates a chemical manufacturing facility in Wando, South Carolina that produces purified terephthalic acid (PTA). The BP CR plant, wholly owned and operated by BP, is located on a 6,000-acre site in Berkeley County, South Carolina on the east bank of the Cooper River, about 16 miles upstream of the Atlantic Ocean. The facility location is as follows:

BP Amoco Chemical Company – Cooper River Plant
1306 Amoco Drive
Wando, South Carolina 29492

The BP CR Plant belongs to the Standard Industrial Classification (SIC) Code group 2869. The product PTA is a white, inert powder used to make polyester fibers, bottles, and films. The major raw materials in the production of PTA are paraxylene (PX), acetic acid (HAC), and hydrogen. Plant operation consists of the following five major processes:

1. Oxidation (OX) units for production of crude terephthalic acid (TA)
2. PTA units for purification of crude TA into PTA
3. Product loading/shipping
4. Utilities
5. Wastewater treatment.

Crude TA is produced in the OX units by the air oxidation of PX in an HAC solution and the presence of a catalyst at high temperature and pressure. The crude TA is crystallized and separated from the mother liquor and dried. Catalyst and mother liquor recycle are routinely operated at very high rates as a result of waste minimization and economic initiatives at the plant.

Crude TA is purified in the PTA units in an aqueous solution by hydrogenation in the presence of a catalyst. The purified product is crystallized, separated, dried, and shipped. Reject product from the silo baghouse, or loading shaker screens is routinely rerun, as an alternative to sending it to the wastewater treatment unit. TA solids in the wastewater treatment plant (WWTP) influent are settled out, recovered, and can be sold as a product, BACA (byproduct aromatic carboxylic acid).

1.2 Purpose and Scope

BP CR has retained TRC Environmental Corporation (TRC) to assist in the preparation of an air construction permit application package for proposed revisions at the BP CR facility. BP CR is currently a Title V source and a major source for both hazardous air pollutants (HAPs) and Prevention of Significant Deterioration (PSD).

BP CR is proposing to change the method of operation for equipment in the #1 OX unit that is routed to the low pressure absorber, BT-603. The change will allow BP to produce PTA at a lower unit operating cost. The net result of the change from an emissions perspective will be an increase in allowable carbon monoxide (CO) emissions from 4.1 pounds per hour (lb/hr) to 14 lb/hr. BP anticipates making the change in method of operation in early 2018. As part of this project, BP also proposes to voluntarily reduce the allowable CO limit for the high pressure vent gas treatment system (HPVGTS) from 87.9 lb/hr to 72 lb/hr. The change in allowable emissions for this project and the voluntary decrease will be a reduction of 6 lb/hr.

Note that the CO emission limits from BT-603 and the HPVGTS are PSD limits that were set based on construction permit 0420-0029-CU and the associated permit application; also known as the "Dragonslayer" project.

This project will not result in an increase in hourly or annual production. The project will not debottleneck any other processes at the facility and will not result in additional demand for utilities such as steam or electricity.

A PSD applicability analysis has been performed for the project recognizing that the area is in attainment for all regulated pollutants. The project PSD applicability analysis demonstrates that a significant net emissions increase will occur for CO; therefore the project is subject to review under the PSD permitting program for CO. Other pollutants were evaluated and determined to be less than PSD significance thresholds. The Federal Land Manager (FLM) responsible for the Romain Wilderness area, which is a federal Class 1 Wilderness about 22 kilometers from the site, was re-contacted to determine the FLM's interest in the PSD application. In their initial review of the project, the FLM did not request that a Class I Air Quality Related Value (AQRV) analysis be included in the PSD permit application. BP CR is required to file a permit application with South Carolina Department of Health and Environmental Control (SC DHEC) to obtain approval to commence construction on the project via the issuance of an air construction permit. To satisfy this requirement, this permit application has been prepared in accordance with SC DHEC guidelines for air construction permitting including the required PSD permitting elements for CO. This application contains the following items:

- Section 1 Introduction

Section 2	Project Description
Section 3	Regulatory Assessment
Section 4	Best Available Control Technology Analysis for CO
Section 5	Air Quality Analysis for CO
Section 6	Additional Impacts Analysis
Appendix A	SC DHEC Permit Application Forms
Appendix B	Emissions Data and Calculations
Appendix C	RBLC Search Results
Appendix D	BACT Analysis Cost Information
Appendix E	Federal Land Manager Reply
Appendix F	Air Modeling Information
Appendix G	USEPA Control Technology Fact Sheet – Incinerators

1.3 Facility Location and Contact

All correspondence regarding this permit application should be sent to the following:

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Environmental Engineer
BP Cooper River Plant
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Marianne.Andrews2@bp.com
843.800.3478

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Greenville, SC 29615
rvandenmeiracker@trcsolutions.com
864.787.5261

Section 2
Project Description

2.1 Existing Process Description

BP CR has two PTA production units, each consisting of OX and PTA sections. The OX areas produce TA (terephthalic acid). In the PTA sections, the TA is purified to produce PTA, sent to shipping and loading where it is stored in one of several silos and loaded into shipping containers. A simplified flow of the overall process is shown in Figure 2-1.1. Since this project only affects #1 OX, the process description below is, in general, limited to the #1 unit.

In the OX unit, a BP proprietary process is used for the catalytic liquid phase air oxidation of PX to produce TA. HAC and catalyst solution are mixed in a feed mix drum while PX is directly injected into the #1 OX reactor. The raw materials and air from the process air compressor are continuously fed to the reactors. Exothermic heat of reaction is removed by condensing the boiling reaction solvent. A portion of this condensate is withdrawn to control the water concentration in the reactor and the remainder is refluxed back to the reactor.

Reactor effluent is depressurized and cooled to filtering conditions in a series of crystallizers to form the solid TA crystals. Air is fed to the first crystallizer for additional reaction. The crystallizer temperatures are controlled by allowing a portion of the reaction solvent to flash off. The crystallizer vent streams are sent to the dehydration tower (DHT) and the High Pressure Absorber (HPA) for recovery of valuable materials. The DHT also removes water formed in the reaction. The crystallizer precipitate TA is recovered by filtration and finally dried. The dried TA solids are conveyed to the OX intermediate storage silos (TA) silos and stored for additional processing in the PTA unit.

The off-gas from the OX reactor is routed to the HPVGTS. The #1 DHT overhead gases are routed to the DHT scrubber, BT-702, which is routed to BT-603. The HPVGTS reactor contains catalyst bricks that are routinely replaced based on their activity and mechanical condition. Further processing in the OX unit is required to recover and purify HAC from the reactor outlet, crystallizer solvent withdrawal streams, and also from the un-recycled mother liquor stream. OX byproducts are separated from the HAC in a two-stage evaporation process and then purged.

The PTA unit is also a continuous operation. Crude TA is fed from the OX intermediate storage silos to the feed slurry drum to produce the slurry of TA crystals and water. The slurry is heated to dissolve the TA and then the slurry enters the hydrogenation reactor where it reacts to convert the impurities into a form that can be separated from the product. The PTA reactor catalyst is routinely replaced based on its activity and mechanical condition. After reaction, the solution goes through a cycle of lowering the pressure and cooling to crystallize the PTA. A portion of the aromatic acids in the mother liquor are recovered by cooling and filtering the mother liquor; the aromatic acids are recycled back to the OX reaction unit.

The crystallized PTA is recovered from the mother liquor by separation in the filtration section of the unit. The final product is dried and transferred to the PTA day silos and then to the PTA product storage silos.

The #1 and #2 Cooling Towers supply non-contact cooling water to the respective #1 OX/PTA and #2 OX/PTA units. The Cooling Tower particulate matter (PM) emissions are Title V insignificant activities.

2.2 Project Description

The proposed BT-603 project will result in a change in the method of operation of #1 OX. Currently the facility is withdrawing solvent/water mixture from overhead condensers 2 & 3 to the DHT, BT-702, and BT-603 which vents to the atmosphere. BP proposes to withdraw from each of the three condensers. The result is better catalyst recovery and more stable operation, which will provide a significant operational savings on an annual basis. The project will result in an increase of CO emissions from the #1 OX low pressure absorber (LPA) because the first condenser's solvent/water mixture contains higher concentrations of CO. CO will be released through the separation process in the dehydration tower, which ultimately vents to atmosphere through the LPA. The project does not affect emissions of other pollutants including those other pollutants regulated by PSD, thus the emissions calculations are limited to CO emissions. A simplified process diagram for the #1 OX unit is shown in Figure 2-1.2. The #2 OX unit will not be impacted by the proposed project.

BP CR proposes to complete the change after receipt of the permit which is anticipated in early 2018.

2.3 Unit Emissions

Emissions calculations for the #1 OX unit are included in Appendix B of this application to determine PSD applicability. A summary of the PSD analysis in Appendix B is shown in Table 2-1. As this table shows, the change in CO emissions is an increase that is greater than the PSD significance thresholds for CO. The unit's potential-to-emit (PTE) emissions are based on 8,760 hours per year of operation at design capacities and modified emission limits for BT-603 and the HPVGTS. A summary of CO emissions from contemporaneous projects described in the Dragonslayer application is also shown below.

The emissions calculations in Appendix B provide the various emissions estimates requested in the applications forms. The PSD emission calculations for the modified unit (#1 OX) are based on Post Project PTE – Baseline Average Emissions (BAE). The PSD emission calculations do not include any calculations for unmodified units such as the Utilities, Tank Farm and Shipping, because these units are not affected and are not debottlenecked by this project. As noted previously, the project will not result in an increase in hourly or annual production. The pre- and post-emissions are calculated for the controlled scenario. The emissions calculations are included in Appendix B in the following tables as shown in Table 2-2.

Table 2-1
Prevention of Significant Deterioration Analysis Summary

Step 1

POLLUTANTS	TOTAL PTE	TOTAL TWO-YEAR BASELINE AVERAGE	EMISSION INCREASE	PSD SIGNIFICANCE THRESHOLD	ABOVE PSD?
CO	376.7	275.1	101.6	100	**Yes**

Contemporaneous Emissions

PROJECT	YEAR	CO (tpy)
502b10 - CR #1 OX BR-301A Alternate Water Withdrawal	2008	0.0
PTA FIP Project (Permit CS)	2008	0.01
502b10 - #1 OX/PTA Op Flex	2011	0
PTA Filter Project	2012	26.9
Total	---	**26.9**

Table 2-1
Prevention of Significant Deterioration Analysis Summary

Step 2 – Facility Netting

POLLUTANTS	CO
Step 1 Delta	101.6
Total Contemporaneous	26.9
Net Emissions	128.5
PSD Significance	100
Above PSD	**Yes**

Table 2-2
Appendix B Tables

TABLE NO	CALCULATION
1	PSD Applicability Summary
2	#1 Ox Unit Emissions
3	Fugitive Emissions

2.4 Prevention of Significant Deterioration Emission Limits

As a result of this application and the Best Available Control Technology (BACT) analysis included for CO emissions (see Section 4 of this application), the following existing BACT limits shown in Table 2-3 are requested to be modified by the applicable BACT/PSD limits shown in the table.

Table 2-3
Emission Limit Revisions

EMISSION POINT	POLLUTANT	CURRENT BACT LIMIT (lb/hr)	REQUESTED BACT LIMIT (lbs/hr)	BACT LIMITS (Averaging Time)
#1 OX LPA	CO	4.1	14	30 days
#1 HPVGTS	CO	87.9	72.0	30 days

2.5 BACT Monitoring

As part of this project, BP does not propose any change to the monitoring requirements from the previous PSD application (Dragonslayer) for #1 OX LPA and HPVGTS. Table 2-4 is a summary of the existing monitoring parameters.

Table 2-4
BACT Monitoring Parameters

UNIT	EMISSION POINT	POLLUTANT	PARAMETER 1 MONITORED	PARAMETER 2 MONITORED
#1 OX	LPA	CO	Performance Test every 3 years	N/A
	HPVGTS	CO	Reactor Inlet Temperature	Reactor Outlet Temperature

Table 2-5 indicates the monitoring and reporting frequency for the BACT monitoring parameters. For parameters that have a monitoring frequency specified as "continuously with daily average," at least one data point shall be obtained each 15-minute period and all data points collected within a 24-hour period (during those times that the process or emissions generating equipment was being operated) shall be averaged together for a daily reading for comparison to an established monitoring range. All records of the parameters will maintained for at least 5 years after being recorded.

Table 2-5
BACT Monitoring Frequency and Reporting

UNIT	EMISSION POINT	PARAMETER	FREQUENCY	REPORTING
#1 OX	HPVGTS	Reactor Inlet Temperature	Continuously with daily average	Semiannual
		Reactor Outlet Temperature	Continuously with daily average	Semiannual

Figure 2-1
BP Cooper River Overall Process Flow Diagram

Entire Page is Confidential

Figure 2-2
#1 OX Unit Process Flow Diagram

Entire Page is Confidential

Section 3
Applicable Regulations

A regulatory assessment was completed for the proposed change in method of operation for the #1 OX Unit at the BP CR Plant. A review of both South Carolina and Federal regulations was conducted to determine the applicable air quality requirements for the proposed project. Each potentially applicable regulation is summarized in Table 3-1 and is described in the following subsections and, where applicable, the emissions limits are outlined as well as the required record keeping and monitoring requirements.

Table 3-1
Summary of Potentially Applicable Regulations

REGULATORY ASSESSMENT SUMMARY		
POTENTIALLY APPLICABLE REGULATIONS		APPLICABLE TO PROJECT
State (SC DHEC) Regulations		
SC DHEC Reg 61-62.5 Section II	Permit Requirements	Y
SC DHEC Reg 61-62.5 Std. No. 1	Emissions from Fuel Burning Operations	N
SC DHEC Reg 61-62.5 Std. No. 1	Ambient Air Quality Standards	Y
SC DHEC Reg 61-62.5 Std. No. 3	Waste Combustion and Reduction	N
SC DHEC Reg 61-62.5 Std. No. 4	Emissions from Process Industries	Y, no change
SC DHEC Reg 61-62.5 Std. No. 5.2	Control of NO_x	N
SC DHEC Reg 61-62.5 Std. No. 7	PSD	Y
SC DHEC Reg 61-62.5 Std. No. 8	TAPs	N
SC DHEC Reg 61-62.7	GEP Stack Height	Y
SC DHEC Reg 61-62.60	New Source Performance Standards (NSPS)	Y, no change
SC DHEC Reg 61-62.61	National Emission Standards for Hazardous Air Pollutant (NESHAP)	Y, no change
SC DHEC Reg 61-62.63	NESHAPs for Source Categories	Y, no change
Federal Regulations		
40 CFR Part 60, Subpart A	General Provisions	Y, no change
40 CFR Part 60, Subpart Da	NSPS for Electric Utility Steam Generating Units	N
40 CFR Part 60, Subpart Db	NSPS for Industrial-Commercial-Institutional Steam Generating Units	N
40 CFR Part 60, Subpart Kb	NSPS for Volatile Organic Liquid Storage Tanks	N

Table 3-1
Summary of Potentially Applicable Regulations

REGULATORY ASSESSMENT SUMMARY		
POTENTIALLY APPLICABLE REGULATIONS		APPLICABLE TO PROJECT
40 CFR Part 60, Subpart VV	NSPS for Equipment Leaks of VOC in the SOCMI Before November 7, 2006	Y, no change
40 CFR Part 60, Subpart VVa	NSPS for Equipment Leaks of VOC in the SOCMI After November 7, 2006	Y, no change
40 CFR Part 60, Subpart III	NSPS for VOC Emissions from the SOCMI Air Oxidation Unit Processes	Y, no change
40 CFR Part 60, Subpart NNN	NSPS for VOC Emissions from SOCMI Distillation Operations	Y, no change
40 CFR Part 60, Subpart RRR	NSPS for VOC Emissions from SOCMI Reactor Operations	N
40 CFR Part 60, Subpart YYY (proposed)	VOC Emissions from SOCMI Wastewater	Will review when rule finalized
40 CFR Part 60, Subpart IIII	NSPS for Stationary Compression Ignition Internal Combustion Engines	N
40 CFR Part 61, Subpart M	National Emission Standard for Asbestos	Y, no change
40 CFR Part 61, Subpart V	National Emission Standard for Equipment Leaks (Fugitive Emission Sources)	N
40 CFR Part 61, Subpart FF	National Emission Standard for Benzene Waste Operations	Y, no change
40 CFR Part 63, Subpart A	NESHAPs for Source Categories; General Provisions	Y, no change
40 CFR Part 63, Subpart F	NESHAPs for Source Categories; Hazardous Organic NESHAP (HON) from SOCMI	Y, no change
40 CFR Part 63, Subpart G	NESHAPs for Source Categories; HON from SOCMI for Process Vents, Storage Vessels, Transfer Operations, and Wastewater	Y, no change
40 CFR Part 63, Subpart H	NESHAPs for Source Categories; HON for Equipment Leaks	Y, no change
40 CFR Part 63, Subpart EEEE	NESHAPs for Organic Liquids Distribution (Non-Gasoline)	N
40 CFR Part 63, Subpart ZZZZ	NESHAPs for Stationary RICEs	N
40 CFR Part 63, Subpart DDDDD	NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters	N
40 CFR Part 63, Subpart GGGGG	NESHAPs for Site Remediation	N
40 CFR Part 64	CAM	N

3.1 State Regulations

The following state regulations are potentially applicable to this project.

3.1.1 South Carolina Air Quality Rule 61-62.1 Section II - Permit Requirements

This regulation is applicable to the project because it states that any person who plans to construct, alter, or add to a source of air contaminants, including installation of any device for the control of air contaminant discharges, shall first obtain a construction permit from the Department prior to commencement of construction. This application is being submitted to meet this requirement because the project results in an increase of CO emissions.

3.1.2 South Carolina Air Quality Rule 61-62.5 Standard No. 1

This regulation is applicable to fuel combustion sources and includes emission limits for visible emissions (opacity), sulfur dioxide (SO_2), and PM. This regulation applies to the heater for the #1 OX HPVGTS, which is not affected by the project. Therefore, the proposed project will not change any of the existing limits or requirements for this operation.

3.1.3 South Carolina Air Quality Rule 61-62.5 Standard No. 2

This regulation is applicable to the facility. The CO PSD air quality analysis completed using AERMOD shows the emissions impacts of the project are below the significant impact level. Therefore, no further modeling analysis of emissions for Standard No. 2 is needed per South Carolina's guidance document, *Guidance Concerning Other Information Used for Permitting Requirements in Demonstrating Emissions Do Not Interfere With Attainment or Maintenance of any State or Federal Standard.* Please see Section 5 of this application for more information on the air quality analysis.

3.1.4 South Carolina Air Quality Rule 61-62.5 Standard No. 3

This regulation is shown as an applicable regulation for the HPVGTS catalytic oxidation reactor in the existing Title V permit. However, in the Title V renewal application submitted in January 2012, the following justification was provided to remove this as an applicable regulation:

> *The existing Title V permit has both of the HPVGTS reactors subject to the SC DHEC regulation 61-62.5 Standard 3 (Waste Combustion and Reduction). The HPVGTS is not a combustion system as was intended to be covered by this regulation. However, even if the regulation is potentially applicable to the HPVGTS since the outlet of the*

> *reactors pass through a liquid scrubber prior to being released to the atmosphere it is not possible for either PM or visible emissions from the reactor to be emitted. We request that SC DHEC either agree that the regulation is not applicable to the HPVGTS or that it be exempted since the pollutants of potential concern cannot be emitted by the system.*

In the Statement of Basis for the Dragonslayer project, SC DHEC stated the following:

> *After further review of the applicability of this standard to the catalytic oxidizers, the BAQ has determined that the two oxidizers are still considered to be Industrial Incinerators as defined by this standard, and therefore continues to be subject to this standard.*

The HPVGTS continues to be subject to the requirements, but the operator training requirements have been waived. The proposed change in method of operation for the #1 OX LPA has no impact on this unit.

3.1.5 South Carolina Air Quality Rule 61-62.5 Standard No. 4

The #1 OX/PTA unit has emissions that are subject to this standard. All emission sources, including any fugitives, are subject to 20 percent opacity and PM limits under this standard. The proposed project does not change the process weight for any unit so it does not change any limits or create any new requirements for the affected units under this regulation.

3.1.6 South Carolina Air Quality Rule 61-62.5 Standard No. 5.2

This standard does not apply to this project since no new fuel combustion source is being built and none of the existing fuel combustion sources are being replaced or modified as part of this project.

3.1.7 South Carolina Air Quality Rule 61-62.5 Standard No. 7

This standard will apply to this project since the facility is a PSD major source and the net emissions increase for one PSD pollutant, CO, exceeds the PSD significance threshold. This application is for a PSD permit for the pollutant exceeding the threshold, CO. The results of the PSD analysis are shown in Table B-1 in Appendix B.

3.1.8 South Carolina Air Quality Rule 61-62.5 Standard No. 8

This standard would be applicable to the project since the units are a source of toxic air pollutants (TAPs). However, since both the OX and PTA units are subject to the HON

Maximum Achievable Control Technology (MACT) regulation they are exempt per Standard No. 8 Section I (D) from the regulation. Therefore, air toxics modeling of the revised facility is not required by the regulation.

3.1.9 South Carolina Air Quality Rule 61-62.7

This regulation requires all emissions stacks to be in compliance with good engineering practice (GEP) provisions that set limits on the maximum credit for stack height. All stacks have previously been assessed for compliance with GEP provisions and this project will not change the height any of the stacks.

3.1.10 South Carolina Air Quality Rule 61-62.60

This regulation is applicable to the project since the affected units are subject to 40 CFR Part 60 regulations that are incorporated by reference in this state regulation. This regulation will be met by the facility by meeting the requirements contained in the applicable federal 40 CFR Part 60 regulations. A regulation-specific description of the requirements is contained in subsequent subsections discussing the applicable federal regulations. The proposed project does not create any new requirements or revise any requirements for the facility under this regulation.

3.1.11 South Carolina Air Quality Rule 61-62.61

This regulation is applicable to the unit since the facility in general is subject to 40 CFR Part 61 regulations (Subparts M and FF) that are incorporated by reference in this state regulation. This regulation will be met by the facility meeting the requirements contained in the applicable federal 40 CFR Part 61 regulations. The proposed project does not create any new requirements or revise any requirements for the facility under this regulation.

3.1.12 South Carolina Air Quality Rule 61-62.63

This regulation is applicable to the affected units since they are subject to 40 CFR Part 63 regulations that are incorporated by reference in this state regulation. This regulation will be met by meeting the requirements contained in the applicable federal 40 CFR Part 63 regulations discussed in later sections. The proposed project does subject the #1 OX unit to applicability of any new federal regulations under this regulation. A regulation specific description of the requirements is contained in subsequent subsections.

3.2 Federal Regulations

The following federal regulations are potentially applicable to this project.

3.2.1 40 CFR Part 60, Subpart A

This regulation is applicable to the units and provides general requirements for emissions from source categories. This project will not change the requirements of this regulation to the affected units.

3.2.2 40 CFR Part 60, Subpart Da, Db, and Dc

These regulations are potentially applicable to boilers at the facility; the proposed project does not result in a change or modification to the boilers.

3.2.3 40 CFR Part 60, Subpart Kb

Subpart Kb applies to storage tanks. Since the proposed project does not result in addition of or a change/modification to the tanks, this regulation is not applicable to this project.

3.2.4 40 CFR Part 60, Subpart VV

The #1 OX and PTA units were built before the regulatory applicability date and they have not been modified as defined in the regulation since the applicability date so they are not subject to this regulation. In 2007, BP CR voluntarily agreed to implement a VOC Leak Detection and Repair (LDAR) program equivalent to Subpart VV for the #1 unit as a PSD offset. As part of the Dragonslayer project, the BACT analysis for fugitives concluded that monitoring all equipment leak components according to 40 CFR 63 Subpart H (HON MACT LDAR) would be the applicable BACT. BP currently assumes that all VOCs are HAPs for determining which components will be part of the HON LDAR program. The use of the single LDAR regulation was concluded to be BACT and simplified the monitoring program and recordkeeping. The proposed change in method of operation does not change applicability or requirements under this rule because the change only affects CO emissions from BT-603 and the HPVGTS.

3.2.5 40 CFR Part 60, Subpart VVa

The Dragonslayer project resulted in triggering applicability of this regulation. The facility has chosen an alternative means of compliance allowed within the regulation; the facility will comply with Part 63, subpart H. Owners or operators may choose to comply with the provisions of 40 CFR Part 63, Subpart H, to satisfy the requirements of

§§ 60.482-1a through 60.487a for an affected facility. When choosing to comply with 40 CFR Part 63, Subpart H, the requirements of § 60.485a (d), (e), and (f), and § 60.486a(i) and (j) still apply. The proposed change in method of operation does not change applicability or requirements under this rule because the change only affects CO emissions from BT-603 and the HPVGTS.

3.2.6 40 CFR Part 60, Subpart III

The new #1 OX reactor is subject to this regulation. The Subpart III total resource evaluation (TRE) is above four after the last recovery device for #1 OX. There are no requirements for this regulation other than to keep track of potential changes in the TRE per 40 CFR 60.610(c). Although the reactor is routed to the HPVGTS, the proposed change in method of operation does not affect the #1 OX Reactor or the associated treatment system; therefore, the TRE under this Subpart is unaffected.

The proposed change in method of operation does not change requirements under this rule because the change only affects CO emissions from BT-603 and the HPVGTS and the TRE is unaffected by CO emissions.

3.2.7 40 CFR Part 60, Subpart NNN

As part of the Dragonslayer project the modifications to the #1 OX DHT caused it to become subject to this regulation. An additional NNN operation (Entrainer Recovery Tower) was also added to the unit with the Dragonslayer project. This new distillation tower vents to the same recovery system as the #1 OX DHT recovery system. The NNN TRE after the last recovery device in the distillation tower vent system is above eight so there are no requirements for this regulation other than to keep track of potential changes in the TRE. The proposed change in method of operation does not affect the NNN regulated sources of the associated treatment system; therefore, the TRE under this Subpart is unaffected.

3.2.8 40 CFR Part 60, Subpart RRR

The regulation specifies that it is applicable to reactors, excluding reactor processes using air as a reactant, that produce one of the chemicals listed in the regulation. Since the #1 OX unit uses air as a reactant, this regulation does not apply.

3.2.9 40 CFR Part 60, Subpart YYY

This regulation has been proposed but has not been finalized. When the regulation is finalized, the applicability to the units and the regulatory requirements will be assessed at that time.

3.2.10 40 CFR Part 60, Subpart IIII and JJJJ

These regulations apply to stationary Reciprocating Internal Combustion Engines (RICE). The project does not add additional RICE or modify existing RICE; thus, this regulation does not apply.

3.2.11 40 CFR Part 61, Subpart M

The facility has asbestos-containing materials (ACM) on the site that must be handled in accordance with this regulation. This project will not change the requirements of this regulation to the facility. The proposed changes are not expected at impact any ACM.

3.2.12 40 CFR Part 61, Subpart V

The facility is not subject to this regulation since it is not subject to any of the Part 61 subparts that reference this regulation.

3.2.13 40 CFR Part 61, Subpart FF

The total annual benzene (TAB) quantity from facility waste has historically been less than 1 megagrams per year (Mg/yr). This project will not affect the facility's TAB quantity. This project will not change the applicable requirements to the facility.

3.2.14 40 CFR Part 63, Subpart A

This regulation is applicable to the unit and provides general requirements for the control of HAPs emissions in various regulations under 40 CFR 63. This project will not change the requirements of this regulation that are applicable to the units.

3.2.15 40 CFR Part 63, Subpart F

This regulation is applicable to the units and provides general requirements for HAP emissions from SOCMI sources. This project will not change the requirements of this regulation to the unit.

3.2.16 40 CFR Part 63, Subpart G

The #1 OX unit is subject to the requirements of Subpart G as set forth in 40 CFR Part 63. This unit is subject to the process vent and wastewater provisions of Subpart G with all the existing sources being HON Group 2 sources. BP CR is currently in compliance with all requirements of Subpart G. The project will not constitute reconstruction as defined in the MACT regulations since the total cost of the project will be substantially less than the 50 percent replacement cost threshold. Therefore, the #1 OX unit will remain an existing source. Emissions of CO do not impact regulatory applicability or limits since CO is not a HAP nor is it regulated as a surrogate for HAPs in the rule.

3.2.17 40 CFR Part 63, Subpart H

The #1 OX unit is subject to the requirements of Subpart H as set forth in 40 CFR Part 63. BP CR is currently in compliance with all presently applicable requirements of Subpart H. Emissions of CO do not impact regulatory applicability or limits since CO is not a HAP.

3.2.18 40 CFR Part 63, Subpart EEEE

The regulation would potentially be applicable to some sources at the facility but they are all subject to the HON regulations. Hence, they are all excluded from this regulation and there are no applicable requirements under this regulation.

3.2.19 40 CFR Part 63, Subpart GGGGG

This regulation is applicable to remediation at the site. There is currently no ongoing remediation at the site. However, if any events occur at the site that trigger remediation, the requirements of this regulation will be applied. Emissions of CO do not impact regulatory applicability or limits since CO is not a HAP.

3.2.20 40 CFR Part 63, Subpart ZZZZ

This regulation applies to stationary Reciprocating Internal Combustion Engines (RICE). The project does not add additional RICE or modify existing RICE; thus, this regulation does not apply.

3.2.21 40 CFR Part 63, Subpart DDDDD

This regulation is potentially applicable to boilers at the facility; the proposed project does not result in a change or modification to the boilers. Furthermore, the #1 OX unit does not have equipment potentially subject to this regulation.

3.2.22 40 CFR Part 64

This regulation specifies the requirements for monitoring to assure compliance with emission limits for applicable pollutant specific emission units. The facility has received a Title V renewal permit including required compliance assurance monitoring (CAM) conditions. The present CAM will not need to be revised due to proposed changes.

Section 4
BACT Analysis for CO

As discussed previously, a BACT analysis must be performed for each modified emission source that emits CO. The only modified source is Equipment ID BT-603, the #1 OX LPA. BP has proposed to voluntarily reduce the CO limit for the HPVGTS, however this unit is not being modified and is therefore not subject to a BACT review.

Per USEPA guidance, the "top-down" approach was used to determine BACT for all applicable emission sources. The top-down BACT process requires that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" alternative is established as BACT unless it can be demonstrated that technical considerations, energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable." If the most stringent technology is eliminated, then the next most stringent technology is considered and so on. The top-down approach follows a 5-step format, as follows:

1. Identification of potential control technologies or techniques
2. Elimination of technologically infeasible options
3. Ranking of the remaining control technologies
4. Evaluation of the remaining control technologies
5. Selection of the control technology that constitutes BACT

This 5-step format was followed in this review; each step is discussed in further detail in the following sections.

The USEPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination. First, the BACT analysis must include consideration of the most stringent available technologies, that is, those which provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of technical feasibility and/or energy, environmental, and economic impacts.

The minimum control efficiency to be considered in a BACT analysis must result in an emission rate less than or equal to any applicable NSPS or National Emission Standard for Hazardous Air Pollutants (NESHAP). In this BACT analysis, the most effective technically feasible controls were evaluated based on an analysis of energy, environmental and economic impacts. Control options were identified by researching the RACT/BACT/LAER Clearinghouse (RBLC), drawing from previous engineering experience, surveying available literature, and reviewing PSD permits for similar projects and processes.

4.1 Control Technology Information

The following is a brief description of each of the control technologies that will be considered. The possible control efficiency for each technology shown in the following descriptions is the upper range for each technology and may not be possible but has been assumed for BACT purposes (*i.e.*, an RTO may not be able to achieve 99 percent in practice).

- **Direct Fired Thermal Oxidizer (DFTO) (Afterburner)** – An afterburner, sometimes referred to as a thermal oxidizer (TO) or DFTO, is a controlled combustion technology for air pollution control of a gaseous stream. Fuel and air are added to a combustion chamber through which the exhaust gases pass to maintain a high minimum operating temperature and decompose the carbon containing pollutants (*e.g.*, VOC and CO) into carbon dioxide (CO_2) and water (H_2O) before releasing them to the atmosphere. Afterburners have high fuel consumption and require relatively stable flow conditions. They are best suited for smaller processes with moderate to high hydrocarbon loadings. This technology has a possible control efficiency of 95 percent for CO. The operation of a TO will result in an increase in pollutants from natural gas combustion, specifically nitrogen oxides (NOx) and greenhouse gases (GHG), which is an added environmental impact.
- **Regenerative Thermal Oxidizer (RTO)** – This control technology is similar to a DFTO in the manner it controls emissions. The difference in the RTO versus a DFTO is the energy efficiency it achieves by storing heat in ceramic media as the process stream enters and exits the combustion chamber. The exhaust gas enters the first bed where the gas is heated to a desired combustion temperature, then subsequently enters the second bed where heat from combustion is recovered and stored in the bed. The directions of the airflow is reversed every 1 to 3 minutes by a series of valves to alternately store and regenerate the heat – the inlet process stream gets pre-heated and the outlet process stream gives up the heat. The result is a more energy efficient operation than a DFTO. This technology has a possible control efficiency of 95 percent for CO. The operation of a RTO will result in an increase in pollutants from natural gas combustion, specifically NOx and GHG, which is an added environmental impact.
- **Recuperative Thermal Oxidizer (RO)** – This control technology is similar to a DFTO in the manner it controls CO emissions. The difference in the RO versus a DFTO is the energy efficiency it achieves by a primary and/or secondary heat exchanger within the system. A primary heat exchanger preheats the incoming vent stream by recuperating heat from the exiting treated stream. As the incoming air passes on one side of the exchanger heat is transferred to it through the process of conduction from the hot clean air from the combustion chamber passing on the other side of the exchanger. Recuperative oxidizers

are typically applied to flowrates 50,000 standard cubic feet per minute (scfm) or less. This technology has a possible control efficiency of 95 percent for CO. The operation of a RCO will result in an increase in pollutants from natural gas combustion, specifically NOx and GHG, which is an added environmental impact.

- **Catalytic Thermal Oxidizer (CTO)** – This control technology decomposes CO into CO_2 and H_2O at lower temperatures than a DFTO in the presence of a catalyst to promote the reaction. The lower temperatures, typically between 600 °F and 900 °F, will reduce the amount of supplemental heat required for the process and reduce possible natural gas combustion emissions. Catalytic oxidation occurs through a chemical reaction between the CO molecules and a precious-metal catalyst bed that is internal to the oxidizer system. A catalyst is a substance that is used to accelerate the rate of a chemical reaction, allowing the reaction to occur in a much lower normal temperature range. This technology has a possible control efficiency of 95 percent for CO. The operation of a CTO will result in an increase in pollutants from natural gas combustion, specifically nitrogen oxides, which is an added environmental impact. An additional disadvantage is the disposal of the spent catalyst. Depending on the catalyst type, the spent catalyst may require disposal in an approved hazardous waste disposal site. In addition, Section 3, Chapter 2.2.3 of the EPA Air Pollution Control Cost Manual (EPA/452/B-02-001) states that packaged catalytic oxidizers are limited in size to less than 20,000 scfm to be able to skid-mount and easily install on a pad foundation Field erected catalytic units are typically limited in size to less than 50,000 scfm. This is primarily due to the practical limits of installing and supporting the catalyst bed.
- **Flare** – A gas flare, alternatively known as a flare stack, is an open air gas combustion device used for burning off flammable gas that will be released to the atmosphere. During combustion, CO reacts with atmospheric oxygen to form CO_2 and H_2O. The vent stream being treated must contain a minimum British thermal units/standard cubic feet (Btu/scf) value to maintain combustion or a supplemental fuel must be added to meet the minimum. The control requirements in 40 CFR 60.18 states a flare shall only be used as a control device if the vent stream being combusted has a net heating value of at least 300 Btu/scf if the flare is steam- or air-assisted or 200 Btu/scf if the flare is unassisted. This is to prevent very low Btu vent streams from blowing out the flare flame. Additionally, § 60.18 requires that a flame be present at all times. This control technology has a disadvantage of potentially producing as many CO emissions as it would destroy so it may not be a feasible technology for CO control.
- Good Design and Operating Practices - Good design includes process and mechanical equipment designs which are either inherently lower polluting or are designed to minimize emissions. Good operating practices include operating methods and procedures to minimize emissions and may include a combination of control methods outlined in this section. Good design and operating practices are intended to minimize CO formation rather than provide "end-of-pipe" removal or control as the other add-on control

technologies described above. Therefore, for the purposes of this analysis, a control efficiency of zero is assumed for good design and operating practices.

4.2 Best Available Control Technology Analysis for CO Emissions from Low Pressure Absorbers

The #1 OX LPA is a recovery device for several process streams in the unit. The LPA recovers the acetic acid in the inlet streams and recycles it into the process so it eventually reaches the reactor system. This is a valuable material that acts as the solvent for the process and any loss from the LPA outlet must be replaced by purchase of fresh acetic acid. Part of the optimization of the manufacturing process is to minimize the loss of acetic acid. The CO is produced in the reactor by unwanted side reaction of oxygen with the acetic acid solvent which causes the loss of the valuable acetic acid that must be replaced and the diversion of the oxygen from the desired reaction to produce TA. The LPA does not recover any of the CO which is a contaminant and diluent for the process and would adversely impact the process if recycled to the unit. This analysis will be based on add-on controls to the outlet of the LPA recovery device.

4.2.1 Identification of Control Technologies

The RBLC database was queried for emission sources and control devices of CO that are used in the process types 64.003 (SOCMI process vents) and 64.999 (other SOCMI processes). The results of the RBLC search are shown in Appendix C[1]. The search returned seven facilities and nine processes for BACT in these industrial categories. The following control methods were identified from the search:

- CTO
- Flare
- Good Combustion Practices
- Good Design and Operating Practices

Good design, combustion, and/or operating practices were the most common form of CO control methods found in the RBLC database for process types 64.003 and 64.999. The #1 OX LPA is not a combustion source; therefore Good Combustion Practices will not be considered in this review. In addition to the RBLC database, other resources for control technologies were reviewed, such as *EPA Air Pollution Control Technology Fact*

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[1] The database was searched on October 30, 2017. The permit date search period was January 1, 2007 through October 30, 2017.

Sheets; EPA Air Pollution Control Cost Manual Sixth Edition, EPA/452/B-02-001, January 2002; and NSPS and NESHAPs standards. The review indicated that control equipment is typically not employed to reduce CO emissions from non-combustion sources. Regardless, in addition to those identified in the RBLC database the following control equipment may also be effective in the reduction of CO emissions from the #1 OX LPA:

- DFTO
- RTO
- RO

4.2.2 Elimination of Infeasible Control Options

DFTO, RTO, RO, and CTO

Oxidation systems are a technically feasible control option for the #1 OX LPA. All four system types (DFTO, RTO, RO, and CTO) will be considered in this evaluation. Additionally, the #1 OX HPVGTS is equipped with a CTO. In addition to a new CTO, routing the emissions from the LPA to the existing HPVGTS CTO will also be considered technically feasible.

Flare

As noted previously, the gases controlled by a flare must have a minimum net heating value of 200 Btu/scf if the flare is unassisted and 300 Btu/scf is the flare is steam- or air-assisted. The exhaust flowrate from the #1 OX LPA stack (Stack ID O-3) is approximately 3,300 cfm. Assuming the exhaust gas has the minimum heating value of 200 Btu/scf, this would equate to 39.6 million Btu per hour (MMBtu/hr). Using an emission factor of 0.37 pounds of CO per MMBtu from AP-42's Table 13.5-1, the flare would generate 14.6 pounds per hour of CO. Thus, the flare would generate as much CO as it was controlling. If the exhaust stream didn't have the necessary heating value, supplemental fuels could be added to achieve complete combustion. The addition of supplement fuels such as natural gas or propane would only increase the amount of CO emissions being generated by the flare. Therefore, because there would not be an actual reduction in the amount of CO emissions a flare will not be considered a technically feasible control option for the #1 OX LPA.

Good Design and Operating Practices

Good design and operating practices are a technically feasible option for the #1 OX LPA and were the most common control method identified in the RBLC database.

4.2.3 Ranking of Remaining Control Technologies

The identified control strategies for CO emissions are ranked as follows:

CONTROL OPTION	EFFICIENCY (%)
DFTO	95
CTO	95
Existing HPVGTS CTO	95
RTO	95
RO	95
Good Design and Operating Practices	NA

4.2.4 Evaluation of Most Effective Control Technologies

The BACT analysis is a three-part investigation that includes economic, energy, and environmental impacts. Each of the remaining options was reviewed with respect to the impacts to determine if they meet BACT requirements.

Economic Analysis

The economic analysis is composed of a calculation of each the technically feasible control technologies' annual cost effectiveness (ACE) based on a comparison of the cost of each feasible control technology in terms of cost per mass of pollutant removed. In general, technologies with excessive costs per ton of pollutant removed are considered excessive in most cases and the installation of that technology would not be deemed economically feasible.

Preliminary budget-level ACE estimates were developed for the application of each of the oxidation systems as add-on CO emission control technologies. The cost estimates for the oxidation technologies were based on guidance adapted from the USEPA Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (EPA 452/B-02-001, Sixth Edition; January 2002). The capital and operating expenses were obtained from using the *EPA Air Pollution Control Cost Manual Sixth Edition*, EPA/452/B-02-001 or *EPA's Air Pollution Control Fact Sheets*. The ACE is estimated according to the following formula:

ACE = (Control Option Annualized Cost)/(Baseline emission rate - Control option emission rate)

The baseline CO emissions from #1 OX LPA is 61.3 tpy. The #1 OX LPA emission rate was used as the baseline emission rate for the BACT analysis. This emission rate is used to determine the ACE for each add-on control option.

As an example ACE calculation, assume the control efficiency of an option is 95 percent. The (baseline emission rate-control option emission rate) for each option is equal to {61.3 tpy – [61.3 tpy X (1-95%)]} or 58.2 tons on an annual basis. This emission rate is used to determine the ACE in units of dollars per ton of pollutant removed ($/ton) for the specific control option.

The ACE can be estimated from the above capital and annual operating costs by annualizing the capital cost (multiplying by a factor of 0.10 to simulate a 20-year equipment life and an 8 percent interest rate). This value is added to the annual operating cost and the sum is divided by the product of the control efficiency and the uncontrolled emission rate.

All the technically feasible options will require additional equipment to raise the pressure on the LPA outlet, which is almost at atmospheric pressure, to allow it to flow through any of the add-on control devices. The installation of the additional equipment to increase the pressure of the process stream (*i.e.*, fan/blower) to allow it to flow through a control device will in turn increase the capital cost for the proposed configuration.

Table 4-5 provides a summary of the capital cost, annualized operating cost, and ACE values for each of the add-on control options. Supporting calculations for the cost analysis is provided in Appendix D, BACT Analysis Cost Information.

Since the ACE value for the options are all greater than $6,000 per ton of CO removed, add-on controls are not economically feasible. The ACE values are compared to Georgia PSD applications for Johns Manville-Winder and Houston American Cement which indicated that ACE values of $5,800-9,696 were not cost effective for CO control.

Energy Analysis

An energy impact analysis is used to identify if the technically feasible control options result in any significant or unusual energy penalties or benefits. The feasible control options have been evaluated and it has been determined that no unusual energy penalties exist beyond what was considered in the economic analysis described in the previous section. Each of the combustion options will require a substantial amount of increased fuel gas consumption. An analysis of energy benefits was also considered; the various options do not result in any energy benefit for the BP facility.

Environmental Analysis

A review of the control options with respect to the environment was conducted to determine if any of the options created any adverse environmental impacts. All of the add-on control options results in significant increases in energy usage from powering fans with electricity to heating the vent stream with natural gas. Thermal options (DFTO, RTO, and RO) will also generate significant quantities of products of combustion such as CO, NO_X, and GHG that make these control options less environmentally beneficial. Additionally, the spent catalyst from the CTO may be considered a hazardous waste and require special disposal considerations. The proposed technically feasible options are not environmentally beneficial and in some cases create byproducts such as secondary air emissions.

The combustion controls emit NO_X as a byproduct of CO destruction, thus there is an inverse relationship for these two pollutants when controls are applied. Currently, SC ambient air quality monitors indicate that there is a large margin between CO concentrations in ambient air and the NAAQS. CO data available from SC DHEC's website shows that average 1-hour concentrations are less than 15% of the standard and average 8-hour concentrations are less than 3% of the standard. For NO_X, the 1-hour 98th percentile is nearly 40% of the standard at the Charleston monitoring station. Although CO and NOX are both well within the NAAQS, NO_X is an important contributor to ozone formation; studies indicate that SC is "NO_X limited". Ozone values across SC are in compliance with the NAAQS, however, values range from 80% to almost 100% of the NAAQS. Thus, any decrease in CO that results in an increase in NOX is counterproductive to maintaining compliance with ozone standards.

For these reasons, BP has concluded that control of CO emissions from the BT-603 process may have significant environmental impacts; thus, further control of CO is not warranted at this time.

Table 4-5
LPA CO BACT Analysis

CONTROL OPTION	EMISSION REDUCTION (tpy)	TOTAL CAPITAL COST ($)	ANNUALIZED OPERATING COST ($)	AVERAGE COST EFFECTIVENESS ($/ton)	INCREASED ENERGY USAGE ($/yr)	ADVERSE ENVIRONMENTAL IMPACTS?
DFTO	58.2	$ 798,000	$ 505,000	$ 8,680	$ 329,000	Yes
CTO	58.2	$ 1,152,000	$ 338,000	$ 5,810	$ 133,000	Yes
Existing HPVGTS CTO	58.2	$ 830,000	$ 1,170,000	$ 20,100	$ 1,428,000	Yes
RTO	58.2	$ 1,180,000	$ 353,000	$ 6,070	$ 189,000	Yes
RO	58.2	$ 1,551,000	$ 408,000	$ 7,010	$ 97,000	Yes

4.2.5 Selection of Best Available Control Technology

Based on the energy, environmental, and economic impacts associated with the technically feasible control options, BP has concluded that the add-on control equipment options are not economically or environmentally feasible. The proposed BACT for CO emissions from the LPA is good operating practices with no add-on control. This proposed BACT is consisted with the RBLC database entries for similar sources. BP proposes a BACT limit for CO emissions from the #1 OX LPA of 14 lbs/hr based on a 30 day average. The monitoring for CO emissions will be based on performance testing of the LPA CO emissions every 36 months in accordance with EPA's Method 10B or an alternative method approved by the state. If the results of the test show that emissions are less than 50% of the limit, BP requests that repeat testing be conducted once every five years. Since the HPVGTS and BT-603 are usually tested during the same mobilization event, BP requests that the testing frequency for the HPVGTS be modified to be consistent with the proposed BT-603 testing frequency.

Section 5
Air Quality Analysis

5.1 Background

This project triggers PSD permitting requirements for CO and therefore an air quality analysis must be conducted to support this application. Modeling is only required for the pollutant subject to PSD review (CO). The project does not involve any new sources of CO emissions. The proposed changes will allow the facility to operate in a more efficient manner.

The project is located at the BP-Cooper River facility (see Figure 5-1). Figures 5-2 and 5-3 provide a representation of the facility's boundary and project source locations.

5.2 Modeling Protocol

As part of the Dragonslayer project, a modeling protocol was submitted to SC DHEC for review on January 8, 2013. The protocol and subsequent modeling was approved by SC DHEC; the modeling performed for this application follows the previously submitted protocol. The following section summarizes the approach to the air quality modeling analysis. The air modeling information is included in Appendix F.

5.2.1 Model Selection

Air dispersion modeling was performed using the American Meteorological Society/ Environmental Protection Agency Regulatory Model AERMOD (AERMOD). In this application the version used has been updated to the most current form (Version 16216r). AERMOD is the preferred model for conducting air quality analyses for areas within 50 km of the emission source. AERMOD also includes the Plume Rise Model Enhancements (PRIME) algorithms for building downwash.

5.2.2 Information on Urban/Rural Characteristics

The site is located north of the City of Charleston in a predominantly rural area. The AERMOD model was utilized in its non-urban configuration.

5.2.3 Surrounding Terrain

The area surrounding the facility has only minor terrain relief. However following standard AERMOD guidelines, terrain elevations for grid receptors were included in the

AERMOD modeling through use of the AERMAP terrain processor and applicable National Elevation Data (NED) files. NED files with NAD83 coordinates were used.

5.2.4 Good Engineering Practice Stack Heights and Building Downwash

No stack in the modeling analysis for this project meets the definition of formula GEP stack height so the BPIP PRIME computer algorithm was used to determine wind directionally dependent building dimensions for use in the AERMOD analysis. A BPIP input file for the facility is included in the modeling files submitted with this application.

5.2.5 Cavity Analysis

Cavities are eddies or areas of nearly stagnant air created on the leeward side of a building. The BP CR facility has the potential to produce cavity impacts. The AERMOD model, with building input data prepared using BPIPPRM algorithm, was used to directly evaluate cavity concentrations.

5.2.6 Meteorological Data

The meteorological data set used in this analysis is from the SC DHEC Website (files CHS _0206_v16216.SFC and CHS- _0206_v16216.pfl). These data are from the Charleston meteorological station. Specifically for this project, SC DHEC has updated the meteorological data set with the use of the AERMET Version 16216 processer.

An assessment was made of the applicability of these meteorological data to a modeling analysis at BP CR. The BP CR site is located less than 10 miles from the Charleston airport (the meteorological observation station). The airport site and the BP CR site are both located about 15 miles from the Atlantic coast. There is only minor terrain relief in this part of South Carolina. The AERSURFACE algorithm was used to assess three basic parameters, albedo, Bowman Ratio, and roughness length on an annual basis for 12 wind sectors (results shown in Tables 5-1 and 5-2). The results in Tables 5-1 and 5-2 show that while there is some degree of similarity for albedo there are differences with Bowen Ratio and surface roughness values between the sites. These differences are typical however for comparing the surface characteristics an observation site at an airport with a site not at an airport. Given the relatively small predicted impacts in comparison to the significant impact levels and considering the proximity of the airport site to the project site, this meteorological data set is considered to be a reasonable choice for this analysis.

Table 5-1
Charleston Meteorological Site AURSURFACE Parameters

```
** Generated by AERSURFACE, dated 13016
** Generated from "southcarolina.bin"
** Center UTM Easting (meters):     589718.0
** Center UTM Northing (meters):   3640551.0
** UTM Zone:  17    Datum: NAD83
** Study radius (km) for surface roughness:   1.0
** Airport? Y, Continuous snow cover? N
** Surface moisture? Average, Arid region? N
** Month/Season assignments? User-specified
** Late autumn after frost and harvest, or winter with no snow: 1,2
** Winter with continuous snow on the ground: 0
** Transitional spring (partial green coverage, short annuals): 3,4
** Midsummer with lush vegetation: 5,6,7,8,9
** Autumn with unharvested cropland: 10,11,12

   FREQ_SECT  ANNUAL 12
   SECTOR   1    0   30
   SECTOR   2   30   60
   SECTOR   3   60   90
   SECTOR   4   90  120
   SECTOR   5  120  150
   SECTOR   6  150  180
   SECTOR   7  180  210
   SECTOR   8  210  240
   SECTOR   9  240  270
   SECTOR  10  270  300
   SECTOR  11  300  330
   SECTOR  12  330  360
**                      Sect     Alb      Bo       Zo
   SITE_CHAR    1         1     0.16     0.70     0.039
   SITE_CHAR    1         2     0.16     0.70     0.050
   SITE_CHAR    1         3     0.16     0.70     0.054
   SITE_CHAR    1         4     0.16     0.70     0.037
   SITE_CHAR    1         5     0.16     0.70     0.029
   SITE_CHAR    1         6     0.16     0.70     0.023
   SITE_CHAR    1         7     0.16     0.70     0.023
   SITE_CHAR    1         8     0.16     0.70     0.038
   SITE_CHAR    1         9     0.16     0.70     0.039
   SITE_CHAR    1        10     0.16     0.70     0.042
   SITE_CHAR    1        11     0.16     0.70     0.028
   SITE_CHAR    1        12     0.16     0.70     0.022
```

Table 5-2
BP Cooper River Site AURSURFACE Parameters

```
** Generated by AERSURFACE, dated 13016
** Generated from "southcarolina.bin"
** Center UTM Easting (meters):    604442.0
** Center UTM Northing (meters):  3648960.0
** UTM Zone:  17    Datum: NAD83
** Study radius (km) for surface roughness:   1.0
** Airport? N, Continuous snow cover? N
** Surface moisture? Average, Arid region? N
** Month/Season assignments? User-specified
** Late autumn after frost and harvest, or winter with no snow: 1,2
** Winter with continuous snow on the ground: 0
** Transitional spring (partial green coverage, short annuals): 3,4
** Midsummer with lush vegetation: 5,6,7,8,9
** Autumn with unharvested cropland: 10,11,12

   FREQ_SECT  ANNUAL 12
   SECTOR   1    0   30
   SECTOR   2   30   60
   SECTOR   3   60   90
   SECTOR   4   90  120
   SECTOR   5  120  150
   SECTOR   6  150  180
   SECTOR   7  180  210
   SECTOR   8  210  240
   SECTOR   9  240  270
   SECTOR  10  270  300
   SECTOR  11  300  330
   SECTOR  12  330  360
**                      Sect     Alb       Bo       Zo
   SITE_CHAR     1        1     0.14     0.33     0.787
   SITE_CHAR     1        2     0.14     0.33     0.777
   SITE_CHAR     1        3     0.14     0.33     0.839
   SITE_CHAR     1        4     0.14     0.33     0.855
   SITE_CHAR     1        5     0.14     0.33     0.791
   SITE_CHAR     1        6     0.14     0.33     0.420
   SITE_CHAR     1        7     0.14     0.33     0.476
   SITE_CHAR     1        8     0.14     0.33     0.520
   SITE_CHAR     1        9     0.14     0.33     0.351
   SITE_CHAR     1       10     0.14     0.33     0.569
   SITE_CHAR     1       11     0.14     0.33     0.690
...SITE_CHAR     1       12     0.14     0.33     0.753
```

5.2.7 Model Receptors

Receptors were placed along the fence at a spacing of 25 meters to 50 meters out to a distance to define the maximum predicted impacts as being within the interior of the grid. The maximum predicted impacts were on the facility boundary in an area of 25 to 50 meter spacing. Figure 5-4 contains a representation of the receptors used in the analysis.

5.2.8 Visibility Impairment Analysis

This project triggers PSD air quality evaluation requirements for CO only. This pollutant is not typically understood to affect visibility so no visibility impairment assessment is needed or was undertaken.

5.2.9 Toxic Air Pollutant Analysis

The facility is not subject to a South Carolina Standard No. 8 modeling evaluation because processes at the facility that emit Standard No. 8 pollutants are subject to MACT requirements which can be substituted to meet Standard No. 8 requirements.

5.3 Class I Area Impact Analysis

The responsible FLMs for the Cape Romain Class I area have been contacted and provided updated information concerning the proposed BP CR project.

As indicated earlier, this project triggers PSD requirements for CO only. Project net emission increases of nitrogen dioxide (NO_2), VOC, SO_2, and PM (PM_{10} and $PM_{2.5}$) do not exceed PSD significance levels. The tools available for a visibility analysis (such as VISCREEN) do not include inputs for CO emissions, so it is assumed this project would have minimal impacts on visibility in the Class I area.

5.4 Significance Modeling Results for CO

Emissions of CO are summarized in Table 5-3. The basis for these emission estimates are presented in other parts of this application with supporting calculations found in Appendix B. Figure 5-3 shows the location of the project sources.

It should be noted that while Table 5-3 shows an offset emission source with a negative emission rate for #1 OX DHT Overhead Scrubber (BT-702), this source would have operated at that rate only sporadically. Consequently a separate source group was used that included only the stacks with the positive emissions rates. These results are shown below. The initial modeling analysis showed the following worst-case impacts.

Table 5-3
CO Emission Sources with Parameters

MODEL ID	DESCRIPTION	X (m)	Y (m)	ELEV. (m)	PROJECT CO EMISSIONS (g/s)	PROJECT CO EMISSIONS (lb/hr)	STACK HEIGHT (m)	TEMP. (K)	VEL. (m/s)	DIAM. (m)
BT_702(1)	DHT Overhead Scrubber	604491.1	3649074	10.02	-10.96	-87.0	10.67	305	21.3	0.304
BT_603	LPA	604628.1	3649119	8.67	1.764	14.0	21.5	322	3.4	0.762
HPVGTS-1	HPVGTS-1	604666.1	3649104	8.81	9.072	72.0	30.48	350	79.8	0.91
DT_302	LPA	604521.3	3648901	8.75	0.437	3.5	24.4	308	0.98	1.07
HPVGTS-2	HPVGTS-2	604642.3	3648896	8.92	9.45	75.0	41.46	333	29.87	1.3
N1PTASSR	#1 PTA Crystallizer	604501	3649204	8.67	3.024	24.0	28.65	373	5.18	1.07
N2PTACSC	#2 PTA Crystallizer	604447	3648955	8.67	2.52	20.0	22.86	373	5.03	1.07
N2OXUNIT	#2 Ox Unit HPVGT	604585	3648969	8.67	0.156	1.24	41.09	639	21.34	0.881

(1) Source would historically operate at the listed emission rates only occasionally. An analysis was completed with all sources operating and another with only the stacks with the positive emission rates.

- 1-hour CO Highest Predicted Impact 243 micrograms per cubic meter (μg/m^3)
- 8- hour CO Highest Predicted Impact 120 μg/m^3

These predicted values are below the PSD significant impact thresholds of 2,000 μg/m^3 (1-hour) and 500 μg/m^3 (8-hours). Therefore, no further modeling analysis of emissions for Standard No. 2 is needed.

5.5 Preconstruction Monitoring Requirements

The worst case predicted concentrations are also below the Preconstruction Monitoring threshold of 575 μg/m^3.

No further analysis is therefore needed for CO for this project.

5.6 Analysis for Ozone Impact

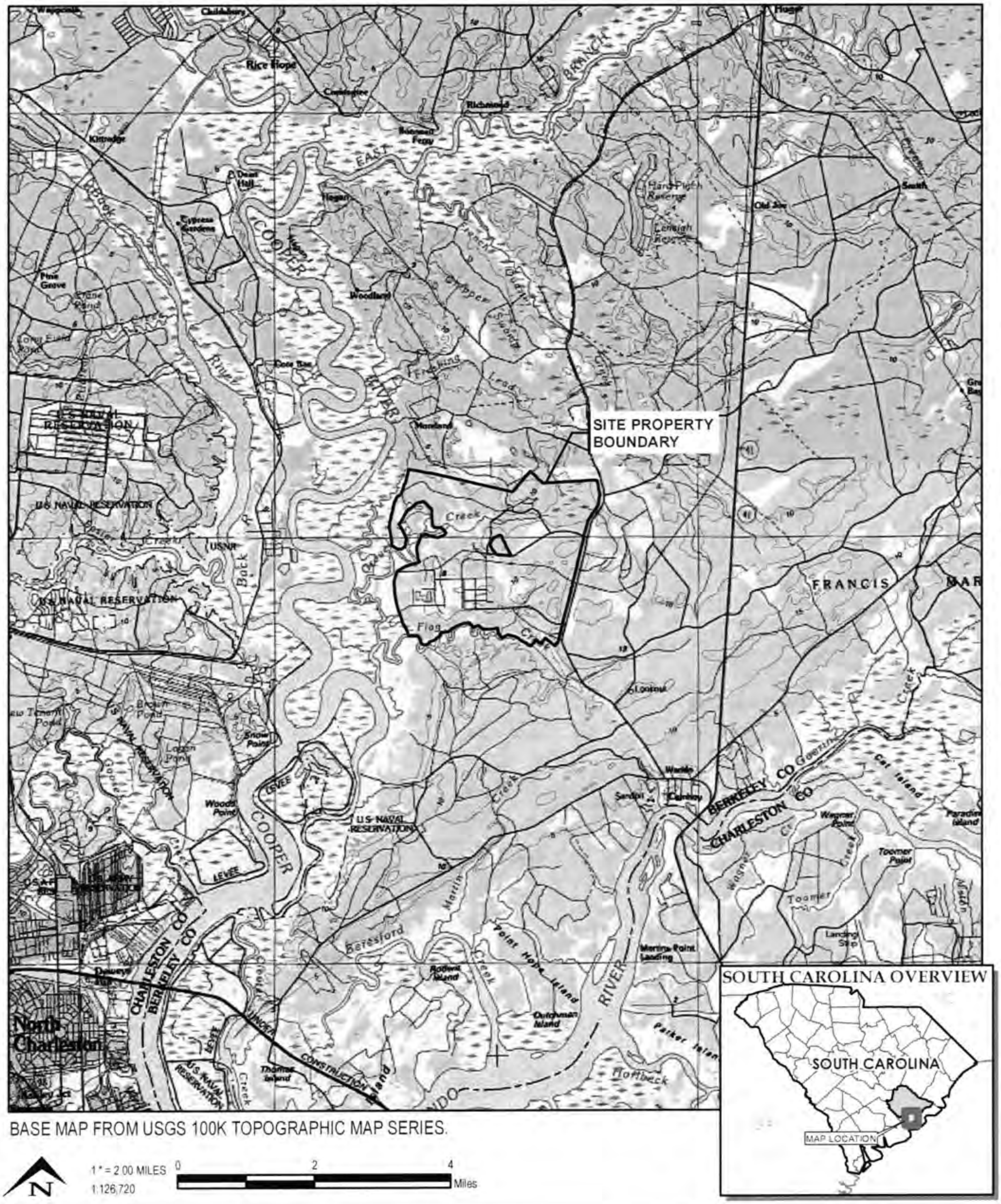
In this application and requested permit revision, there is no request to increase the emissions of VOCs or NOx for the project, so no impact on ozone concentrations beyond what was previously approved is requested and no further analysis is warranted.

5.7 Preconstruction Monitoring for Ozone

The project emissions increase is for CO only; CO is not an ozone precursor. No change in ozone precursors will occur, so no preconstruction monitoring of ozone is needed for the project.

Printed By: jpapez on never, never

TRC - GIS



BASE MAP FROM USGS 100K TOPOGRAPHIC MAP SERIES.

TRC

50 International Drive,
Suite 150,
Patewood Plaza Three
Greenville, SC 29615

BP COOPER RIVER
SOUTH CAROLINA

FIGURE 5-1
SITE LOCATION MAP

DRAWN BY:	PAPEZ J
APPROVED BY:	FOX D
PROJECT NO:	187464
FILE NO.	187464-003slm.mxd
DATE:	JANUARY 2013

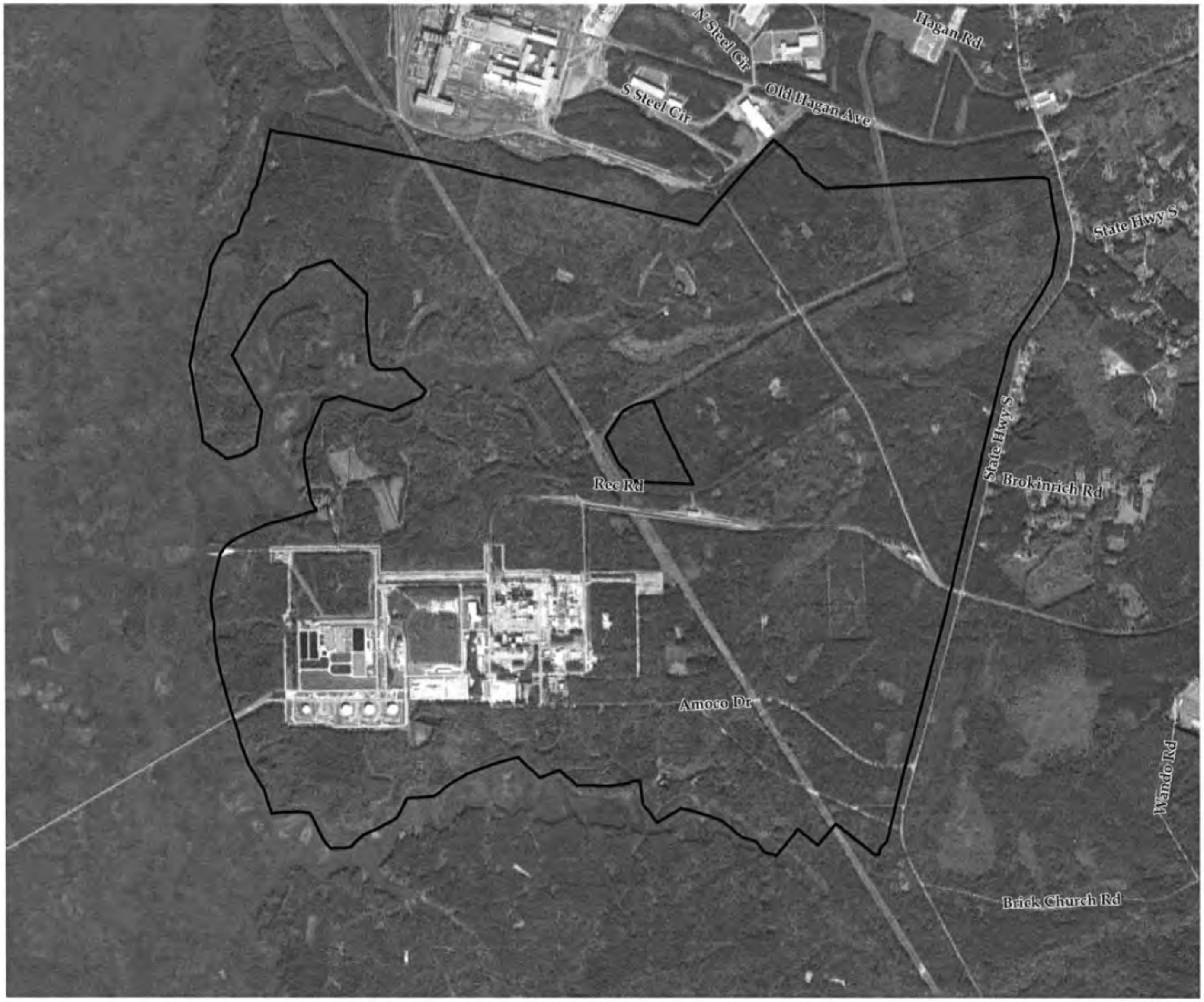
E:\BP\CooperRiverSC\2012_187464\187464-003slm.mxd

LEGEND

APPROXIMATE FACILITY BOUNDARY

NOTES

1. BASE MAP IMAGERY FROM ESRI WEB SERVICE BASEMAP LAYER, "WORLD IMAGERY".



0 3,000 6,000 FEET

1 INCH = 3,000 FEET

1:36,000

N

TRC - GIS

TRC

50 International Drive
Suite 150
Patewood Plaza Three
Greenville, SC 29615

BP COOPER RIVER
SOUTH CAROLINA

FIGURE 5-2
SITE MAP - FACILITY BOUNDARY

DRAWN BY:	PAPEZ J
APPROVED BY:	FOX D
PROJ. NO.:	187464
FILE NO.:	187464-001.mxd
DATE:	JANUARY 2013

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Saved By: JPAPEZ on 1/8/2013, 08:30:39 AM

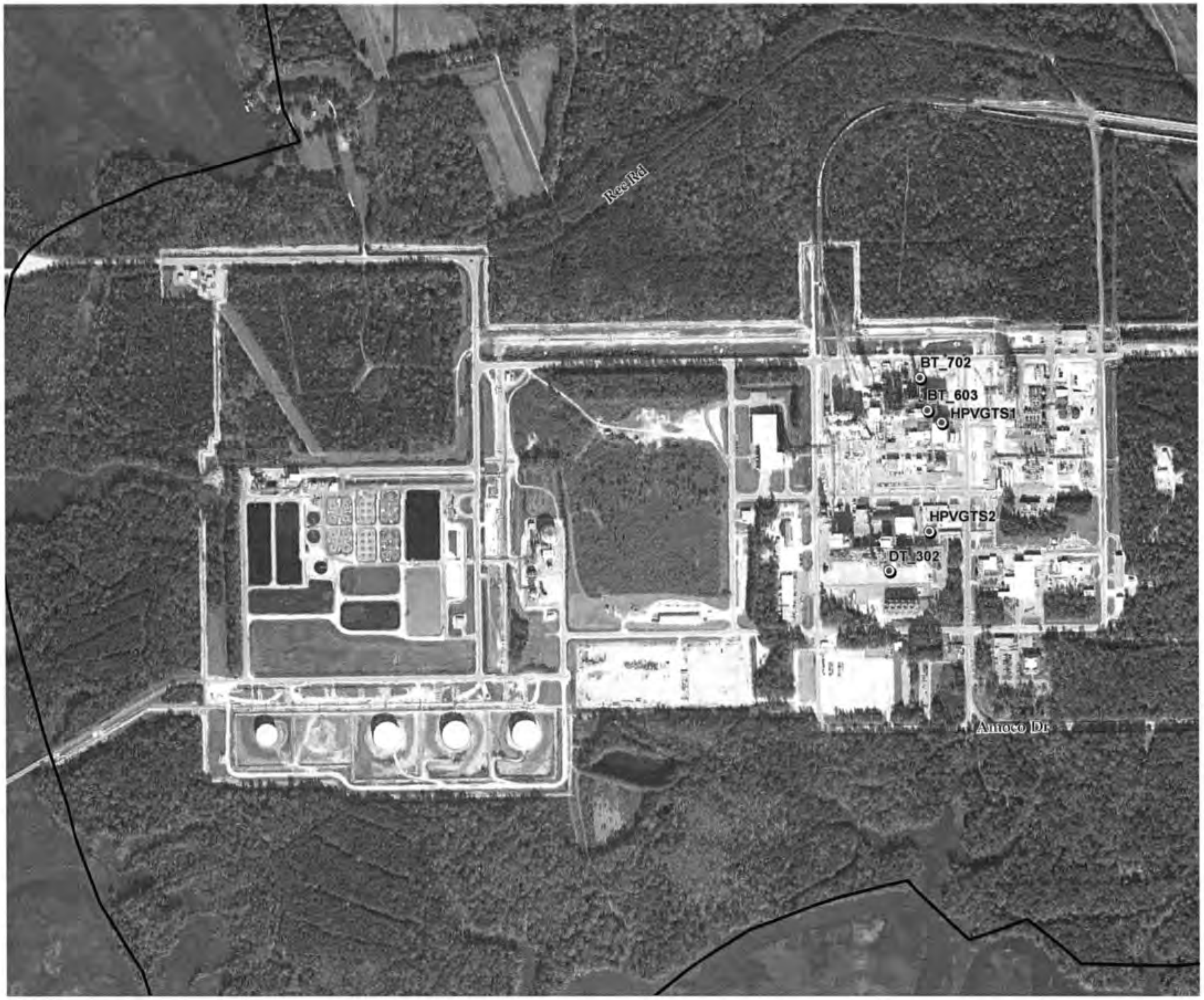
LEGEND

▭ APPROXIMATE FACILITY BOUNDARY

◉ STACK LOCATION

NOTES

1. BASE MAP IMAGERY FROM ESRI WEB SERVICE BASEMAP LAYER, "WORLD IMAGERY".



0 1,000 2,000 FEET

1 INCH = 1,000 FEET

1:12,000

N

TRC - GIS

TRC

50 International Drive
Suite 150
Patewood Plaza Three
Greenville, SC 29615

BP COOPER RIVER
SOUTH CAROLINA

FIGURE 5-3
PROJECT EMISSION SOURCES

DRAWN BY:	PAPEZ J
APPROVED BY:	FOX D
PROJ. NO.:	187464
FILE NO.:	187464-002.mxd
DATE:	JANUARY 2013

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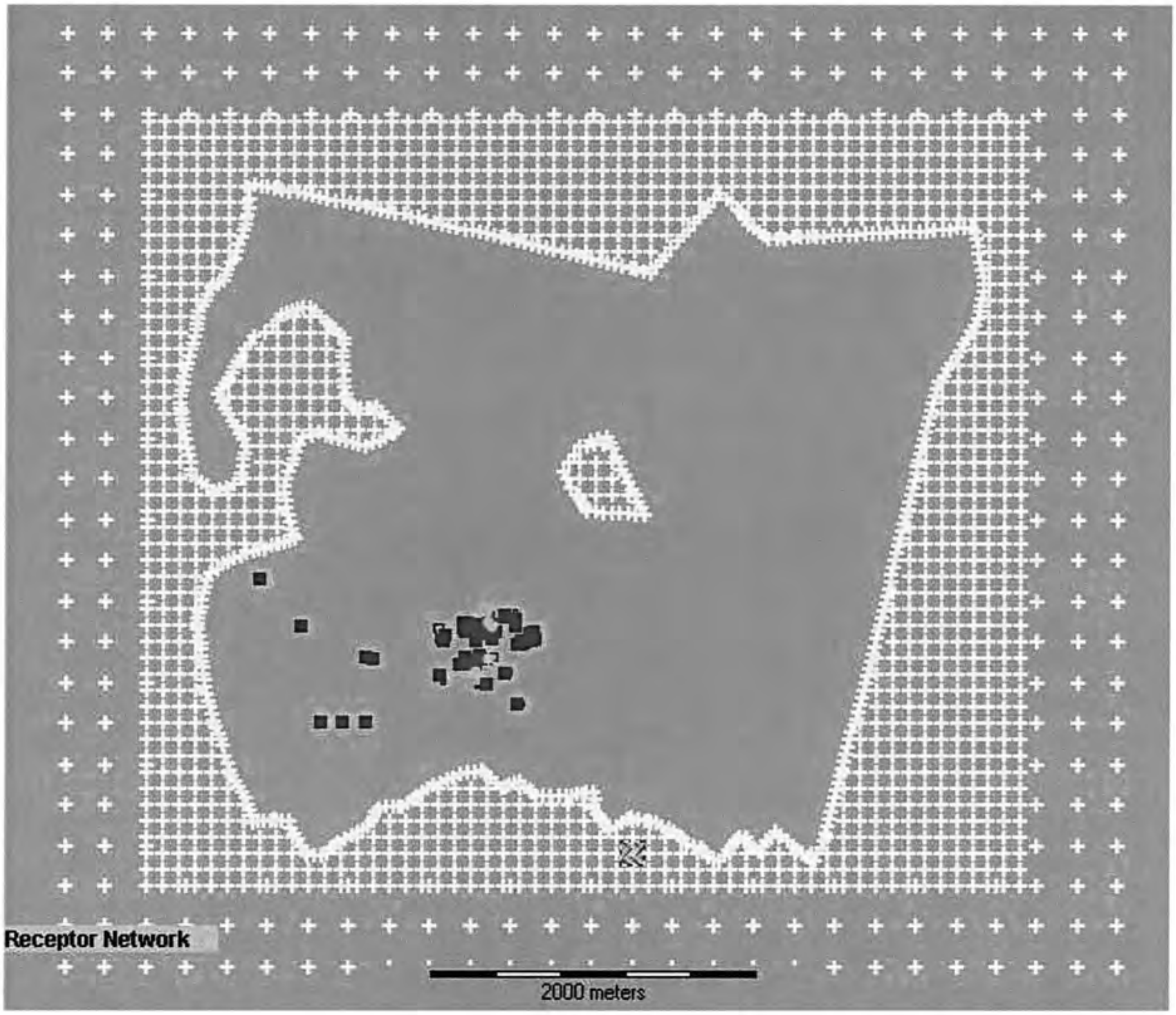
Saved By: JPAPEZ on 1/8/2013, 08:30:26 AM

Figure 5-4
Receptor Network



Section 6
Additional Impacts Analyses

The provisions of South Carolina Regulation 62.5, Standard No. 7 require that additional environmental impact analyses be performed to determine the impairment to visibility, soil, and vegetation that would occur as a result of construction and operation of a major source or a modification to a major source. These regulatory provisions also require that analyses be performed to determine the general commercial, residential, industrial, and other growth associated with operation of a major source or modification, as well as the air quality impact projected for the area as a result of such growth.

6.1 Visibility/Regional Haze

As indicated earlier in this report, the project is projected to have insignificant impact on regional visibility or haze due to the fact that the project triggers PSD requirements only for CO. CO is not a variable that is input in models to determine visibility impacts (such as in the VISCREEN algorithm).

6.2 Associated Growth Impacts

The proposed modification at the BP CR facility is not anticipated to result in any significant increase in full-time employment (an associated increase in traffic flow) at the facility. There is not any construction activity related to the project that would result in a temporary increase in local traffic due to construction related jobs and associated traffic.

6.3 Impacts on Soil and Vegetation

According to EPA's final report on "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" (EPA 450/2-81-078), vegetation effects are possible for CO concentrations above 1000 ppm. The maximum predicted CO impact for this project is 242 ug/m^3 (equal to 0.22 ppm). Consequently, no effects on soils or vegetation would be expected from the project.

6.4 Air Quality Impact

As part of this application a dispersion modeling analysis was performed to demonstrate that the project CO emissions will result in predicted ambient air quality impacts below the National Ambient Air Quality Standards and PSD allowable increments. The results of this analysis are summarized in Section 5 of this application.

Appendix A
SC DHEC Permit Application Forms

dhec

Bureau of Air Quality
Expedited Review Request Instructions
Construction Permits
Page 1 of 2

RECEIVED
MAR 30 2018
BUREAU OF AIR QUALITY
pw

APPLICATION IDENTIFICATION		
Facility Name *(This should be the name used to identify the facility)*	SC Air Permit Number (8-digits only) *(Leave blank if one has never been assigned)*	Request Date
BP Amoco Chemical Company - Cooper River Plant	0420 - 0029	12/8/2017

PRIMARY AIR PERMIT CONTACT			
Title/Position: Environmental Engineer	Ms.	First Name: Marianne	Last Name: Andrews
E-mail Address: Marianne.Andrews2@bp.com		Phone No.: (843) 800-3478	Cell No.: (804) 518-3726

SECONDARY AIR PERMIT CONTACT *(If the Department is unable to contact the primary air permit contact please provided a secondary contact.)*			
Title/Position: Office Practice Leader	Mr.	First Name: Robert	Last Name: vandenMeiracker
E-mail Address: rvandemeiracker@trcsolutions.com		Phone No.: (864) 787-5261	Cell No.: (864) 787-5261

Check One	Permit Type	Expedited Review Days*	Fee**
☐	Minor Source Construction Permit	30	$3,000
☐	Synthetic Minor Construction Permit	65	$4,000
☐	Prevention of Significant Deterioration (PSD) Not impacting a Class I Area (no Class I modeling required)	120	$20,000
☐	Prevention of Significant Deterioration (PSD) Impacting a Class I Area (Class I modeling required)	150	$25,000
☒	Prevention of Significant Deterioration (PSD) Modification not impacting a Class I Area (Class I modeling required)	120	$TBD
☐	**Concrete** Minor Source Construction Permit Relocation Request	10	$1,500
☐	**Asphalt** Synthetic Minor Construction Permit Relocation Request	15	$3,500

*All days above are calendar days, but exclude State holidays, and building closure dates due to severe weather or other emergencies. Expedited days for asphalt and concrete also exclude weekends.

****DO NOT SEND PAYMENT UNTIL THE APPLICATION HAS BEEN ACCEPTED INTO THE EXPEDITED PROGRAM**. If chosen for expedited review, you will be notified by phone for verbal acceptance into the program. Fees must be paid within five business days of acceptance.

PRIMARY AIR PERMIT CONTACT SIGNATURE
I have read the most recent version of the Expedited Review Program Standard Operating Procedures and accept all of the terms and conditions within. I understand that it is my responsibility to ensure an application of the highest quality is submitted in a timely manner, and to address any requests for additional information by the deadline specified. I understand that submittal of this request form is not a guarantee that expedited review will be granted.

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Signature of Primary Air Permit Contact

3/28/2018
Date

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FACILITY IDENTIFICATION	
SC Air Permit Number (8-digits only) *(Leave blank if one has never been assigned)* 0420 - 0029	Application Date December 8, 2017
Facility Name *(This should be the name used to identify the facility at the physical address listed below)* BP Amoco Chemical Company - Cooper River Plant	Facility Federal Tax Identification Number *(Established by the U.S. Internal Revenue Service to identify a business entity)* SCD084703909

FACILITY PHYSICAL ADDRESS		
Physical Address: 1306 Amoco Drive		County: Berkeley
City: Wando	State: SC	Zip Code: 29492
Facility Coordinates *(Facility coordinates should be based at the front door or main entrance of the facility.)*		
Latitude: 32°58'16.25"N	Longitude: 79°52'43.20"W	☒ NAD27 *(North American Datum of 1927)* Or ☐ NAD83 *(North American Datum of 1983)*

CO-LOCATION DETERMINATION
Are there other facilities in close proximity that could be considered co-located? ☒ No ☐ Yes*
List potential co-located facilities, including air permit numbers if applicable:

**If yes, please submit co-location applicability determination details in an attachment to this application.*

COMMUNITY OUTREACH
What are the potential air issues and community concerns? Please provide a brief description of potential air issues and community concerns about the entire facility and/or specific project. Include how these issues and concerns are being addressed, if the community has been informed of the proposed construction project, and if so, how they have been informed. No potential air issues for this project since there is not increase in the permitted allowable emission rate.

FACILITY'S PRODUCTS / SERVICES	
Primary Products / Services *(List the primary product and/or service)* Purified Terephthalic Acid (PTA)	
Primary SIC Code *(Standard Industrial Classification Codes)* 2869	Primary NAICS Code *(North American Industry Classification System)* 325199
Other Products / Services *(List any other products and/or services)* N/A	
Other SIC Code(s): N/A	Other NAICS Code(s): N/A

AIR PERMIT FACILITY CONTACT *(Person at the facility who can answer technical questions about the facility and permit application.)*			
Title/Position: Enviromental Engineer	Salutation: Ms.	First Name: Marianne	Last Name: Andrews
Mailing Address: 1306 Amoco Drive			
City: Wando		State: SC	Zip Code: 29492
E-mail Address: Marianne.Andrews2@bp.com		Phone No.: 843.800.3478	Cell No.: 804.518.3426

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The signed permit will be e-mailed to the designated Air Permit Contact. If additional individuals need copies of the permit, please provide their names and e-mail addresses.	
Name	**E-mail Address**
Robert vandenMeiracker, TRC	rvandenmeiracker@trcsolutions.com

CONFIDENTIAL INFORMATION / DATA

Does this application contain confidential information or data? ☐ No ☒ Yes*

If yes, include a sanitized version of the application for public review and **ONLY ONE COPY OF CONFIDENTIAL INFORMATION SHOULD BE SUBMITTED*

LIST OF FORMS INCLUDED

(Identify all forms included in the application package)

Form Name	Included (Y/N)
Expedited Review Request (DHEC Form 2212)	☒ Yes ☐ No
Equipment/Processes (DHEC Form 2567)	☒ Yes
Emissions (DHEC Form 2569)	☒ Yes
Regulatory Review (DHEC Form 2570)	☒ Yes
Emissions Point Information (DHEC Form 2573)	☒ Yes ☐ No (If No, Explain)

OWNER OR OPERATOR

Title/Position: Plant Manager	Salutation: Mr.	First Name: John	Last Name: Harvey
Mailing Address: 1306 Amoco Drive			
City: Wando		State: SC	Zip Code: 29492
E-mail Address: John.Harvey@bp.com		Phone No.: 843.881.5201	Cell No.:

OWNER OR OPERATOR SIGNATURE

I certify, to the best of my knowledge and belief, that no applicable standards and/or regulations will be contravened or violated. I certify that any application form, report, or compliance certification submitted in this permit application is true, accurate, and complete based on information and belief formed after reasonable inquiry. I understand that any statements and/or descriptions, which are found to be incorrect, may result in the immediate revocation of any permit issued for this application.

Signature of Owner or Operator

3/28/2018

Date

PERSON AND/OR FIRM THAT PREPARED THIS APPLICATION

(If not the same person as the Professional Engineer who has reviewed and signed this application.)

Consulting Firm Name: TRC Environmental			
Title/Position: Office Practice Leader	Salutation: Mr.	First Name: Robert	Last Name: vandenMeiracker
Mailing Address: 50 International Drive, Suite 150, Patewood Plaza Three			
City: Greenville		State: SC	Zip Code: 29615
E-mail Address: rvandenmeiracker@trcsolutions.com		Phone No.: 864.787.5261	Cell No.: 864.787.5261
SC Professional Engineer License/Registration No. (if applicable): 28265			

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PROFESSIONAL ENGINEER INFORMATION			
Consulting Firm Name: TRC Environmental			
Title/Position: Office Practice Leader	Salutation: Mr.	First Name: Robert	Last Name: vandenMeiracker
Mailing Address: 50 International Drive, Suite 150, Patewood Plaza Three			
City: Greenville		State: SC	Zip Code: 29615
E-mail Address: rvandenmeiracker@trcsolutions.com		Phone No.: 864.787.5261	Cell No.: 864.787.5261
SC License/Registration No.: 28265			
PROFESSIONAL ENGINEER SIGNATURE			
I have placed my signature and seal on the engineering documents submitted, signifying that I have reviewed this construction permit application as it pertains to the requirements of *South Carolina Regulation 61-62, Air Pollution Control Regulations and Standards*.			

NO. 28265
ROBERT FRANCIS vandenMEIRACKER

Signature of Professional Engineer 3/29/2018
Date

TRC ENGINEERS, INC.
No. 3330

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APPLICATION IDENTIFICATION *(Please ensure that the information list in this table is the same on all of the forms and required information submitted in this construction permit application package.)*		
Facility Name *(This should be the name used to identify the facility)* BP Amoco Chemical Company – Cooper River Plant	SC Air Permit Number (8-digits only) *(Leave blank if one has never been assigned)* 0420 - 0029	Application Date December 8, 2017

PROJECT DESCRIPTION
Brief Project Description (What, why, how, etc.): Change in the method of operation of #1 Ox unit to reduce operating costs by changing the routing of overhead condensers #2 and #3. See permit application Section 2 for more details.

ATTACHMENTS	
☒ Process Flow Diagram	Location in Application: Section 2
☒ Detailed Project Description	Location in Application: Section 2

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EQUIPMENT / PROCESS INFORMATION

Equipment ID Process ID	Action	Equipment / Process Description	Maximum Design Capacity (Units)	Control Device ID(s)	Pollutants Controlled (Include CAS#)	Capture System Efficiency and Description	Emission Point ID(s)
BR-301	☐ Add ☐ Remove ☒ Modify ☐ Other	Reactor	[redacted]	#1 HPVGTS	VOC (N/A) CO (630-08-0) Paraxylene (106-42-3)	100%, closed vent system	O-2/10/15
BT-401	☐ Add ☐ Remove ☒ Modify ☐ Other	HP Absorber	[redacted]	#1 HPVGTS	VOC (N/A) CO (630-08-0) Paraxylene (106-42-3)	100%, closed vent system	O-2/10/15
BT-701	☐ Add ☐ Remove ☒ Modify ☐ Other	Dehydration Tower	[redacted]	N/A	N/A	100%, closed vent system	O-3
BT-603	☐ Add ☐ Remove ☒ Modify ☐ Other	Low Pressure Absorber	[redacted]	N/A	N/A	100%, closed vent system	O-3
	☐ Add ☐ Remove ☐ Modify ☐ Other						

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CONTROL DEVICE INFORMATION

Control Device ID	Action	Control Device Description	Maximum Design Capacity (Units)	Inherent/Required/Voluntary (Explain)	Destruction/Removal Efficiency Determination
	☐ Add ☐ Remove ☐ Modify ☐ Other				
	☐ Add ☐ Remove ☐ Modify ☐ Other				
	☐ Add ☐ Remove ☐ Modify ☐ Other				
	☐ Add ☐ Remove ☐ Modify ☐ Other				

RAW MATERIAL AND PRODUCT INFORMATION

Equipment ID Process ID Control Device ID	Raw Material(s)	Product(s)	Fuels Combusted
#1 Ox	Paraxylene	Terephthalic Acid	Natural gas for #1 HPVGTS

MONITORING AND REPORTING INFORMATION

Equipment ID Process ID Control Device ID	Pollutant(s)/Parameter(s) Monitored	Monitoring Frequency	Reporting Frequency	Monitoring/Reporting Basis	Averaging Period(s)
#1 Ox	VOC & HAP	HON MACT	HON MACT	HON MACT	HON MACT

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APPLICATION IDENTIFICATION *(Please ensure that the information list in this table is the same on all of the forms and required information submitted in this construction permit application package.)*		
Facility Name *(This should be the name used to identify the facility)* BP Amoco Chemical Company - Cooper River Plant	SC Air Permit Number (8-digits only) *(Leave blank if one has never been assigned)* 0420 - 0029	Application Date December 8, 2017

ATTACHMENTS *(Check all the appropriate checkboxes if included as an attachment)*	
☒ Sample Calculations, Emission Factors Used, etc.	☒ Detailed Explanation of Assumptions, Bottlenecks, etc.
☐ Supporting Information: Manufacturer's Data, etc.	☐ Source Test Information
☐ Details on Limits Being Taken for Limited Emissions	☒ NSR Analysis

SUMMARY OF PROJECTED CHANGE IN FACILITY WIDE POTENTIAL EMISSIONS
(Calculated at maximum design capacity.)

Pollutants	Emission Rates Prior to Construction / Modification (tons/year)			Emission Rates After Construction / Modification (tons/year)		
	Uncontrolled	**Controlled**	**Limited**	**Uncontrolled**	**Controlled**	**Limited**
Particulate Matter (PM)	5,394.2	77.1	----	5,394.2	77.1	----
Particulate Matter <10 Microns (PM_{10})	5,356.2	73.0	----	5,356.2	73.0	----
Particulate Matter <2.5 Microns ($PM_{2.5}$)	5,261.6	67.9	----	5,261.6	67.9	----
Sulfur Dioxide (SO_2)	190.9	189.0	----	190.9	189.0	----
Nitrogen Oxides (NO_x)	495.7	324.9	----	495.7	324.9	----
Carbon Monoxide (CO)	14,820.5	1233.0	----	14,820.5	1206.7	----
Volatile Organic Compounds (VOC)	2587.2	576.5	----	2587.2	576.5	----
Lead (Pb)	1.0	1.0	----	1.0	1.0	----
Highest HAP Prior to Construction (CAS #: 106-42-3)	227.9	58.5	----	227.9	58.5	----
Highest HAP After Construction (CAS #: 106-42-3)	227.9	58.5	----	227.9	58.5	----
Total HAP Emissions*	1688.1	128.6	----	1688.1	128.6	----

Include emissions from exempt equipment and emission increases from process changes that were exempt from construction permits.
(*All HAP emitted from the various equipment or processes must be listed in the appropriate "Potential Emission Rates at Maximum Design Capacity" Table)

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POTENTIAL EMISSION RATES AT MAXIMUM DESIGN CAPACITY

Equipment ID / Process ID	Emission Point ID	Pollutants (Include CAS #)	Calculation Methods / Limits Taken / Other Comments	Uncontrolled		Controlled		Limited	
				lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
#1 HPVGTS	O-2/10/15	VOC	See Appendix B	234	1025	4.7	20.5	--	--
#1 HPVGTS	O-2/10/15	CO (630-08-0)	See Appendix B	1758	7700	72.0	315.4	--	--
#1 HPVGTS	O-2/10/15	CO2e(124-38-9)	See Appendix B	9521	41,700	9521	41,700	--	--
BT-603	O-3	VOC	See Appendix B	9.6	42.0	9.6	42.0	--	--
BT-603	O-3	CO (630-08-0)	See Appendix B	14.0	61.3	14.0	61.3	--	--
BT-603	O-3	CO2e(124-38-9)	See Appendix B	283.0	1240	283.0	1240	--	--

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APPLICATION IDENTIFICATION *(Please ensure that the information list in this table is the same on all of the forms and required information submitted in this construction permit application package.)*		
Facility Name *(This should be the name used to identify the facility)* 1. Facility Name: BP Amoco Chemical Company - Cooper River Plant	SC Air Permit Number (8-digits only) *(Leave blank if one has never been assigned)* 0420 - 0029	Application Date December 8, 2017

STATE AND FEDERAL AIR POLLUTION CONTROL REGULATIONS AND STANDARDS
(If not listed below add any additional regulations that are triggered.)

Regulation	Applicable		Include all limits, work practices, monitoring, record keeping, etc.		
	Yes	No	Explain Applicability Determination	List the specific limitations and/or requirements that apply.	How will compliance be demonstrated?
Regulation 61-62.1, Section II(E) Synthetic Minor Construction Permits	☐	☒	Major Source	N/A	N/A
Regulation 61-62.1, Section II(G) Conditional Major Operating Permits	☐	☒	Title V Major Source	N/A	N/A
Regulation 61-62.5, Standard No. 1 Emissions from Fuel Burning Operations	☐	☒	#1 Ox does not contain any 'fuel burning sources'	N/A	N/A
Regulation 61-62.5, Standard No. 2 Ambient Air Quality Standards	☒	☐	CO Modeling summary contained in Section 5 of report.	N/A	N/A
Regulation 61-62.5, Standard No. 3 Waste Combustion and Reduction	☒	☐	HPVGTS: PM and Opacity Limits	None	Only gaseous materials burned
Regulation 61-62.5, Standard No. 4 Emissions from Process Industries	☒	☐	No change in PWR	None	No change
Regulation 61-62.5, Standard No. 5 Volatile Organic Compounds	☐	☒	No sources meet applicability criteria	N/A	N/A
Regulation 61-62.5, Standard No. 5.2 Control of Oxides of Nitrogen	☐	☒	No non-exempt combustion soruces in #1 Ox unit	N/A	N/A

STATE AND FEDERAL AIR POLLUTION CONTROL REGULATIONS AND STANDARDS

(If not listed below add any additional regulations that are triggered.)

Regulation	Applicable		Include all limits, work practices, monitoring, record keeping, etc.		
	Yes	**No**	**Explain Applicability Determination**	**List the specific limitations and/or requirements that apply.**	**How will compliance be demonstrated?**
Regulation 61-62.5, Standard No. 7 Prevention of Significant Deterioration*	☒	☐	Requesting modification to BT-603 Permit Limit	New Limit: 14.0 lb/hr	Stack test
Regulation 61-62.5, Standard No. 7.1 Nonattainment New Source Review*	☐	☒	Not in a non-attainment area	N/A	N/A
Regulation 61-62.5, Standard No. 8 Toxic Air Pollutants	☐	☒	Exempt per section D.(1) and D.(2) since sources are HON MACT affected sources	N/A	N/A
Regulation 61-62.6 Control of Fugitive Particulate Matter	☐	☒	No fugitive PM sources	N/A	N/A
Regulation 61-62.68 Chemical Accident Prevention Provisions	☐	☒	No RMP chemicals stored in quantities above threshold	N/A	N/A
Regulation 61-62.70 Title V Operating Permit Program	☒	☐	Title V modification will be submitted upon startup	N/A	N/A
40 CFR Part 64 - Compliance Assurance Monitoring (CAM)	☐	☒	No changes to emission control devices	N/A	N/A
40 CFR 60 Subpart A - General Provisions	☒	☐	#1 Ox Subject to III, NNN, VV, & VVa; no change in applicability or limits	No Change	No Change
III	☒	☐	Sources in #1OX subject, no change in applicability or limts	No Chnage	No Change
NNN	☒	☐	Sources in #1OX subject, no change in applicability or limts	No Change	No Chnage

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STATE AND FEDERAL AIR POLLUTION CONTROL REGULATIONS AND STANDARDS *(If not listed below add any additional regulations that are triggered.)*					
	Applicable		**Include all limits, work practices, monitoring, record keeping, etc.**		
Regulation	**Yes**	**No**	**Explain Applicability Determination**	**List the specific limitations and/or requirements that apply.**	**How will compliance be demonstrated?**
VV	☒	☐	Sources in #1OX subject, no change in applicability or limts	No Change	No Change
VVa	☒	☐	Sources in #1OX subject, no change in applicability or limts	No Change	No Change
40 CFR 61 Subpart A - General Provisions	☒	☐	#1 Ox Subject to FF, no change in applicability of limits.	No Change	No Change
FF	☒	☐	Facility is below control requirements based on TAB	No Change	No Change
40 CFR 63 Subpart A - General Provisions	☒	☐	#1 Ox Subject to F, G, & H no change in applicability or limits	No Change	No Change
F, G, H (HON)	☒	☐	Sources in #1OX subject, no change in applicability or limts	No Change	No Change
	☐	☐			

* Green House Gas emissions must be quantified if these regulations are triggered.

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A. APPLICATION IDENTIFICATION	
1. Facility Name: BP Amoco Chemical Company - Cooper River Plant	
2. SC Air Permit Number (if known; 8-digits only): 0420 - 0029	3. Application Date: December 8, 2017
4. Project Description: Change in the method of operation of #1 Ox unit to reduce operating costs by changing the routing of overhead condensers #2 and #3. See permit application Section 2 for more details.	

B. FACILITY INFORMATION	
1. Is your company a Small Business? ☐ Yes ☒ No	2. If a Small Business or small government facility, is Bureau assistance being requested? ☐ Yes ☐ No
3. Are other facilities collocated for air compliance? ☐ Yes ☒ No	4. If Yes, provide permit numbers of collocated facilities:

C. AIR CONTACT			
Consulting Firm Name (if applicable): TRC Environmental			
Title/Position: Office Practice Leader	Salutation: Mr.	First Name: Robert	Last Name: vandenMeiracker
Mailing Address: 50 International Drive, Suite 150, Patewood Plaza Three			
City: Greenville		State: SC	Zip Code: 29615
E-mail Address: rvandenmeiracker@trcsolutions.com		Phone No.: 864.787.5261	Cell No.: 864.787.5261

D. EMISSION POINT DISPERSION PARAMETERS
Source data requirements are based on the appropriate source classification. Each emission point is classified as a point, area, volume, or flare source. Contact the Bureau of Air Quality for clarification of data requirements. Include sources on a scaled site map. Also, a picture of area or volume sources would be helpful but is not required. A user generated document or spreadsheet may be substituted in lieu of this form provided all of the required emission point parameters are submitted in the same order, units, etc. as presented in these tables.
Abbreviations / Units of Measure: UTM = Universal Transverse Mercator; °N = Degrees North; °W = Degrees West; m = meters; AGL = Above Ground Level; ft = feet; ft/s = feet per second; ° = Degrees; °F = Degrees Fahrenheit

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E. POINT SOURCE DATA

(Point sources such as stacks, chimneys, exhaust fans, and vents.)

Emission Point ID	Description/Name	Point Source Coordinates Projection:				Release Height AGL (ft)	Temp. (°F)	Exit Velocity (ft/s)	Inside Diameter (ft)	Discharge Orientation	Rain Cap? (Y/N)	Distance To Nearest Property Boundary (ft)	Building		
		UTM E (m)	UTM N (m)	Lat (°N)	Long (°W)								Height (ft)	Length (ft)	Width (ft)
O-2	#1 HPVGTS	604666.1	3649104.3			100.0	171	261.7	3.0	V	N	878	54	62	51
O-3	Low Pressure Absorber	604639	3649127			70.5	120	11.2	2.50	V	N	907	54	62	51
	No changes to other sources; see modeling analysis in Section 5 for full details of model inputs														

F. AREA SOURCE DATA

(Area sources such as storage piles, and other sources that have low level or ground level releases with no plumes.)

Emission Point ID	Description/Name	Area Source Coordinates Projection:				Release Height AGL (ft)	Easterly Length (ft)	Northerly Length (ft)	Angle From North (°)	Distance To Nearest Property Boundary (ft)
		UTM E (m)	UTM N (m)	Lat (°N)	Long (° W)					
N/A										

G. VOLUME SOURCE DATA

(Volume sources such as building fugitives that have initial dispersion vertical depth prior to release.)

Emission Point ID	Description/Name	Volume Source Coordinates Projection:				Release Height AGL (ft)	Initial Horizontal Dimension (ft)	Initial Vertical Dimension (ft)	Distance To Nearest Property Boundary (ft)
		UTM E (m)	UTM N (m)	Lat (°N)	Long (° W)				
N/A									

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H. FLARE SOURCE DATA

(Point sources where the combustion takes place at the tip of the stack.)

Emission Point ID	Description/Name	Flare Source Coordinates Projection:				Release Height AGL (ft)	Heat Release Rate (BTU/hr)	Distance To Nearest Property Boundary (ft)	Building		
		UTM E (m)	UTM N (m)	Lat (°N)	Long (° W)				Height (ft)	Length (ft)	Width (ft)
N/A											

I. AREA CIRCULAR SOURCE DATA

Emission Point ID	Description/Name	Area Circular Source Coordinates Projection:				Release Height AGL (ft)	Radius of Area (ft)	Distance To Nearest Property Boundary (ft)
		UTM E (m)	UTM N (m)	Lat (°N)	Long (° W)			
N/A								

J. AREA POLY SOURCE DATA

Emission Point ID	Description/Name	Area Poly Source Coordinates Projection:		Release Height AGL (ft)	Number of Vertices
		UTM E (m)	UTM N (m)		
N/A					

K. OPEN PIT SOURCE DATA

Emission Point ID	Description/Name	Open Pit Source Coordinates Projection:		Release Height AGL (ft)	Easterly Length (ft)	Northerly Length (ft)	Volume (ft^3)	Angle From North (°)
		UTM E (m)	UTM N (m)					
N/A								

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L. EMISSION RATES

Emission Point ID	Pollutant Name	CAS #	Emission Rate (lb/hr)	Same as Permitted [1]	Controlled or Uncontrolled	Averaging Period
O-2	CO	630-08-0	72.0	☒ Yes ☐ No	Controlled	Hourly
O-3	CO	630-08-0	14.0	☒ Yes ☐ No	No control for CO	Hourly
	No changes to other sources; see modeling analysis in Section 5 for full details of model inputs			☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		
				☐ Yes ☐ No		

(1) Any difference between the rates used for permitting and the air compliance demonstration must be explained in the application report.

Appendix B
Emission Data and Calculations

Table B-1
Project Dragonslayer PSD Emissions Analysis Summary

Post-Project PTE Emissions (tpy)

POLLUTANTS	CR #1 OX	TOTAL
CO	376.7	376.7

Baseline Actual Average 2010-2011 Emissions (tpy)

POLLUTANTS	CR #1 OX	TOTAL
CO	275.1	275.1

Step 1 - Project Pollutant Increases Above PSD Significance

POLLUTANTS	CO
TOTAL PTE	376.7
TOTAL BASELINE	275.1
DELTA	101.6
PSD SIGNIFICANCE	100
ABOVE PSD	Yes

Table B-1
Project Dragonslayer PSD Emissions Analysis Summary

Step 2 - Facility Netting

POLLUTANTS	CO
STEP 1 DELTA	101.6
TOTAL CONTEMPORANEOUS	26.9
NET EMISSIONS	128.5
PSD SIGNIFICANCE	100
ABOVE PSD	Yes

Contemporaneous Emissions

PROJECT	YEAR	CO (tpy)
502b10 - CR #1 Ox BR-301A Alternate Water Withdrawl	2008	0.0
PTA FIP Project (Permit CS)	2008	0.01
502b10 - #1 OX/PTA Op Flex	2011	0
PTA Filter Project	2012	26.9
Total	---	26.9

Table B-2
CR #1 OX PSD Analysis

PTE

EMISSION EQUIPMENT DESCRIPTION	EQUIPMENT ID NUMBER	MAXIMUM FIRE RATE (HP)	POLLUTANT EMITTED	POLLUTANT EMISSION FACTOR	UNITS	EMISSION FACTOR REFERENCE	HOURLY EMISSIONS (lb/hr)	PERMITTED OPERATING (hpy)	ANNUAL EMISSIONS (tpy)	COMMENTS
Emergency Generator #2	BM-1201	762	CO	0.00077	lb/hp-hr	Manufacturer Data	0.59	100	0.03	Diesel Fuel Sulfur = 15
Emergency Generator #4	BM-1204	737	CO	0.00077	lb/hp-hr	Manufacturer Data	0.57	100	0.03	Diesel Fuel Sulfur = 15

EMISSION EQUIPMENT DESCRIPTION	EQUIPMENT ID NUMBER	MAXIMUM RATE (lb/hr)	POLLUTANT EMITTED	POLLUTANT EMISSION FACTOR	UNITS	EMISSION FACTOR REFERENCE	HOURLY EMISSIONS (lb/hr)	PERMITTED OPERATING (hpy)	ANNUAL EMISSIONS (tpy)	COMMENTS
HPVGTS	HPVGTS-1	1758	CO*	95.9	% Removal	BP design Calcs	72.0	8,760	315.3	Maximum rate based on BP design calculations. See emission footnote
Low Pressure Absorber	BT-603	14.0	CO*			BP design Calcs	14.0	8,760	61.3	Maximum rate based on BP design calculations. See emission footnote
DHT Ovhd Scrubber	BT-702	Vent Removed	CO							**Vent Removed**

*** Emission Revision Comments**

HPVGTS - VOC	The % removal efficiency in this application was revised from the efficiency used in past construction applications. This application uses the true potential efficiency.
HPVGTS - CO	The % removal efficiency in this application was revised from the efficiency used in past construction applications. This application uses the true potential efficiency.
LPA - VOC & CO	The hourly emissions rates are revised based on the new flow scheme after the project and improvements to the LPA
Silo - PM	The emission rate has been revised based on changing to high density conveying

2010 Actuals

EMISSION EQUIPMENT DESCRIPTION	same	MAXIMUM FIRE RATE (HP)	POLLUTANT EMITTED	POLLUTANT EMISSION FACTOR	UNITS	EMISSION FACTOR REFERENCE	HOURLY EMISSIONS (lb/hr)	ACTUAL OPERATING (hpy)	ANNUAL EMISSIONS (tpy)	COMMENTS
Emergency Generator #2	BM-1201	335	CO	0.00668	lb/hp-hr	AP-42 3.3 (10/96)	2.238	33	0.04	Diesel Fuel Sulfur = 0.05%

EMISSION EQUIPMENT DESCRIPTION	EQUIPMENT ID NUMBER	MAXIMUM RATE (lb/hr)	POLLUTANT EMITTED	POLLUTANT EMISSION FACTOR	UNITS	EMISSION FACTOR REFERENCE	HOURLY EMISSIONS (lb/hr)	ACTUAL OPERATING (hpy)	ANNUAL EMISSIONS (tpy)	COMMENTS
HPVGTS	HPVGTS-1		CO			Emission Inventory	77	8,291	319.8	
Low Pressure Absorber	BT-603		CO			Emission Inventory	1	8,291	3.9	
DHT Ovhd Scrubber	BT-702		CO			Emission Inventory	76.5	62	2.4	Based on hours vent open

2011 Actuals

EMISSION EQUIPMENT DESCRIPTION	EQUIPMENT ID NUMBER	MAXIMUM FIRE RATE (HP)	POLLUTANT EMITTED	POLLUTANT EMISSION FACTOR	UNITS	EMISSION FACTOR REFERENCE	HOURLY EMISSIONS (lb/hr)	ACTUAL OPERATING (hpy)	ANNUAL EMISSIONS (tpy)	COMMENTS
Emergency Generator #2	BM-1201	335	CO	0.00668	lb/hp-hr	AP-42 3.3 (10/96)	2.238	44	0.05	Diesel Fuel Sulfur = 0.05%

EMISSION EQUIPMENT DESCRIPTION	EQUIPMENT ID NUMBER	MAXIMUM RATE (lb/hr)	POLLUTANT EMITTED	POLLUTANT EMISSION FACTOR	UNITS	EMISSION FACTOR REFERENCE	HOURLY EMISSIONS (lb/hr)	ACTUAL OPERATING (hpy)	ANNUAL EMISSIONS (tpy)	COMMENTS
HPVGTS	HPVGTS-1		CO			Emission Inventory	58	7,608	219.9	
Low Pressure Absorber	BT-603		CO			Emission Inventory	1	7,608	2.7	
DHT Ovhd Scrubber	BT-702		CO			Emission Inventory	54.7	59	1.6	Based on hours vent open

TOTAL EMISSIONS - #1 OX PTE (tpy)				
POLLUTANT	PROCESS SOURCES	COMBUSTION SOURCES	FUGITIVE SOURCES	TOTALS
CO	376.6	0.1	N/A	376.7

TOTAL EMISSIONS - #1 OX BASELINE ACTUAL (tpy)				
POLLUTANT	PROCESS SOURCES	COMBUSTION SOURCES	FUGITIVE SOURCES	TOTALS
CO	275.1	0.04	N/A	275.1

POLLUTANT	THRESHOLD	DELTA (PTE - ACTUAL)
CO	100	**101.59**

Discussion of Basis for CO Emissions from the LPA, BT-603

Based on the construction permit 0420-0029-CU the low pressure absorber, BT-603, was permitted for 4.1 lb/hr of CO emissions. The emissions testing conducted on July 28, 2017, determined the actual CO emissions were 3.4 lb/hr. BP is requesting the emissions limit be increased to 14 lb/hr of CO.

As stated in the Project description, this project proposes to remove solvent/water mixtures from all three overhead condensers to the DHT, BT-702, and BT603 which is routed to the atmosphere. Currently this mixture is only withdrawn from the 2nd and 3rd overhead condensers. The mixture from all three overhead condensers contains both dissolved and entrained CO gas. Based on process data and process simulation software (ASPEN), the amount of additional CO that could be sent to BT-603 is the 10 lb/hr difference between the current limit and the requested limit. Table B-3 summarizes the change.

To achieve the economic benefits stated in section 1.2 Purpose and Scope, the amount withdrawn from the 1st condenser will represent approximately 50 to 60% of the total. This stream runs hotter and therefore has more dissolved CO in the stream. The dissolved CO adds approximately 0.5 lb CO/hr to the BT-603 vent as it gets stripped out of the liquid phase in the DHT. This stream also has entrained gas bubbles. Based on the online measurement of CO in the reactor overhead, these gas bubbles contain 0.4 to 0.5 volume % CO. The entrained gas bubbles can add up to 8 lb CO/hr to the BT603 effluent.

The 1st condenser flow was sampled to determine the amount of gas bubble entrainment. The measurement showed approximately 250 to 350 scfm of gas entrainment in the 1st Condenser stream or about 8 lb/hr of CO.

This estimate gives an additional CO emission rate of approximately 8 lb CO/hr from BT-603. Therefore an increase in the permit limit from 4.1 to 14 lb/hr CO for this project is requested, as it includes an engineering factor for variability in the operation during startups and shutdowns, and for uncertainty in the estimate.

Table B-3
Summary of CO Emissions Change for BT603

DESCRIPTION	AMOUNT	UNIT OF MEASURE
Permit	4.1	lb CO/hr
Measured	3.4	lb CO/hr
Additional Soluble CO (from ASPEN)	0.5	lb CO/hr
1st Condenser Entrained Gas	350	scfm
Entrained CO	8.0	lb CO/hr
Total Additional CO	8.5	lb CO/hr
Safety Factor on additional CO	20%	--
Total Additional CO emissions	10.2	lb CO/hr
Sum of previous permit limit and additional CO emissions from project	14.3	lb CO/hr
Permit Application Request	14	lb CO/hr

December 6, 2017
John Childs

Appendix C
RBLC Search Results

PROCESS TYPE	RBLC ID	PROCESS	CO EMISSIONS LIMIT	CONTROL METHOD
64.003	ID-0017	Selexol Vent	8.7 lb/hr	Catox
	TX-0481	Rectisol Vent	11.4 lb/hr	NONE
		MSS Vent	21.64 lb/hr	NONE
	OH-0284	RTO Emissions	7.56 lb/hr	NONE
		TO Emissions	8.24 lb/hr	NONE
	TX-0354	TO Emissions- Steady State	9.56 lb/hr	NONE
64.999	TX-0609	Olefins Unit	146.43 tpy	Proper excess air and stream flow
	TX-0354	Incinerator	1.39 lb/hr	NONE
	TX-0675	N-10, Catalyst Regeneration	0	Good combustion practices
		N-11, Reactor Regeneration	0	Good combustion practices
		N-18, Decoking Drum	3360 lb	Good combustion practices
	TX-0624	Olefins Cracking	2256 tpy	Good engineering/combustion practices

Appendix D
BACT Analysis Cost Information

BP Cooper River
COMMON COST VALUES FOR BACT ANALYSIS

COST DESCRIPTION	COST	BASIS FOR COST
Operations and Maintenance Labor	45 $/hr	BP CR With Benefits
Natural Gas Cost	3.44 $/1,000 cf	BP CR
Electricity Cost	0.058 $/kW-hr	BP CR
Potable Water	2.67 $/1,000 gal	BP CR
Steam	5.80 $/1000 lb	BP CR
Nitrogen	1.625 $/1000 SCF	BP CR
Caustic	0.31 $/lb	BP CR
Capital Recovery Factor (8% and 20 year life)	0.10185	USEPA Financial References
Site Preparation	150,000	
Facilities and Buildings	25,000	

LPA CO COST TABLES
LPA DIRECT FIRE THERMAL OXIDIZER
BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs:			
Direct Fired Thermal Oxidizer (Input Cost: QAQPS USEPA Factor)		$255,000	
Ancillary Equipment		$38,250	N/A
Blower		$30,000	
Ancillary Equipment		$4,500	
		Sum = "A" =	*$327,750*
Instrumentation (0.10 * A)		$32,775	
Sales Taxes (0.03 * A)		$9,833	
Freight (0.05 * A)		$16,388	
	Purchased Equipment Cost = "B" =		*$386,745*
Direest Installation Costs			
Foundation and Supports (0.08 * B)		$30,940	
Handling and Errection (0.14 * B)		$54,144	
Electrical (0.04 * B)		$15,470	
Piping, Ductwork, and Installation (0.02 *B)		$7,735	
Insulation for Ductwork (0.01 * B)		$3,867	
Painting (0.01 * B)		$3,867	
	Direct Installation Cost =		*$116,024*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$677,769*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$38,675	
Construction and Field Expenses (0.05 *B)		$19,337	
Contractor Fees (0.10 *B)		$38,675	
Start-Up (0.02 *B)		$7,735	
Performance Test (0.01 *B)		$3,867	
Contingencies (0.03 * B)		$11,602	
	Total Indirect Cost =		*$119,891*
	TOTAL CAPITAL INVESTMENT =		**$797,659**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$32,850
Supervisor	= (15% of Operator Cost)		$4,928
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$5,475
Maintenance Materials	= 100% of Maintenance Labor		$5,475
Replacement Labor	N/A		$0
Parts Cost	N/A		$0
Utilities:			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	165.0	$298,331
Electricity	= $/kWhr*hp*1 kWhr/1.341 hp*8760 hr/yr	40.5	$15,345
		Total DC =	*$362,403*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$48,728	$29,237
Administrative	= 2% of Total Capital Investment		$15,953
Property Tax	= 1% of Total Capital Investment		$7,977
Insurance	= 1% of Total Capital Investment		$7,977
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$81,242
		Total IC =	*$142,384*
	TOTAL ANNUAL OPERATING COSTS =		**$504,787**

LPA CATALYTIC THERMAL OXIDIZER (New)

BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs:			
Catalytic Thermal Oxidizer (User Input Cost: QAQPS USEPA Factor)		$ 417,000	
Ancillary Equipment		$62,550	N/A
Blower		$30,000	
Ancillary Equipment		$4,500	
		Sum = "A" =	*$ 514,050.00*
Instrumentation (0.10 * A)		$51,405	
Sales Taxes (0.03 * A)		$15,422	
Freight (0.05 * A)		$25,703	
	Purchased Equipment Cost = "B" =		*$606,579*
Direst Installation Costs			
Foundation and Supports (0.08 * B)		$48,526	
Handling and Errection (0.14 * B)		$84,921	
Electrical (0.04 * B)		$24,263	
Piping, Ductwork, and Installation (0.02 *B)		$12,132	
Insulation for Ductwork (0.01 * B)		$6,066	
Painting (0.01 * B)		$6,066	
	Direct Installation Cost =		*$181,974*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$963,553*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$60,658	
Construction and Field Expenses (0.05 *B)		$30,329	
Contractor Fees (0.10 *B)		$60,658	
Start-Up (0.02 *B)		$12,132	
Performance Test (0.01 *B)		$6,066	
Contingencies (0.03 * B)		$18,197	
	Total Indirect Cost =		*$188,039*
	TOTAL CAPITAL INVESTMENT =		**$1,151,592**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$14,600
Supervisor	= (15% of Operator Cost)		$2,190
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$14,600
Maintenance Materials	= 100% of Maintenance Labor		$14,600
Replacement Labor	N/A		$0
Catalyst Cost	= CF cat* $850/CF* 1@5 years	25	$4,250
Utilities:			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	45.0	$81,363
Electricity	= $/kWhr*hp*1 kWhr/1.341 hp*8760 hr/yr	40.5	$15,345
		Total DC =	*$146,948*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$45,990	$27,594
Administrative	= 2% of Total Capital Investment		$23,032
Property Tax	= 1% of Total Capital Investment		$11,516
Insurance	= 1% of Total Capital Investment		$11,516
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$117,290
		Total IC =	*$190,947*
	TOTAL ANNUAL OPERATING COSTS =		**$337,895**

LPA TO EXISTING CATALYTIC THERMAL OXIDIZER ON HPA

BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs: Existing Unit			
Catalytic Thermal Oxidizer (User Input Cost; QAQPS USEPA Factor)		$0	
Ancillary Equipment		$0	
Compressor		$300,000	
Ancillary Equipment		$45,000	
		Sum = "A" =	*$345,000*
Instrumentation (0.10 * A)		$34,500	
Sales Taxes (0.03 * A)		$10,350	
Freight (0.05 * A)		$17,250	
	Purchased Equipment Cost = "B" =		*$407,100*
Direst Installation Costs			
Foundation and Supports (0.08 * B)		$32,568	
Handling and Errection (0.14 * B)		$56,994	
Electrical (0.04 * B)		$16,284	
Piping, Ductwork, and Installation (0.02 *B)		$8,142	
Insulation for Ductwork (0.01 * B)		$4,071	
Painting (0.01 * B)		$4,071	
	Direct Installation Cost =		*$122,130*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$704,230*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$40,710	
Construction and Field Expenses (0.05 *B)		$20,355	
Contractor Fees (0.10 *B)		$40,710	
Start-Up (0.02 *B)		$8,142	
Performance Test (0.01 *B)		$4,071	
Contingencies (0.03 * B)		$12,213	
	Total Indirect Cost =		*$126,201*
	TOTAL CAPITAL INVESTMENT =		**$830,431**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Supervisor	= (15% of Operator Cost)		$2,464
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	3	$98,550
Maintenance Materials	= 100% of Maintenance Labor		$98,550
Replacement Labor	N/A		$0
Catalyst Cost	= CF cat* $850/CF* 1@5 years	**478**	$81,260
Utilities:			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	65.0	$117,524
Electricity	= $/kWhr*hp*1 kWhr/1.341 hp*8760 hr/yr	1341.0	$508,080
		Total DC =	*$922,853*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$215,989	$129,593
Administrative	= 2% of Total Capital Investment		$16,609
Property Tax	= 1% of Total Capital Investment		$8,304
Insurance	= 1% of Total Capital Investment		$8,304
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$84,579
		Total IC =	*$247,390*
	TOTAL ANNUAL OPERATING COSTS =		**$1,170,243**

LPA REGENERATIVE THERMAL OXIDIZER

BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs			
Regenerative Thermal Oxidizer (User Input Cost: QAQPS USEPA Factor)		$430,000	
Ancillary Equipment		$64,500	N/A
Blower		$30,000	
Ancillary Equipment		$4,500	
		Sum = "A" =	*529,000*
Instrumentation (0.10 * A)		$52,900	
Sales Taxes (0.03 * A)		$15,870	6
Freight (0.05 * A)		$26,450	
	Purchased Equipment Cost = "B" =		*$624,220*
Direst Installation Costs			
Foundation and Supports (0.08 * B)		$49,938	
Handling and Errection (0.14 * B)		$87,391	
Electrical (0.04 * B)		$24,969	
Piping, Ductwork, and Installation (0.02 *B)		$12,484	
Insulation for Ductwork (0.01 * B)		$6,242	
Painting (0.01 * B)		$6,242	
	Direct Installation Cost =		*$187,266*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$986,486*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$62,422	
Construction and Field Expenses (0.05 *B)		$31,211	
Contractor Fees (0.10 *B)		$62,422	
Start-Up (0.02 *B)		$12,484	
Performance Test (0.01 *B)		$6,242	
Contingencies (0.03 * B)		$18,727	
	Total Indirect Cost =		*$193,508*
	TOTAL CAPITAL INVESTMENT =		**$1,179,994**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Supervisor	= (15% of Operator Cost)		$2,464
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Maintenance Materials	= 100% of Maintenance Labor		$16,425
Replacement Labor	N/A		$0
Parts Cost	N/A		$0
Utilities			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	40.0	$72,323
Electricity	= $/kWhr* kWhr *8760 hr/yr	40.0	$20,323
Media Replacement	= CF media * $50/CF / 2 years	400.0	$10,000
		Total DC =	*$154,385*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$51,739	$31,043
Administrative	= 2% of Total Capital Investment		$23,600
Property Tax	= 1% of Total Capital Investment		$11,800
Insurance	= 1% of Total Capital Investment		$11,800
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$120,182
		Total IC =	*$198,425*
	TOTAL ANNUAL OPERATING COSTS =		**$352,810**

LPA RECUPERATIVE THERMAL OXIDIZER

BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs:			
Recuperative Thermal Oxidizer (User Input Cost: QAQPS USEPA Factor)		$600,000	
Ancillary Equipment		$90,000	
Blower		$30,000	
Ancillary Equipment		$4,500	
		Sum = "A" =	*$724,500*
Instrumentation (0.10 * A)		$72,450	
Sales Taxes (0.03 * A)		$21,735	
Freight (0.05 * A)		$36,225	
	Purchased Equipment Cost = "B" =		*$854,910*
Direst Installation Costs			
Foundation and Supports (0.08 * B)		$68,393	
Handling and Errection (0.14 * B)		$119,687	
Electrical (0.04 * B)		$34,196	
Piping, Ductwork, and Installation (0.02 *B)		$17,098	
Insulation for Ductwork (0.01 * B)		$8,549	
Painting (0.01 * B)		$8,549	
	Direct Installation Cost =		*$256,473*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$1,286,383*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$85,491	
Construction and Field Expenses (0.05 *B)		$42,746	
Contractor Fees (0.10 *B)		$85,491	
Start-Up (0.02 *B)		$17,098	
Performance Test (0.01 *B)		$8,549	
Contingencies (0.03 * B)		$25,647	
	Total Indirect Cost =		*$265,022*
	TOTAL CAPITAL INVESTMENT =		**$1,551,405**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Supervisor	= (15% of Operator Cost)		$2,464
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Maintenance Materials	= 100% of Maintenance Labor		$16,425
Replacement Labor	N/A		$0
Parts Cost	N/A		$0
Utilities:			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	50.0	$90,403
Electricity	= $/kWhr*hp*1 kWhr/1.341 hp*8760 hr/yr	40.0	$15,155
		Total DC =	*$157,297*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$51,739	$31,043
Administrative	= 2% of Total Capital Investment		$31,028
Property Tax	= 1% of Total Capital Investment		$15,514
Insurance	= 1% of Total Capital Investment		$15,514
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$158,011
		Total IC =	*$251,110*
	TOTAL ANNUAL OPERATING COSTS =		**$408,407**

Appendix E
Federal Land Manager Reply

From:	Fox, David
Sent:	Thursday, November 02, 2017 4:54 PM
To:	Catherine_Collins@fws.gov
Cc:	VandenMeiracker, Robert
Subject:	Notification of PSD Permit Revision
Attachments:	FLM_EMAIL.PDF

Hello Catherine

BP Amoco Chemical Company received a PSD permit for their facility located near the Cape Romain National Wildlife Refuge in 2014.

You reviewed the details of that project and prepared an e-mail response (attached) concerning the FWS's interest in the project..

The company now is proposing to redistribute some permitted emissions of carbon monoxide from the project. The proposed changes will not however result in the permitted increase in emissions on an hourly or annual basis for carbon monoxide or any other criteria pollutant. The e-mail above lists the permitted annual emissions.

Since the initial project was a PSD permitting project, it is necessary for the company to apply for a PSD permit modification with the South Carolina DHEC to redistribute the emission limits.

That in turn triggers the need to notify FLMs about the project.

We are doing that with this e-mail.

Please let me know if you have any questions or concerns concerning the permit revision.

Thanks

David Fox CCM
TRC Environmental
608-826-3622

Doerner, Michael

From: Collins, Catherine <catherine_collins@fws.gov>
Sent: Tuesday, March 12, 2013 2:44 PM
To: Doerner, Michael
Subject: Re: FW: BP Cooper River PSD Permit Application

Thank you for sending the information regarding the project near the Cape Romain National Wildlife Refuge. Based on the emission changes identified in the document and distance from the Class I area(s) listed below, the Fish and Wildlife Service anticipates that modeling would not show any significant additional impacts to air quality related values (AQRV) at the Class I area(s) administered by the FWS. Therefore, we are not requesting that a Class I AQRV analysis be included in the PSD permit application. Our screening of this analysis does not indicate agreement with any AQRV analysis protocols or conclusions applicants may make independent of Federal Land Manager review. Please note that we are specifically addressing the need for an AQRV analysis for Class I areas managed by the Fish and Wildlife Service.

Class I Area:

Cape Romain NWR

Distance to Facility in kilometers

21.6 km

Annual Emissions (based on short term maximum emission rates adjusted to an annual emission rate) in tons per year (tpy)

+ 27.4	Nitrogen Oxides
+ 0.3	Sulfur Oxides
+ 4.7	Total Fine particulate matter
+ 72.6	Volatile organic compounds
+ 439.6	Carbon Monoxide

The state and/or EPA may have a different opinion regarding the need for a Class I increment analysis. Should the emissions or the nature of the project change significantly, please contact me, so that we might re-evaluate the revised proposed project.

Thank you for keeping us informed and involving the Fish and Wildlife Service in the project review.

Catherine Collins, Environmental Engineer
U.S. Fish and Wildlife Service
Air Quality Branch
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235-2034

Appendix F
Air Modeling Information

The air modeling information is provided on the attached compact disc.

Appendix G
USEPA Control Technology Fact Sheet – Incinerators

EPA-452/F-03-022

Air Pollution Control Technology
Fact Sheet

See Bottom of page 3

Name of Technology: Thermal Incinerator

This type of incinerator is also referred to as a direct flame incinerator, thermal oxidizer, or afterburner. However, the term afterburner is generally appropriate only to describe a thermal oxidizer used to control gases coming from a process where combustion is incomplete.

Type of Technology: Destruction by thermal oxidation

Applicable Pollutants: Primarily volatile organic compounds (VOC). Some particulate matter (PM), commonly composed as soot (particles formed as a result of incomplete combustion of hydrocarbons (HC), coke, or carbon residue) will also be destroyed in various degrees.

Achievable Emission Limits/Reductions:

VOC destruction efficiency depends upon design criteria (i.e., chamber temperature, residence time, inlet VOC concentration, compound type, and degree of mixing) (EPA, 1992). Typical thermal incinerator design efficiencies range from 98 to 99.99% and above, depending on system requirements and characteristics of the contaminated stream (EPA, 1992; EPA, 1996a). The typical design conditions needed to meet 98% or greater control or a 20 parts per million by volume (ppmv) compound exit concentration are: 870°C (1600°F) combustion temperature, 0.75 second residence time, and proper mixing. For halogenated VOC streams, 1100°C (2000°F) combustion temperature, 1.0 second residence time, and use of an acid gas scrubber on the outlet is recommended (EPA, 1992).

For vent streams with VOC concentration below approximately 2000 ppmv, reaction rates decrease, maximum VOC destruction efficiency decreases, and an incinerator outlet VOC concentration of 20 ppmv, or lower may be achieved (EPA, 1992).

Controlled emissions and/or efficiency test data for PM in incinerators are not generally available in the literature. Emission factors for PM in phthalic anhydride processes with incinerators are available, however. The PM control efficiencies for these processes were found to vary from 79 to 96% (EPA, 1998). In EPA's 1990 National Inventory, incinerators used as control devices for PM were reported as achieving 25 to 99% control efficiency of particulate matter 10 microns or less in aerodynamic diameter (PM_{10}) at point source facilities (EPA, 1998). Table 1 presents a breakdown of the PM_{10} control efficiency ranges by industry for recuperative incinerators (EPA, 1996b). The VOC control efficiency reported for these devices ranged from 0 to 99.9%. These ranges of control efficiencies are large because they include facilities that do not have VOC emissions and control only PM, as well as facilities which have low PM emissions and are primarily concerned with controlling VOC (EPA, 1998).

Table 1. Thermal Incinerator PM_{10} Destruction Efficiencies by Industry (EPA, 1996b)

Industry/Types of Sources	PM_{10} Control Efficiency (%)
Petroleum and Coal Products asphalt roofing processes (blowing, felt saturation); mineral calcining; petroleum refinery processes (asphalt blowing, catalytic cracking, coke calcining, sludge converter); sulfur manufacturing	25 - 99.9
Chemical and Allied Products carbon black manufacturing (mfg); charcoal mfg; liquid waste disposal; miscellaneous chemical mfg processes; pesticide mfg; phthalic anhydride mfg (xylene oxidation); plastics/synthetic organic fiber mfg; solid waste incineration (industrial)	50 - 99.9
Primary Metals Industries by-product coke processes (coal unloading, oven charging and pushing, quenching); gray iron cupola and other miscellaneous processes; secondary aluminum processes (burning/drying, smelting furnace); secondary copper processes (scrap drying, scrap cupola, and miscellaneous processes); steel foundry miscellaneous processes; surface coating oven	70 - 99.9
Electronic and Other Electric Equipment chemical mfg miscellaneous processes; electrical equipment bake furnace; fixed roof tank; mineral production miscellaneous processes; secondary aluminum roll/draw extruding; solid waste incineration (industrial)	70 - 99.9
Electric, Gas, and Sanitary Services internal combustion engines; solid waste incineration (industrial, commercial/ institutional)	90 - 98
Stone, Clay, and Glass Products barium processing kiln; coal cleaning thermal dryer; fabricated plastics machinery; wool fiberglass mfg	50 - 95
Food and Kindred Products charcoal processing, miscellaneous; corn processing, miscellaneous, fugitive processing, miscellaneous; soybean processing, miscellaneous	70 - 98
Mining asphalt concrete rotary dryer; organic chemical air oxidation units, sulfur production	70 - 99.6
National Security and International Affairs solid waste incineration (commercial/institutional and municipal)	70
Textile Mill Products plastics/synthetic organic fiber (miscellaneous processes)	88 - 95
Industrial Machinery and Equipment secondary aluminum processes (burning/drying, smelt furnace)	88 -98
Lumber and Wood Products solid waste incineration (industrial)	70
Transportation Equipment solid waste incineration (industrial)	70 - 95

Applicable Source Type: Point

Typical Industrial Applications:

Thermal incinerators can be used to reduce emissions from almost all VOC sources, including reactor vents, distillation vents, solvent operations, and operations performed in ovens, dryers, and kilns. They can handle minor fluctuations in flow, however, excess fluctuations require the use of a flare (EPA, 1992). Their fuel consumption is high, so thermal units are best suited for smaller process applications with moderate-to-high VOC loadings.

Incinerators are used to control VOC from a wide variety of industrial processes, including, but not limited to the following (EPA, 1992):

- Storing and loading/unloading of petroleum products and other volatile organic liquids;
- Vessel cleaning (rail tank cars and tank trucks, barges);
- Process vents in the synthetic organic chemical manufacturing industry (SOCMI);
- Paint manufacturing;
- Rubber products and polymer manufacturing;
- Plywood manufacturing;
- Surface coating operations:
  Appliances, magnetic wire, automobiles, cans, metal coils, paper, film and foil, pressure sensitive tapes and labels, magnetic tape, fabric coating and printing, metal furniture, wood furniture, flatwood paneling, aircraft, miscellaneous metal products;
- Flexible vinyl and urethane coating;
- Graphic arts industry; and
- Hazardous waste treatment storage, and disposal facilities (TSDFs).

Emission Stream Characteristics:

a. **Air Flow:** Typical gas flow rates for thermal incinerators are 0.24 to 24 standard cubic meters per second (sm^3/sec) (500 to 50,000 standard cubic feet per minute (scfm)) (EPA, 1996a).

b. **Temperature:** Most incinerators operate at higher temperatures than the ignition temperature, which is a minimum temperature. Thermal destruction of most organic compounds occurs between 590°C and 650°C (1100°F and 1200°F). Most hazardous waste incinerators are operated at 980°C to 1200°C (1800°F to 2200°F) to ensure nearly complete destruction of the organics in the waste (AWMA, 1992).

a. **Pollutant Loading:** Thermal incinerators can be used over a fairly wide range of organic vapor concentrations. For safety considerations, the concentration of the organics in the waste gas must be substantially below the lower flammable level (lower explosive limit, or LEL) of the specific compound being controlled. As a rule, a safety factor of four (i.e., 25% of the LEL) is used (EPA, 1991, AWMA, 1992). The waste gas may be diluted with ambient air, if necessary, to lower the concentration. Considering economic factors, thermal incinerators perform best at inlet concentrations of around 1500 to 3000 ppmv, because the heat of combustion of hydrocarbon gases is sufficient to sustain the high temperatures required without addition of expensive auxiliary fuel (EPA, 1995).

d. **Other Considerations:** Incinerators are not generally recommended for controlling gases containing halogen- or sulfur-containing compounds, because of the formation of hydrogen chloride, hydrogen fluoride gas, sulfur dioxide, and other highly corrosive acid gases. It may be necessary to install a post-oxidation acid gas treatment system in such cases, depending on the outlet concentration. This would likely make incineration an uneconomical option. (EPA, 1996a). Thermal incinerators are also not generally cost-effective for low-concentration, high-flow organic vapor streams (EPA, 1995).

Emission Stream Pretreatment Requirements:

Typically, no pretreatment is required, however, in some cases, a concentrator (e.g., carbon or zeolite adsorption) may be used to reduce the total gas volume to be treated by the more expensive incinerator.

Cost Information:

The following are cost ranges (expressed in 2002 dollars) for packaged thermal incinerators 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. The costs do not include costs for a post-oxidation acid gas treatment system. Costs can be substantially higher than in the ranges shown when used for low to moderate VOC concentration streams (less than around 1000 to 1500 ppmv). 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. Operating and Maintenance (O & M) Costs, Annualized Cost, and Cost Effectiveness are dominated by the cost of supplemental fuel required.

a. **Capital Cost:** \$53,000 to \$190,000 per sm^3/sec (\$25 to \$90 per scfm)

b. **O & M Cost:** \$11,000 to \$160,000 per sm^3/sec (\$5 to \$75 per scfm), annually

c. **Annualized Cost:** \$17,000 to \$208,000 per sm^3/sec (\$8 to \$98 per scfm), annually

d. **Cost Effectiveness:** \$440 to \$3,600 per metric ton (\$400 to \$3,300 per short ton), annualized cost per ton per year of pollutant controlled

Theory of Operation:

Incineration, or thermal oxidation is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to carbon dioxide and water. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process. These factors provide the basic design parameters for VOC oxidation systems (ICAC, 1999).

A straight thermal incinerator is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger (this type of incinerator is referred to as a recuperative incinerator).

The heart of the thermal incinerator is a nozzle-stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. Upon passing through the flame, the waste gas is heated from its preheated inlet temperature to its ignition temperature. The ignition temperature varies for different compounds and is usually determined empirically. It is the temperature at which the combustion reaction rate exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value. Thus, any organic/air mixture will ignite if its temperature is raised to a sufficiently high level (EPA, 1996a).

The required level of VOC control of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. The nominal residence time of the reacting waste gas in the combustion chamber is defined as the combustion chamber volume divided by the volumetric flow rate of the gas. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 650 to 1100°C (1200 to 2000°F). Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control (EPA, 1996a).

Studies based on actual field test data, show that commercial incinerators should generally be run at 870°C (1600°F) with a nominal residence time of 0.75 seconds to ensure 98% destruction of non-halogenated organics (EPA, 1992).

Advantages:

Incinerators are one of the most positive and proven methods for destroying VOC, with efficiencies up to 99.9999% possible. Thermal incinerators are often the best choice when high efficiencies are needed and the waste gas is above 20% of the LEL.

Disadvantages:

Thermal incinerator operating costs are relatively high due to supplemental fuel costs.

Thermal incinerators are not well suited to streams with highly variable flow because of the reduced residence time and poor mixing during increased flow conditions which decreases the completeness of combustion. This causes the combustion chamber temperature to fall, thus decreasing the destruction efficiency (EPA, 1991).

Incinerators, in general, are not recommended for controlling gases containing halogen- or sulfur-containing compounds because of the formation of highly corrosive acid gases. It may be necessary to install a post-oxidation acid gas treatment system in such cases, depending on the outlet concentration (EPA, 1996a). Thermal incinerators are also not generally cost-effective for low-concentration, high-flow organic vapor streams (EPA, 1995).

Other Considerations:

Thermal incinerators are not usually as economical, on an annualized basis, as recuperative or regenerative incinerators because they do not recover waste heat energy from the exhaust gases. This heat can be used to preheat incoming air, thus reducing the amount of supplemental fuel required. If there is additional heat energy available, it can be used for other process heating needs.

References:

AWMA, 1992. Air & Waste Management Association, Air Pollution Engineering Manual. Van Nostrand Reinhold, New York.

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EPA, 1992. U.S. EPA, Office of Air Quality Planning and Standards, "Control Techniques for Volatile Organic Emissions from Stationary Sources," EPA-453/R-92-018, Research Triangle Park, NC., December.

EPA, 1995. U.S. EPA, Office of Air Quality Planning and Standards, "Survey of Control Technologies for Low Concentration Organic Vapor Gas Streams," EPA-456/R-95-003, Research Triangle Park, NC., May.

EPA, 1996a. U.S. EPA, Office of Air Quality Planning and Standards, "OAQPS Control Cost Manual," Fifth Edition, EPA 453/B-96-001, Research Triangle Park, NC. February.

EPA, 1996b. U.S. EPA, "1990 National Inventory," Research Triangle Park, NC, January.

EPA, 1998. U.S. EPA, Office of Air Quality Planning and Standards, "Stationary Source Control Techniques Document for Fine Particulate Matter," EPA-452/R-97-001, Research Triangle Park, NC, October.

ICAC, 1999. Institute of Clean Air Companies internet web page www.icac.com, Control Technology Information - Thermal Oxidation, page accessed March 1999.

Appendix D

Draft Construction Permit No. 0420-0029-CU

S.C. Department of Health and
Environmental Control

Bureau of Air Quality
PSD Construction Permit

BP Amoco Chemical Company-Cooper River Plant
1306 Amoco Drive
Wando, SC 29492
Berkeley County

In accordance with the provisions of the Pollution Control Act, Sections 48-1-50(5), 48-1-100(A), and 48-1-110(a), the 1976 Code of Laws of South Carolina, as amended, and South Carolina Regulation 61-62, Air Pollution Control Regulations and Standards, the Bureau of Air Quality authorizes the construction of this facility and the equipment specified herein in accordance with the plans, specifications, and other information submitted in the construction permit application received on April 11, 2013, as amended. All official correspondence, plans, permit applications, and written statements are an integral part of the permit. Any false information or misrepresentation in the application for a construction permit may be grounds for permit revocation.

The construction and subsequent operation of this facility is subject to and conditioned upon the terms, limitations, standards, and schedules contained herein or as specified by this permit and its accompanying attachments.

Permit Number: **0420-0029-CU**
Issue Date: **DRAFT**

Steve McCaslin, P. E., Director
Air Permitting Division
Bureau of Air Quality

RECORD OF REVISIONS	
Date	**Description of Changes**
	Updated project description, increased BACT limit for #1 OX Low Pressure Absorber (ID BT-603), decreased BACT limit for #1 OX High Pressure Absorber (ID BT-401), and general template updates.

A. PROJECT DESCRIPTION

Permission is hereby granted to modify the #1 and #2 Oxidation (OX) Units to remove limitations that prevent the units from operating at their design capacities (debottlenecking); and to make minor modifications to the #1 and #2 Purified Terephthalic Acid (PTA) Units to reduce operating costs. In general, these modifications will include improvements to the reaction environment, additional reaction air capacity, optimization of the recovery systems, improved Dehydration Tower (DHT) operation, improved energy recovery, removal of several emission points, addition of dense phase conveying and additional cooling tower capacity. These changes will result in increased actual hourly production and emissions rates, but will not increase maximum production rates or potential emission rates. This project is referred to as the OX Modernization/Debottleneck project.

The specific equipment revisions, additions, and removals included in the proposed project are as follows:

1. #1 OX unit
    - Replacement of the four existing reactors (BR-301 A-D) with a new single more efficient reactor (BR-301)
    - Replacement of the reactor overhead condenser system
    - Replacement of the air compressor rotor to reduce energy consumption
    - Direct injection of Paraxylene (PX) to the new reactor
    - Additional reactor overhead recovery capacity by replacing equipment with an improved design
    - Routing of 1st crystallizer (BD-401) vent to reactor off-gas recovery system
    - Maintain power recovery in off-gas expander by lowering upstream pressure drop
    - Conversion of dehydration tower (DHT) to azeotropic distillation unit
    - Change DHT overhead recovery system to a two-stage system by:
        - Converting existing DHT Scrubber (BT-702) to a one-stage acid scrubber
        - Routing the DHT Scrubber vent to the Low Pressure Absorber (LPA) (BT-603)
        - Revising the packing in the LPA
    - Change High Pressure Absorber (T-401) internal packing
    - Addition of dense phase conveying (conveyance of solids with less carrier gas)
    - Additional capacity for filters
    - Removal of the low pressure vent gas treatment (LPVGT) compressor (BC-710)
    - Removal of the solvent stripper (BT-605)
    - Removal of the residue evaporator (BM-606) and catalyst recovery unit (BD-625/631/632/BE-645)
    - Removal of the PX Stripper (BT-740)
    - Addition of a steam turbine to generate power from excess low pressure steam
    - Addition of a fixed roof NBA storage tank,
    - New replacement of existing Emergency Generator (BM-1201)
    - Addition of a new Emergency Generator (BM-1204)
    - Withdraw solvent/water mixture from reactor overhead condenser #1

2. #1 PTA unit
    - Revisions to crystallizer vent scrubber (CM-301) to improve energy recovery
    - Addition of a 5th crystallizer (CD-300)
    - Addition of dense phase conveying
    - Replacement of dryer (CM-403B)

A. PROJECT DESCRIPTION

3. #2 OX unit
    - Direct injection of PX to reactor
    - Re-rating (Modification) of air compressor for additional capacity
    - Replacement of reactor overhead condenser
    - Conversion of dehydration tower (DHT) (DT-403) to an azeotropic distillation unit
    - Modification of packing or trays in DHT (DT-403), High Pressure Absorber (HPA) (DT-111), LPA (DT-302), Dryer Scrubber (DT-301) and High Pressure Vent Gas Treatment System (HPVGTS) Scrubber (DT-1821)
    - Routing of DHT (DT-403) vent to LPA system (DT-302)
    - Addition of dense phase conveying
    - Removal of Low Pressure Vent Gas Treatment (LPVGT) System compressor (DC-304)
    - Removal of solvent stripper (DT-402) system
    - Removal of the residue evaporator (DM-403) and catalyst recovery unit (DD-412/413/414/DE-416)
    - Removal of PX Stripper (DT-404)
    - Addition of a steam turbine to generate power from excess steam
    - Addition of a fixed roof NBA storage tank,

4. #2 PTA Unit
    - Modifications to crystallizer vent scrubber (DM-601) to improve energy recovery
    - Modification of piping system from PTA Feed Drum (DD-500) to the Sundyne pumps
    - Addition of a 4th Sundyne pump
    - Addition of dense phase conveying
    - Replacement of dryer (DM-703)

5. Cooling Towers
    - Additional #1 Cooling Tower capacity
    - Additional #2 Cooling Tower capacity

The project will also include smaller items that will occur on all the units in the following general categories:

1. Additional and/or improved automation, multivariable control schemes, and on-line analyzers to increase unit reliability and improve process control.
2. Replacement of process equipment and piping that are negatively impacting maintenance costs and unit reliability.
3. Replacement of obsolete or end-of-life equipment such as piping, instruments, and computer equipment, where replacement parts are no longer available and equipment that has been determined to be too worn or corroded.
4. Replacement of exchangers and vessels to improve metallurgy, reduce corrosion, and reduce maintenance costs.

As part of this project, BP Amoco – Cooper River Plant (BPCR) is removing synthetic minor PSD avoidance limits that were established in construction permits 0560-0029-CF, -CJ, -CP, and -CR for the following emission points: #1 OX

A. PROJECT DESCRIPTION

DHT Scrubber, #1 and #2 OX LPA's, #1 and #2 OX HPVGTS, #2 PTA Crystallizer Vent Scrubber, #2 OX HPVGTS Heater, and the combined limit for CR#1 and CR#2 Plants. The table below lists the individual synthetic minor limits that will be removed. These emission points have been included in the BACT analysis.

Synthetic Minor Limits To Be Removed						
OP ID	**CP ID(s)**	**Process/Equipment (Equipment ID)**	**Pollutant**	**Emission Limitation (lb/hr)**	**Emission Limitation (TPY)**	**Proposed BACT Limit (lb/hr)**
03	CP & CR	#1 OX LPA (BT-603)	VOC	40	80	9.6
03	CR	#1 OX LPA (BT-603)	CO	N/A	40	14.0
03	CP & CR	#1 OX DHT Scrubber (BT-702)	VOC	60	165	N/A(1)
03	CR	#1 OX DHT Scrubber (BT-702)	CO	N/A	380	
03	CJ & CR	#1 OX HPVGTS (HPA (BT-401))	VOC	85	80	4.7
03	CJ & CR	#1 OX HPVGTS (HPA (BT-401))	CO	1452	375	72.0
05	CF(2)	#2 OX LPA (DT-302)	VOC	15.57	N/A	8.85
		#2 OX HPVGTS (HPA (DT-111))				3.5
05	CF(2)	#2 PTA Unit Crystallizer Vent Scrubber (DM-601)	VOC	25.6	N/A	20.0
05	CF(2)	#2 OX Fugitives	VOC	3.5	N/A	HON LDAR
05	CF(2)	#2 OX HPVGTS Fired Heater	VOC	0.84	N/A	0.0055 lb/MM BTU
03-06	CP	Combined total for CR#1 & CR#2	VOC	N/A	1825	Replaced with individual vent limits

(1) The #1 OX DHT Scrubber will no longer vent to the atmosphere and is being routed to the #1 OX LPA. The #1 OX LPA BACT limit accounts for the #1 OX DHT Scrubber emissions.

(2) Construction Permit 0420-0029-CF established a total PSD avoidance limit of 49.26 lb VOC/hr for the Cooper River #2 Plant. This limit consisted of these four sources of emissions, and the following sources of emissions: Incremental increase from the Tank Farm (0.02 lb/hr) and Wastewater Fugitives (3.11 lb/hr), the Anaerobic Reactor (0.31 lb/hr), and the CO_2 Stripper (0.35 lb/hr). A revised PSD avoidance SM limit established through construction permit 0420-0029 will be the sum of the emissions from the Tank Farm, Wastewater Fugitives, Anaerobic Reactor, and CO_2 Stripper (3.79 lb/hr).

BPCR has submitted a revision to the PSD to change the method of operation of the #1 OX Unit. The facility has three (3) overhead condensers on its #1 OX Unit Reactor, of which the facility currently draws a solvent/water mixture from Condensers 2 and 3. This mixture is sent to the dehydration tower (DHT), equipment ID BT-701, and the low pressure absorber (LPA), equipment ID BT-603, for solvent recovery. The facility is proposing to draw from all three condensers, as this provides better solvent and catalyst recovery, and a more stable operation. This in turns provides a significant operational savings annually. The facility is also requesting to increase the CO BACT limit for #1 OX LPA (BT-603) from 4.1 lb/hr to 14 lb/hr, based on a 30-day rolling average.

In addition to the above-mentioned modification, the facility proposes to voluntarily decrease the CO BACT limit for the high pressure vent gas treatment system (HPVGTS) from 87.9 lb/hr to 72.0 lb/hr, based on a 30-day rolling

A. PROJECT DESCRIPTION

average. This change, in effect, reduces facility wide CO emissions 6 lb/hr and 26.3 tpy.

B.1 EQUIPMENT FOR #1 OXIDATION UNIT (TV PERMIT UNIT ID 03)

Equipment ID	Equipment Description	Control Device ID	Emission Point ID
BR-301	Reactor with Overhead Condensers*	#1 HPVGTS	O-2/10/15
BD-200	PX Feed Drum*	None	None
BC-906	60# Steam Generator*	None	None
BT-700	Liquid-Liquid Extraction Tower*	None	None
BF-1405	NBA Storage Tank* (Specific Tank Size TBD)	None	None
BT-750	Entrainer Recovery Tower* (ERT)	None	O-3
BM-1201	400 kW Emergency Generator*	None	O-17
BM-1204	500 kW Emergency Generator*	None	O-24
BT-701	Dehydration Tower (DHT)	None	O-3
BD-401	1st Crystallizer	None	None
BT-603	Low Pressure Absorber (LPA)	None	O-3
BC-104	Power Recovery Expander	None	O-2/10/15
BT-400	PX Scrubber	None	None
BT-401	High Pressure Absorber (HPA)	#1 HPVGTS	O-2/10/15
BD-604	Azeo Storage Drum	None	None
BD-204	Feed Mix DrumFeed Mix Drum	None	None
BD-503	Filter Vacuum Sep. Drum	None	None
BM-1101A/B	Off-Gas Dryer	None	O-2/10/15
BM-1101C/D	Off-Gas Dryer	None	O-2/10/15

* These equipment are new. All other equipment listed is being modified.

B.2 EQUIPMENT FOR #1 PURIFIED TEREPHTHALIC ACID UNIT (TV PERMIT UNIT ID 04)

Equipment ID	Equipment Description	Control Device ID	Emission Point ID
CD-300	Crystallizer	CM-301	P-2
CM-403B	Dryer	None	P-3B

B.3 EQUIPMENT FOR #2 OXIDATION UNIT (TV PERMIT UNIT ID 05)

Equipment ID	Equipment Description	Control Device ID	Emission Point ID
DT-400	Liquid-Liquid Extraction Tower*	None	None

B.3 EQUIPMENT FOR #2 OXIDATION UNIT (TV PERMIT UNIT ID 05)

Equipment ID	Equipment Description	Control Device ID	Emission Point ID
DF-460	NBA Storage Tank* (Specific Tank Size TBD)	None	None
DT-450	Entrainer Recovery Tower* (ERT)	None	O2-1
DC-906	60# Steam Generator*	None	None
DT-403	Dehydration Tower (DHT)	None	O2-1
DT-302	Low Pressure Absorber (LPA)	None	O2-1
DC-104	Power Recovery Expander	None	O2-3/4
DD-402	Azeo Storage Drum	None	None

* These equipment are new. All other equipment listed is being modified.

B.4. CONTROL DEVICES

Control Device ID	Control Device Description	Pollutant(s) Controlled
#1 HPVGTS	#1 Oxidation Unit High Pressure Vent Gas Treatment System (Catalytic Oxidizer (CTO) (BR-1814) followed by a Scrubber)	VOC, HAP, CO
#2 HPVGTS	#2 Oxidation Unit High Pressure Vent Gas Treatment System (CTO (DR-1814) followed by a Scrubber)	VOC, HAP, CO
CM-301	Venturi Scrubber; called #1 Crystallizer Vent Scrubber (CVS)	PM, PM_{10}, $PM_{2.5}$
DM-601	Venturi Scrubber; called #2 Crystallizer Vent Scrubber (CVS)	PM, PM_{10}, $PM_{2.5}$

C. LIMITATIONS, MONITORING AND REPORTING CONDITIONS

Condition Number	Conditions
C.1	**Equipment ID/Control Device ID:** All (S.C. Regulation 61-62.1, Section II.J.1.g) A copy of the Department issued construction and/or operating permit must be kept readily available at the facility at all times. The owner or operator shall maintain such operational records; make reports; install, use, and maintain monitoring equipment or methods; sample and analyze emissions or discharges in accordance with prescribed methods at locations, intervals, and procedures as the Department shall prescribe; and provide such other information as the Department reasonably may require. All records required to demonstrate compliance with the limits established under this permit shall be maintained on site for a period of at least 5 years from the date the record was generated and shall be made available to a Department representative upon request.
C.2	**Equipment ID/Control Device ID:** All The owner/operator shall inspect, calibrate, adjust, and maintain continuous monitoring systems, monitoring devices, and gauges in accordance with manufacturer's specifications or good

C. LIMITATIONS, MONITORING AND REPORTING CONDITIONS

Condition Number	Conditions
	engineering practices. The owner/operator shall maintain on file all measurements including continuous monitoring system or monitoring device performance measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required in a permanent form suitable for inspection by Department personnel.
C.3	**Equipment ID/Control Device ID:** All All gauges shall be readily accessible and easily read by operating personnel and Department personnel (i.e. on ground level or easily accessible roof level). Monitoring parameter readings (i.e., pressure drop readings, etc.) and inspection checks shall be maintained in logs (written or electronic), along with any corrective action taken when deviations occur. Each incidence of operation outside the operational ranges, including date and time, cause, and corrective action taken, shall be recorded and kept on site. Exceedance of operational range shall not be considered a violation of an emission limit of this permit, unless the exceedance is also accompanied by other information demonstrating that a violation of an emission limit has taken place. Reports of these incidences shall be submitted semiannually. If no incidences occurred during the reporting period then a letter shall be submitted to indicate such. Any alternative method for monitoring control device performance must be preapproved by the Department and shall be incorporated into the permit as set forth in S.C. Regulation 61-62.70.7.
C.4	**Equipment/Control Device ID:** BR-1814 (#1 CTO), DR-1814 (#2 CTO), BT-603 (#1 LPA), DT-302 (#2 LPA), CM-301 (#1 CVS), DM-601 (#2 CVS) For any source test required under an applicable standard or permit condition, the owner, operator, or representative shall comply with S.C. Regulation 61-62.1, Section IV - Source Tests. Unless approved otherwise by the Department, the owner, operator, or representative shall ensure that source tests are conducted while the source is operating at the maximum expected production rate or other production rate or operating parameter which would result in the highest emissions for the pollutants being tested. Some sources may have to spike fuels or raw materials to avoid being subjected to a more restrictive feed or process rate. Any source test performed at a production rate less than the rated capacity may result in permit limits on emission rates, including limits on production if necessary. The owner or operator shall comply with any limits that result from conducting a source test at less than rated capacity. A copy of the most recent Department issued source test summary letter, whether it imposes a limit or not, shall be maintained with the operating permit, for each source that is required to conduct a source test. Site-specific test plans and amendments, notifications, and source test reports shall be submitted to the Manager of the Source Evaluation Section, Bureau of Air Quality.

C. LIMITATIONS, MONITORING AND REPORTING CONDITIONS

<table>
<tr><th>Condition Number</th><th>Conditions</th></tr>
<tr><td>C.5</td><td>Equipment/Control Device ID: BR-1814 (#1 CTO), DR-1814 (#2 CTO)

(S.C. Regulation 61-62.5, Standard No. 3, Section IX) This equipment shall be limited to the maximum allowable emissions of PM of 0.5lb/10^6 Btu and an opacity of 20%, each.

The owner/operator shall perform a visual inspection on a weekly basis. Visual inspection means a qualitative observation of opacity during daylight hours where the inspector records results in a log, noting color, duration, density (heavy or light), cause and correction action taken for any abnormal emissions. The observer does not need to be certified to conduct valid visual inspections. However, at a minimum, the observer should be trained and knowledgeable about the effects on visibility of emissions caused by background contrast, ambient lighting, and observer position relative to lighting, wind, and the presence of uncombined water. Logs shall be kept to record all visual inspections, including cause and corrective action taken for any abnormal emissions and visual inspections from date of recording. The owner/operator shall submit semiannual reports. The report shall include records of abnormal emissions, if any, and corrective actions taken.</td></tr>
<tr><td>C.6</td><td>Equipment/Control Device ID: All

(S.C. Regulation 61-62.5, Standard No. 4, Section VIII) Particulate matter emissions shall be limited to the rate specified by use of the following equations:
For process weight rates less than or equal to 30 tons per hour
$E = (F)\ 4.10P^{0.67}$ and
For process weight rates greater than 30 tons per hour
$E = (F)\ 55.0P^{0.11} – 40$
Where E = the allowable emission rate in pounds per hour
P = process weight rate in tons per hour
F = effect factor from Table B in S.C. Regulation 61-62.5, Standard No. 4

For the purposes of compliance with this condition, the process boundaries are defined as follows:
<table><tr><th>Unit IDs</th><th>Process Weight Rate (ton/hr)</th></tr><tr><td>03-04, combined</td><td>158.93</td></tr><tr><td>05-06, combined</td><td>126.57</td></tr></table>
The owner/operator shall continue to operate and maintain pressure drop gauge(s) on each module of the baghouse. Pressure drop readings shall be recorded daily during source operation. Operation and maintenance checks shall be made on at least a weekly basis for baghouse cleaning systems, dust collection hoppers, and conveying systems for proper operation. The baghouse shall be in place and operational whenever processes controlled by it are running, except during periods of baghouse malfunction or mechanical failure.</td></tr>
</table>

C. LIMITATIONS, MONITORING AND REPORTING CONDITIONS

Condition Number	Conditions
	Operational ranges for the monitored parameters shall be reviewed and re-established (if appropriate) to ensure proper operation of the pollution control equipment. These operational ranges for the monitored parameters shall be derived from stack test data, vendor certification, and/or operational history and visual inspections, which demonstrate the proper operation of the equipment. If ranges need to be re-established, these ranges and supporting documentation (certification from manufacturer, stack test results, 30 days of normal readings, opacity readings, etc.) shall be submitted to the Director of Engineering Services within 180 days of startup.
C.7	**Equipment/Control Device ID:** Unit ID 03 (#1 OX Unit), Unit ID 04 (#1 PTA Unit), Unit ID 05 (#2 OX Unit). Unit ID 06 (#1 PTA Unit) (S.C. Regulation 61-62.5, Standard No. 4, Section IX) Where construction or modification began after December 31, 1985, emissions from these source(s) (including fugitive emissions) shall not exhibit an opacity greater than 20%, each. The owner/operator shall perform a visual inspection on a weekly basis. Visual inspection means a qualitative observation of opacity during daylight hours where the inspector records results in a log, noting color, duration, density (heavy or light), cause and correction action taken for any abnormal emissions. The observer does not need to be certified to conduct valid visual inspections. However, at a minimum, the observer should be trained and knowledgeable about the effects on visibility of emissions caused by background contrast, ambient lighting, and observer position relative to lighting, wind, and the presence of uncombined water. Logs shall be kept to record all visual inspections, including cause and corrective action taken for any abnormal emissions and visual inspections from date of recording. The owner/operator shall submit semiannual reports. The report shall include records of abnormal emissions, if any, and corrective actions taken.
C.8	**Equipment/Control Device ID:** BR-1814 (#1 CTO), DR-1814 (#2 CTO) **Limits/Standards:** In accordance with Standard No. 7 – Prevention of Significant Deterioration and based on BACT analysis, BR-1814 shall be limited to 4.70 lb/hr and DR-1814 shall be limited to 3.50 lb/hr of VOC emissions, each, based on a 3-hour block average. In accordance with Standard No. 7 – Prevention of Significant Deterioration and based on BACT analysis, BR-1814 shall be limited to 72.0 lb/hr and DR-1814 shall be limited to 75.0 lb/hr of CO emissions, each, based on a 30-day rolling average. **Testing:** An initial source test for VOC and CO emissions, for each CTO, shall be conducted within 180 days after startup, and every three years thereafter. If the catalyst is replaced in a CTO, a new source test schedule shall be required as follows: A source test for VOC and CO emissions shall be conducted within 90 days after changing the catalyst in a CTO, and every three years thereafter. The source test shall be used to show compliance with the Standard No. 7 BACT limits, verify emissions, and verify monitoring parameters. The owner or operator shall operate the source(s) within the

C. LIMITATIONS, MONITORING AND REPORTING CONDITIONS

Condition Number	Conditions
	parameter(s) established during the most recent satisfactory source tests. A copy of the most recent Department issued source test summary letter(s) that established the parameter(s) shall be maintained with the construction permit. **Monitoring/Record Keeping/Reporting/Other:** The owner or operator shall monitor the inlet and outlet temperature of each CTO, while processes venting to the CTO are in operation. These parameters shall be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period (midnight to midnight), and shall be averaged together for a daily reading. The parameters used to demonstrate compliance shall be the daily average inlet temperature and the daily average delta temperature of the CTO. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met: ▪ The daily average for a parameter is outside the approved monitoring range. The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.
C.9	**Equipment/Control Device ID:** BT-603 (#1 LPA), DT-302 (#2 LPA) **Limits/Standards:** In accordance with Standard No. 7 – Prevention of Significant Deterioration and based on BACT analysis, BT-603 shall be limited to 9.60 lb/hr and DT-302 shall be limited to 8.85 lb/hr of VOC emissions, each, based on a 3-hour block average. In accordance with Standard No. 7 – Prevention of Significant Deterioration and based on BACT analysis, BT-603 shall be limited to 14.0 lb/hr and DT-302 shall be limited to 3.50 lb/hr of CO emissions, each, based on a 30-day rolling average. **Testing:** An initial source test for VOC and CO emissions, for each LPA, shall be conducted within 180 days after startup, and every three years thereafter. The source test shall be used to show compliance with the Standard No. 7 BACT limits, verify emissions, and verify monitoring parameters. The owner or operator shall operate the source(s) within the parameter(s) established during the most recent satisfactory source tests. A copy of the most recent Department issued source test summary letter(s) that established the parameter(s) shall be maintained with the construction permit. **Monitoring/Record Keeping/Reporting/Other:** The owner or operator shall monitor the top liquid flow rate and top temperature of each LPA, while processes venting to the LPA are in operation. These parameters shall be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period (midnight to midnight), and shall be averaged together for a daily reading. Records of hourly block averages of

C. LIMITATIONS, MONITORING AND REPORTING CONDITIONS

Condition Number	Conditions
	monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met: ▪ The daily average for a parameter is outside the approved monitoring range. ▪ The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day. The owner or operator shall calculate and maintain hourly CO emissions. Hourly CO emissions shall be calculated on a 30-day rolling average. Reports of the calculated values shall be submitted semiannually. An algorithm, including example calculations and emission factors, explaining the method used to determine emission rates shall only be included in the initial report. Subsequent submittals of the algorithm are required within 30 days of the change if the algorithm or basis for emissions is modified or the Department requests additional information.
C.10	**Equipment/Control Device ID:** CM-301 (#1 CVS), DM-601 (#2 CVS) **Limits/Standards:** In accordance with Standard No. 7 – Prevention of Significant Deterioration and based on BACT analysis, CM-301 and DM-601 are limited to 20.0 lb/hr VOC emissions, each, based on a 3-hour block average. In accordance with Standard No. 7 – Prevention of Significant Deterioration and based on BACT analysis, CM-301 shall be limited to 24.0 lb/hr and DM-601 shall be limited to 20.0 lb/hr of CO emissions, based on a 30-day rolling average. **Testing:** An initial source test for VOC and CO emissions, for each CVS, shall be conducted within 180 days after startup, and every three years thereafter. The source test shall be used to show compliance with the Standard No. 7 BACT limits and verify emissions. **Monitoring/Record Keeping/Reporting/Other:** The owner or operator shall calculate and maintain hourly VOC and CO emissions. Hourly VOC emissions shall be calculated on a 3-hour block average, and hourly CO emissions shall be calculated on a 30-day rolling average. Reports of the calculated values shall be submitted semiannually. An algorithm, including example calculations and emission factors, explaining the method used to determine emission rates shall only be included in the initial report. Subsequent submittals of the algorithm are required within 30 days of the change if the algorithm or basis for emissions is modified or the Department requests additional information.

C. LIMITATIONS, MONITORING AND REPORTING CONDITIONS

Condition Number	Conditions
C.11	**Equipment/Control Device ID:** Unit ID 03 (#1 OX Unit), Unit ID 05 (#2 OX Unit) **Limits/Standards:** In accordance with Standard No. 7 – Prevention of Significant Deterioration and based on BACT analysis, all fugitive VOC emissions from the #1 and #2 Oxidation Units shall be required to comply with the HON LDAR program (40 CFR 63 Subpart H). **Testing:** Testing shall be performed as per 40 CFR 63.180. **Monitoring/Record Keeping/Reporting/Other:** Monitoring, recordkeeping, and reporting shall be performed in accordance with 40 CFR 63.160 through 60.182. All VOCs from these processes shall be treated as Hazardous Air Pollutants (HAPs) for determining compliance.
C.12	**Equipment/Control Device ID:** DB-1813 (#2 OX HPVGTS Fired Heater) **Limits/Standards:** In accordance with Standard No. 7 – Prevention of Significant Deterioration and based on BACT analysis, the #2 OX HPVGTS Fired Heater shall be limited to 0.0055 lb/MM BTU for VOCs and 0.084 lb/MM BTU for CO, each based on a 3-hour block average. **Testing:** None required. **Monitoring/Record Keeping/Reporting/Other:** This source is permitted to burn only natural gas as fuel. The use of any other substances as fuel is prohibited without prior written approval from the Department. Natural gas fuel usage shall be monitored and recorded on a monthly basis. Records of natural gas usage shall be submitted semiannually. The owner or operator shall develop a tune-up plan and perform tune-ups on this source, once every 13 months from the date of startup. The tune-up plan shall be developed in accordance with manufacturer's specifications or with good engineering practices. Records of tune-ups shall be submitted semiannually. The tune-up plan shall only be included in the initial report. Subsequent submittals of the tune-up plan are required within 30 days of the change if the plan is modified or the Department requests additional information. The owner or operator shall implement good combustion practice(s) on this source. Good combustion practice is defined as maintaining proper air/fuel mixture in the combustion zone by holding excess oxygen between 3.5 and 12%. Percent excess oxygen shall be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period (midnight to midnight), and shall be averaged together for a daily reading. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met:

C. LIMITATIONS, MONITORING AND REPORTING CONDITIONS

Condition Number	Conditions
	▪ The daily average for a parameter is outside the approved monitoring range. The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.
C.13	**Equipment/Control Device ID:** BM-1201, BM-1204 **Limits/Standards:** In accordance with Standard No. 7 – Prevention of Significant Deterioration and based on BACT analysis, these sources shall meet Tier 3 emission standards of 40 CFR 60 Subpart IIII, shall be limited to operating no more than 100 hours per year on a non-emergency basis, and shall burn only ultra low sulfur diesel as fuel. **Testing:** None required. **Monitoring/Record Keeping/Reporting/Other:** The owner or operator shall record the actual operating hours of each generator on a monthly basis. Reports of the recorded hours of operation shall be submitted semiannually. These sources are permitted to burn only ultra low diesel as fuel. The use of any other substances as fuel is prohibited without prior written approval from the Department. Fuel oil sulfur content shall be less than or equal to 0.0015 percent by weight. Fuel oil supplier certification shall be obtained for each batch of oil received and stored on site. Reports of the recorded sulfur content shall be submitted semiannually.
C.14	**Equipment/Control Device ID:** Unit ID 03 (#1 OX Unit), Unit ID 05 (#2 OX Unit) (40 CFR 60, Subparts A and VVa) These units are subject to the requirements of 40 CFR 60, Subpart VVa. However, since these units are subject to the HON LDAR program under 40 CFR 63 Subpart H, they are required to comply only with the provisions of 40 CFR 63 Subpart H, per §63.160(b)(1).
C.15	**Equipment/Control Device ID:** BR-301 (#1 OX Reactor), DR-106 A/B (#2 OX Reactors) (40 CFR 60, Subparts A and III) These sources are subject to the requirements of 40 CFR 60, Subpart III. However, since these sources are or will be Group 2 HON process vents, they are required to comply only with the provisions of 40 CFR 63 Subpart G, per §63.110(d)(2)(ii).
C.16	**Equipment/Control Device ID:** BT-701 (#1 DHT), DT-403 (#2 DHT), BT-750 (#1 ERT), DT-450 (#2 ERT) (40 CFR 60, Subparts A and NNN) These sources are subject to the requirements of 40 CFR 60, Subpart NNN. However, since these sources will be Group 2 HON process vents, they are required to comply only with the provisions of 40 CFR 63 Subpart G, per §63.110(d)(5)(ii).
C.17	Prior to start up of equipment as allowed under this PSD construction permit, the facility shall continue to comply with the current established synthetic minor limitations as listed in the project description section. The facility shall notify the Department 15 days after completion of a project that

C. LIMITATIONS, MONITORING AND REPORTING CONDITIONS

Condition Number	Conditions
	would result in a synthetic minor limit no longer being applicable.

D. NESHAP PERIODIC REPORTING SCHEDULE SUMMARY

NESHAP Part	NESHAP Subpart	Compliance Monitoring Report Submittal Frequency	Reporting Period	Report Due Date
63	F & G	Semi-Annual (Periodic Report)	January 1 – June 30 July 1 – December 31	No later than 60 calendar days after the end of each 6-month period
63	H	Semi-Annual	January 1 – June 30 July 1 – December 31	No later than 60 days after the end of each reporting per
63	ZZZZ (Emergency Engines)	N/A	N/A	N/A

1. This table summarizes only the periodic compliance reporting schedule. Additional reports may be required. See specific NESHAP Subpart for additional reporting requirements and associated schedule.
2. This reporting schedule does not supersede any other reporting requirements including but not limited to 40 CFR Part 60, 40 CFR Part 61, 40 CFR Part 63, and/or Title V. The MACT reporting schedule may be adjusted to coincide with the Title V reporting schedule with prior approval from the Department in accordance with 40 CFR 63.10(a)(5). This request may be made 1 year after the compliance date for the associated MACT standard.

E. NESHAP – CONDITIONS

Condition Number	Conditions
E.1	All NESHAP notifications and reports shall be sent to the Manager of the Air Toxics Section, South Carolina Department of Health and Environmental Control - Bureau of Air Quality.
E.2	All NESHAP notifications and the cover letter to periodic reports shall be sent to the United States Environmental Protection Agency (US EPA) at the following address or electronically as required by the specific subpart: **US EPA, Region 4** **Air, Pesticides and Toxics Management Division** **61 Forsyth Street SW** **Atlanta, GA 30303**
E.3	This facility has processes subject to the provisions of S.C. Regulation 61-62.63 and 40 CFR Part 63,

E. NESHAP – CONDITIONS

Condition Number	Conditions
	National Emission Standards for Hazardous Air Pollutants, Subparts A and F, National Emission Standards For Organic Hazardous Air Pollutants From The Synthetic Organic Chemical Manufacturing Industry. Existing affected sources shall be in compliance with the requirements of these Subparts on the compliance date, unless otherwise noted. Any new affected sources shall comply with the requirements of these Subparts upon initial start-up unless otherwise noted.
E.4	This facility has processes subject to the provisions of S.C. Regulation 61-62.63 and 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants, Subparts A and G, National Emission Standards For Organic Hazardous Air Pollutants From The Synthetic Organic Chemical Manufacturing Industry For Process Vents, Storage Vessels, Transfer Operations, And Wastewater. Existing affected sources shall be in compliance with the requirements of these Subparts on the compliance date, unless otherwise noted. Any new affected sources shall comply with the requirements of these Subparts upon initial start-up unless otherwise noted.
E.5	This facility has processes subject to the provisions of S.C. Regulation 61-62.63 and 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants, Subparts A and H, National Emission Standards For Organic Hazardous Air Pollutants For Equipment Leaks. Existing affected sources shall be in compliance with the requirements of these Subparts on the compliance date, unless otherwise noted. Any new affected sources shall comply with the requirements of these Subparts upon initial start-up unless otherwise noted.
E.6	This facility has processes subject to the provisions of S.C. Regulation 61-62.63 and 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants, Subparts A and ZZZZ, National Emission Standards For Organic Hazardous Air Pollutants For Stationary Reciprocating Internal Combustion Engines (RICE). Existing affected sources shall be in compliance with the requirements of these Subparts on the compliance date, unless otherwise noted. Any new affected sources shall comply with the requirements of these Subparts upon initial start-up unless otherwise noted.

F. AMBIENT AIR STANDARDS REQUIREMENTS

Condition Number	Conditions
F.1	Air dispersion modeling (or other method) has demonstrated that this facility's operation will not interfere with the attainment and maintenance of any state or federal ambient air standard. Any changes in the parameters used in this demonstration may require a review by the facility to determine continuing compliance with these standards. These potential changes include any decrease in stack height, decrease in stack velocity, increase in stack diameter, decrease in stack exit temperature, increase in building height or building additions, increase in emission rates, decrease in distance between stack and property line, changes in vertical stack orientation, and installation of a rain cap that impedes vertical flow. Parameters that are not required in the determination will not invalidate the demonstration if they are modified. The emission rates used in the determination are listed in Attachment - Emission Rates for Ambient Air Standards of this permit. Higher emission rates may be administratively incorporated into Attachment - Emission Rates for Ambient Air Standards of

F. AMBIENT AIR STANDARDS REQUIREMENTS

Condition Number	Conditions
	this permit provided a demonstration using these higher emission rates shows the attainment and maintenance of any state or federal ambient air quality standard or with any other applicable requirement. Variations from the input parameters in the demonstration shall not constitute a violation unless the maximum allowable ambient concentrations identified in the standard are exceeded. The owner/operator shall maintain this facility at or below the emission rates as listed in Attachment - Emission Rates for Ambient Air Standards, not to exceed the pollutant limitations of this permit. Should the facility wish to increase the emission rates listed in Attachment - Emission Rates for Ambient Air Standards, not to exceed the pollutant limitations in the body of this permit, it may do so by the administrative process specified above. This is a State Only enforceable requirement.

G. PERIODIC REPORTING SCHEDULE

Compliance Monitoring Report Submittal Frequency	Reporting Period (Begins on the startup date of the source)	Report Due Date
Quarterly	January-March April-June July-September October-December	April 30 July 30 October 30 January 30
Semiannual	January-June April-September July-December October-March	July 30 October 30 January 30 April 30
Annual	January-December April-March July-June October-September	January 30 April 30 July 30 October 30
Note: This reporting schedule does not supersede any federal reporting requirements including but not limited to 40 CFR Part 60, 40 CFR Part 61, and 40 CFR Part 63. All federal reports must meet the reporting time frames specified in the federal standard unless the Department or EPA approves a change.		

H. REPORTING CONDITIONS

Condition Number	Conditions
H.1	Reporting required in this permit, shall be submitted in a timely manner as directed in the Periodic Reporting Schedule of this permit.

H. REPORTING CONDITIONS

Condition Number	Conditions
H.2	All reports and notifications required under this permit shall be submitted to the person indicated in the specific condition at the following address: **2600 Bull Street** **Columbia, SC 29201** The contact information for the local Environmental Affairs Regional office can be found at: **http://www.scdhec.gov**
H.3	The owner/operator shall submit written notification to the Director of Air Permitting of the date construction is commenced, postmarked within 30 days after such date.
H.4	Unless elsewhere specified within this permit, all reports required under this permit shall be submitted to the Manager of the Technical Management Section, Bureau of Air Quality.
H.5	(S.C. Regulation 61-62.1, Section II.J) For sources not required to have continuous emissions monitors, any malfunction of air pollution control equipment or system, process upset or other equipment failure which results in discharges of air contaminants lasting for one hour or more and which are greater than those discharges described for normal operation in the permit application shall be reported to the Department's local Environmental Affairs Regional office within 24 hours after the beginning of the occurrence. The owner/operator shall also submit a written report within 30 days of the occurrence. This report shall be submitted to the Manager of the Technical Management Section, Bureau of Air Quality and shall include, at a minimum, the following: 1. The identity of the stack and/or emission point where the excess emissions occurred; 2. The magnitude of excess emissions expressed in the units of the applicable emission limitation and the operating data and calculations used in determining the excess emissions; 3. The time and duration of excess emissions; 4. The identity of the equipment causing the excess emissions; 5. The nature and cause of such excess emissions; 6. The steps taken to remedy the malfunction and the steps taken or planned to prevent the recurrence of such malfunction; 7. The steps taken to limit the excess emissions; and, 8. Documentation that the air pollution control equipment, process equipment, or processes were at all times maintained and operated, to the maximum extent practicable, in a manner consistent with good practice for minimizing emissions.

I. PERMIT EXPIRATION AND EXTENSION

Condition Number	Conditions
I.1	(S.C. Regulation 61-62.1, Section II.A.4) Approval to construct shall become invalid if construction: a. is not commenced within 18 months after receipt of such approval; b. is discontinued for a period of 18 months or more; or

I. PERMIT EXPIRATION AND EXTENSION

Condition Number	Conditions
	c. is not completed within a reasonable time as deemed by the Department. The Department may extend the construction permit for an additional 18-month period upon a satisfactory showing that an extension is justified. This request must be made prior to the permit expiration.
I.2	This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

J. PERMIT TO OPERATE

Condition Number	Conditions
J.1	(S.C. Regulation 61-62.1 Section II.F.2) The owner/operator or professional engineer in charge of the project shall certify that, to the best of his/her knowledge and belief and as a result of periodic observation during construction, the construction under application has been completed in accordance with the specifications agreed upon in the construction permit issued by the Department.
J.2	If construction is certified as provided in S.C. Regulation 61-62.1 Section II.F.2, the owner or operator, may operate the source in compliance with the terms and conditions of the construction permit until the operating permit is issued by the Department.
J.3	If construction is not built as specified in the permit application and associated construction permit(s), the owner/operator must submit to the Department a complete description of modifications that are at variance with the documentation of the construction permitting determination prior to commencing operation. Construction variances that would trigger additional requirements that have not been addressed prior to start of operation shall be considered construction without a permit.
J.4	(S.C. Regulations 61-62.1 Section II.F.3 and 61-62.70.7) The owner or operator shall submit a written request to the Director of Air Permitting for a new or revised operating permit to cover any new or altered source postmarked within 15 days after the actual date of initial startup unless a more stringent time frame is required by regulation. The request should be made using the appropriate Title V modification form.

K. GENERAL CONDITIONS

Condition Number	Conditions
K.1	The permittee shall pay permit fees to the Department in accordance with the requirements of S.C. Regulation 61-30, Environmental Protection Fees.
K.2	In the event of an emergency, as defined in S.C. Regulation 61-62.1, Section II.L, the owner or operator

K. GENERAL CONDITIONS

Condition Number	Conditions
	may document an emergency situation through properly signed, contemporaneous operating logs, and other relevant evidence that verify: 1. An emergency occurred, and the owner or operator can identify the cause(s) of the emergency; 2. The permitted source was at the time the emergency occurred being properly operated; 3. During the period of the emergency, the owner or operator took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and 4. The owner or operator gave a verbal notification of the emergency to the Department within 24 hours of the time when emission limitations were exceeded, followed by a written report within 30 days. The written report shall include, at a minimum, the information required by S.C. Regulation 61-62.1, Section II.J.1.c.i through viii. The written report shall contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This provision is in addition to any emergency or upset provision contained in any applicable requirement.
K.3	(S.C. Regulation 61-62.1, Section II.O) Upon presentation of credentials and other documents as may be required by law, the owner or operator shall allow the Department or an authorized representative to perform the following: 1. Enter the facility where emissions-related activity is conducted, or where records must be kept under the conditions of the permit. 2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit. 3. Inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit. 4. As authorized by the Federal Clean Air Act and/or the S.C. Pollution Control Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

L. EMISSIONS INVENTORY REPORTS - RESERVED

ATTACHMENT - Emission Rates for Ambient Air Standards

BP Amoco Chemical Company-Cooper River Plant
0420-0029-CU.R1
Page 1 of 2

The emission rates listed herein are not considered enforceable limitations but are used to evaluate ambient air quality impact. Until the Department makes a determination that a facility is causing or contributing to an exceedance of a state or federal ambient air quality standard, increases to these emission rates are not in themselves considered violations of these ambient air quality standards (see Ambient Air Standards Requirements).

AMBIENT AIR QUALITY STANDARDS - STANDARD NO. 2					
Emission Point ID	**Modeled Emission Rates (lbs/hr)**				
	PM_{10}	**$PM_{2.5}$**	**SO_2**	**NO_X**	**CO**
#1ATMOS	--	--	--	--	14.00
#1HPVGTS	--	--	--	--	72.00
#1LPVGT (1)	--	--	--	--	--
#1OXGEN2	0.738	--	0.690	10.405	--
#2ATMOS	--	--	--	--	3.47
#2BULKLO	0.500	--	--	--	--
#2CRYSVE	0.540	--	--	--	20.00
#2DAYSIL	0.540	--	--	--	--
#2DRYEVE	0.260	--	--	--	--
#2FDDRUM	0.040	--	--	--	--
#2HPVGTS	0.111	--	0.008	1.468	1.238
#2NEWPTA	0.480	--	--	--	--
#2OXGEN3	0.754	--	0.429	25.770	--
#2PVS	--	--	--	--	75.00
#2SHIP	0.300	--	--	--	--
BOILER#3 – Low Load	2.540	--	47.62	8.492	7.778
BOILER#4 – Low Load	2.540	--	47.62	8.492	7.778
CVSCRUBR	1.21	--	--	--	24.00
DAYSILO1	0.42	--	--	--	--
DAYSILO2	0.42	--	--	--	--
DVSCRUBR	0.60	--	--	--	--
FEEDSLUR	0.10	--	--	--	--
ITEGEN	0.680	--	1.603	14.580	--
LCOMP1	1.800	--	3.000	3.500	--
LCOMP2	1.800	--	3.000	3.500	--
PTASTORA	1.68	--	--	--	--
RAWH2O	0.627	--	0.587	8.841	--
SCREENR3	0.10	--	--	--	--
SCREENR4	0.10	--	--	--	--

ATTACHMENT - Emission Rates for Ambient Air Standards

BP Amoco Chemical Company-Cooper River Plant
0420-0029-CU.R1
Page 2 of 2

AMBIENT AIR QUALITY STANDARDS - STANDARD NO. 2					
Emission Point ID	**Modeled Emission Rates (lbs/hr)**				
	PM_{10}	**$PM_{2.5}$**	**SO_2**	**NO_X**	**CO**
TASILOS	1.50	--	--	--	--
UTCOMP#1	0.91	--	0.85	12.80	--
UTCOMP#2	0.349	--	2.333	28.556	--
UTGEN#1	0.811	--	0.754	11.445	--

CLASS II PREVENTION OF SIGNIFICANT DETERIORATION - STANDARD NO. 7				
Emission Point ID	**Modeled Emission Rates (lbs/hr)**			
	$PM_{2.5}$	**PM_{10}**	**SO_2**	**NO_X**
#2BULKLO	0.500	--	--	--
#2CRYSVE	0.540	--	--	--
#2DAYSIL	0.540	--	--	--
#2DRYEVE	0.260	--	--	--
#2FDDRUM	0.040	--	--	--
#2HPVGTS	0.111	--	0.008	1.468
#2NEWPTA	0.480	--	--	--
#2OXGEN3	0.754	--	0.429	1.471
#2SHIP	0.300	--	--	--
BOILER#1	-25.588	--	-555.533	-74.890
BOILER#2	-25.588	--	-555.533	-74.890
BOILER#3	2.540	--	47.620	8.492
BOILER#4	2.540	--	47.620	8.492
ITEGEN	0.680	--	1.603	0.833
LCOMP1	1.800	--	3.000	3.500
LCOMP2	1.800	--	3.000	3.500
SCREENR3	0.01	--	--	--
SCREENR4	0.01	--	--	--
UTCOMP#2	0.349	--	2.333	28.556

Appendix E

Draft Statement of Basis 0420-0029-CU.R1

S.C. Department of Health and Environmental Control

STATEMENT OF BASIS

BAQ Air Permitting Division

Company Name:	BP Amoco Chemical Company – Cooper River Plant	**Permit Writer:**	James C. Robinson
Permit Number:	0420-0029-CU.R1	**Date:**	**DRAFT**

EXPEDITED REVIEW: Accepted into Expedited Program December 20, 2017.
DATE APPLICATION RECEIVED: December 14, 2017
DATE OF OCRM APPROVAL: January 29, 2018

FACILITY DESCRIPTION: BP Amoco Chemical Company – Cooper River Plant (BPCR) produces only Purified Terephthalic Acid (PTA). PTA is used to make polyester fibers and films. The major raw materials in the production of PTA are Paraxylene (Px), acetic acid, caustic soda, and hydrogen. Plant operation consists mainly of: 1) utilities 2) production of crude TA, 3) purification into PTA, 4) product loading/ shipping, and 5) waste treatment along with some additional areas at the plant. There are two units that manufacture PTA: Cooper River #1 (CR#1), which consists of the #1 Oxidation (OX) Unit and the #1 PTA Unit; and Cooper River #2 (CR#2), which consists of the #2 Oxidation (OX) Unit and the #2 PTA Unit. The #1 and #2 OX Units produce crude TA and the #1 and #2 PTA Units purifies the crude TA, to make PTA.

PROJECT DESCRIPTION: The facility is proposing to change the method of operation of the #1 OX Unit. The facility has three (3) overhead condensers on its #1 Ox Unit Reactor, of which the facility currently draws a solvent/water mixture from Condensers 2 and 3. This mixture is sent to the dehydration tower (DHT), equipment ID BT-701, and the low pressure absorber (LPA), equipment ID BT-603, for solvent recovery. The facility is proposing to draw from all three condensers, as this provides better solvent and catalyst recovery and a more stable operation. This in turns provides a significant operational savings annually. The facility is also requesting to increase the CO BACT limit for #1 OX LPA (BT -603) from 4.1 lb/hr to 14 lb/hr, based on a 30-day rolling average.

In addition to this above-mentioned modification, the facility proposes to voluntarily decrease the CO BACT limit for the high pressure vent gas treatment system (HPVGTS) from 87.9 lb/hr to 72.0 lb/hr, based on a 30-day rolling average. This change, in effect, reduces facility wide CO emissions 6 lb/hr and 26.3 tpy.

The changes to these two CO BACT limits require revising the PSD construction permit 0420-0029-CU and the associated preliminary and final determinations. Only the portions of these three documents affected by these changes will be revised. The documents will also have general updates due to template changes.

SOURCE TEST REQUIREMENTS: In order to monitor and determine if the BACT emission limit for the #1 OX LPA is being met, the facility will be required to perform an initial source test 180 days after start-up of this modification, and once every three years thereafter.

EMISSIONS: This modification will cause an increase of carbon monoxide (CO) emissions from the LPA because the solvent/water mixture from the first condenser contains a higher concentration of CO. CO is an unwanted by-product of the reaction, and is released from the solvent/water mixture during the separation process in the DHT. CO then vents to the atmosphere through the LPA. There are no other pollutants affected by this project.

Note: Facility wide emissions of CO decrease due to the facility's proposal to voluntary reduce the CO BACT limit of the high pressure vent gas treatment system.

Company Name:	BP Amoco Chemical Company – Cooper River Plant	**Permit Writer:**	James C. Robinson
Permit Number:	0420-0029-CU.R1	**Date:**	**DRAFT**

FACILITY WIDE EMISSIONS		
Pollutant	**Uncontrolled Emissions**	**Controlled/Limited Emissions**
	TPY	**TPY**
PM	5,394.2	77.1
PM_{10}	5,356.2	73.0
$PM_{2.5}$	5,261.6	67.9
SO_2	190.9	189.0
NOx	495.7	324.9
CO	14,820.5	1206.7
VOC	2,587.2	576.5
Lead	1.0	1.0
GHG Mass	482,000	479,586
GHG CO_2e	484,519	480,031
Highest HAP (Paraxylene)	227.9	58.5
Total HAP	1688.1	128.6

OPERATING PERMIT STATUS

BPCR is a Title V Source for PM_{10}, $PM_{2.5}$, NOx, CO, SO_2, VOC, CO_2e, and single and combined HAPs. BPCR is a "28 Source Category" PSD major source (PTE >100 TPY) for PM, PM_{10}, $PM_{2.5}$, NOx, CO, SO_2, VOC, and CO_2e. BPCR currently operates under an existing TV operating permit. A timely TV renewal application was submitted on February 24, 2012.

REGULATORY APPLICABILITY REVIEW	
Regulations	**Comments/Periodic Monitoring Requirements**
Section II.E – Synthetic Minor	There no synthetic minor limits being established for this project.
Standard No. 1	No fuel burning sources are being modified with this project. Project will NOT require incremental steam usage from the two existing boilers.
Standard No. 3 (state only)	This project will not change applicable requirements for this regulation.
Standard No. 4	This project will not change applicable requirements for this regulation.
Standard No. 5	This project does not contain any sources regulated under this standard.
Standard No. 5.2	No fuel burning sources are being modified with this project.
Standard No. 7	The proposed project is a change in method of operation that is subject to PSD review and will have CO emissions increases requiring a BACT analysis. The facility is proposing to increase the BACT limit of the LPA (BT-603) from 4.1 lb/hr to 14 lb/hr of CO. Additionally, the facility proposes to voluntarily decrease the CO BACT limit of the high pressure vent gas treatment system (HPVGTS) from 87.9 lb/hr to 72.0 lb/hr. (See Std 7 Table below for proposed BACT limits)
61-62.6	Fugitive PM (Dust) emissions are not associated with this project.
40 CFR 60 and 61-62.60	This project will not change applicable requirements for this regulation.
40 CFR 61 and 61-62.61	This project will not change applicable requirements for this regulation.
40 CFR 63 and 61-62.63	This project will not change applicable requirements for this regulation.
61-62.68	This project will not change applicable requirements for this regulation.
40 CFR 64 (CAM)	This project will not change applicable requirements for this regulation.

AMBIENT AIR STANDARDS REVIEW	
Regulations	**Comments/Periodic Monitoring Requirements**
Standard No. 2	Facility has demonstrated compliance through modeling for AAQS; see modeling summary dated 1/16/18. No operational restriction has been established to ensure compliance with the modeled emission rates.
Standard No. 7.c	This facility has demonstrated compliance through modeling for the PSD Class II increments for Berkeley County; see modeling summary dated 1/16/18.
Standard No. 8 (state only)	No modeling review was required for this standard.

Standard No. 7 Proposed BACT Limits			
Equipment	**Pollutant**	**BACT Limit**	**Control Method**
#1 OX Low Pressure Absorber	CO	14.0 lb/hr	N/A
#1 OX HPVGTS	CO	72.0 lb/hr	N/A

PUBLIC NOTICE

This construction permit(s) will undergo a 30-day public notice period to modify the CO BACT limits for the #1 OX Low Pressure Absorber and the #1 OX HPVGTS, in accordance with SC Regulation 61-62.1, Section II.N and SC Regulation 61-62.5, Standard 7(q). The comment period was open from May 25, 2018 to June 23, 2018 and was placed on the BAQ website during that time period.

SUMMARY AND CONCLUSIONS

It has been determined that this source, if operated in accordance with the submitted application, will meet all applicable requirements and emission standards.

Appendix F

Public Notice of Draft PSD Construction Permit

PUBLIC NOTICE

State of South Carolina (SC)
Department of Health and Environmental Control (DHEC)
Bureau of Air Quality (BAQ)
2600 Bull Street
Columbia, SC 29201
(803) 898-4123

Notice of a Draft Air Prevention of Significant Deterioration (PSD) Construction Permit
PUBLIC NOTICE #18-019-PSD

COMMENT PERIOD: Public Notice will begin on **May 25, 2018** and will end at close of business, which is 5:00 p.m. on **June 23, 2018**.

BP Amoco Chemical Company-Cooper River Plant (BPCR)
1306 Amoco Drive
Wando, South Carolina 29492
(Berkeley County)
AIR PERMIT # 0420-0029-CU

(BPCR) has applied to the SC DHEC, BAQ, for a Prevention of Significant Deterioration (PSD) air construction permit to change Carbon Monoxide (CO) Best Available Control Technology (BACT) limits at its existing facility. A Preliminary Determination, draft Construction Permit, and draft Statement of Basis have been written by the BAQ outlining this proposed project and applicable regulations. In addition to other state and federal air quality regulations, the draft permit is subject to review under SC DHEC Regulation 61-62.5, Standard No. 7 “Prevention of Significant Deterioration (PSD).” This regulation is equivalent to Title 40 of the Code of Federal Regulations, Part 52.21 “Prevention of Significant Deterioration of Air Quality.” Under these regulations, a facility must demonstrate that it will not significantly deteriorate the air quality in its region prior to constructing or modifying sources of air pollutants. The draft permit has not yet been approved and is open to comment from the public, the United States Environmental Protection Agency (EPA), the Federal Land Managers, the chief executives of Berkeley, the Cities of Goose Creek, North Charleston and Mount Pleasant, and the Berkeley-Charleston-Dorchester Council of Government.

BPCR produces only purified Terephthalic Acid (PTA) to make polyester fibers and films. The facility is proposing to draw from three condensers rather than 2, as this provides better solvent and catalyst recovery and a more stable operation. The facility is also requesting to increase the CO BACT limit for the #1 Oxidizer (OX) from 4.1 pounds per hour (lb/hr) to 14 lb/hr, based on a 30-day rolling average. In addition, the facility proposes to decrease the CO BACT limit for the high pressure vent gas treatment system (HPVGTS) from 87.9 lb/hr to 72.0 lb/hr, based on a 30-day rolling average. Emissions generated by this facility as a result of the proposed project will include CO.

Air dispersion modeling has indicated that the release of emissions from this facility will not cause or contribute to an exceedance of the National Ambient Air Quality Standards (NAAQS). There will be no Class I Areas impacted and no degree of increment consumption resulting from this proposed project.

Pursuant to Part 70.7(d)(1)(v), this construction permit will be incorporated as an administrative amendment into the existing Title V permit with no additional public comment period. All public participation and EPA requirements will be fulfilled with notice of the construction permit action. All emissions limitations and conditions in the draft PSD construction permit have been written in accordance with the SC Title V Operating Permit Program.

Interested persons may review the materials drafted and maintained by DHEC for this facility and submit written comments on the draft permit by the end of the public notice period listed above, to Ruthie Hall at the above DHEC address or by e-mail at hallmr@dhec.sc.gov. All comments received by the end of the notice period, will be considered when making a decision to approve, disapprove, or modify the draft permit. Where there is a significant amount of public interest, DHEC may hold a public hearing to receive additional comments. Public hearing requests should be made in writing to Ruthie Hall at the above DHEC address or by e-mail. If a public hearing is requested and scheduled, notice will be given thirty (30) days in advance. If you have questions concerning the draft permit, please contact James Robinson at the phone number listed above. A final review request may be filed after a permit decision has been made. Information regarding final review procedures is available from DHEC's legal office at the above address or by calling (803) 898-3350. Information relative to the draft permit will be made available for review through the end of the notice period listed above, at the DHEC Columbia Office listed above and at the following location:

SC DHEC, Charleston BEHS Office, 1362 McMillan Avenue, Suite 300, Charleston, SC 29405

Information on permit decisions and hearing procedures is available by contacting DHEC at either address listed above. Copies of a draft permit or other related documents may be requested in writing to the Freedom of Information Office; fees may apply. Please bring this notice to the attention of persons you know will be interested in this matter.

This public notice, along with the Preliminary Determination which includes the draft permit and draft statement of basis, may be viewed through the end of the notice period on DHEC's website at: http://www.scdhec.gov/PublicNotices/.

Appendix G

Correspondence

BAQ in receipt of an Expedited Prevention of Significant Deterioration (PSD) Air Permit Application for BP Amoco Chemical Company - Cooper River Plant (0420-0029)

Robinson, James C.

Wed 12/20/2017 1:44 PM

Sent Items

To:Andrews, Marianne <Marianne.Andrews2@bp.com>; rvandenmeiracker@trcsolutions.com <rvandenmeiracker@trcsolutions.com>;

Cc:Boyce, Lawra <boycelc@dhec.sc.gov>; Glass, John <glassjp@dhec.sc.gov>; AIR_ENG_ADMIN <AIR_ENG_ADMIN@dhec.sc.gov>; Humphries, Diane <HUMPHRDM@dhec.sc.gov>; McCaslin, Steven <mccaslsd@dhec.sc.gov>; Boswell, Wendy <BOSWELWM@dhec.sc.gov>;

1 attachments (7 MB)

2017-12-14_0420-0029.CP.pdf;

The Bureau of Air Quality (BAQ) received an expedited PSD application from BP Amoco Chemical Company - Cooper River Plant, Wando, SC on December 14, 2017. The application was for the modification of equipment in the #1 Oxidation Unit. The completeness review period for the application officially began on this date and the application has been deemed technically complete as of December 20, 2017.

We need your assistance in meeting the time frame goals. We ask that you commit to assisting us with public participation activities, such as participating in answering questions from the public about the proposed project during any public meeting and/or public hearings that may be requested and held and helping us respond to any comments that may be received during the public comment period. We also ask that you commit to providing timely answers to any additional information that may be requested during the review. If you still wish to enter the expedited program and agree to the above conditions, please respond to this email and submit payment in the amount of $5,000.

If paying the expedited fee by check, make the check out to “SC DHEC.” The check should be received within 5 business days of this notification and should be sent to the attention of the “Director of Air Permitting Division – BAQ”.

If you wish to pay by electronic check, let us know who to email an invoice to. Once the invoice is created and emailed you will have one business day to pay. You will need the invoice number and then you may log on to the website at the address below to pay the expedited fee.

> https://web.sc.gov/dheconlineinvoicepaymentsystem/invoicegroupselection.aspx

If you have questions, please contact me at (803) 898-0660 or by e-mail.

James C. Robinson, P.E.
Environmental Engineer
Air Permitting Division
Bureau of Air Quality
Office: (803) 898-0660
Connect: www.scdhec.gov Facebook Twitter

dhec

Healthy People. Healthy Communities.

Prevention of Significant Deterioration (PSD) Air Permit Application for BP Amoco Chemical Company - Cooper River Plant (0420-0029)

Robinson, James C.

Wed 12/20/2017 2:58 PM

To:shepherd.lorinda@epa.gov <shepherd.lorinda@epa.gov>; ceron.heather@epa.gov <ceron.heather@epa.gov>;

Cc:Boswell, Wendy <BOSWELWM@dhec.sc.gov>; Humphries, Diane <HUMPHRDM@dhec.sc.gov>;

1 attachments (7 MB)

2017-12-14_0420-0029.CP.pdf;

The Bureau of Air Quality (BAQ) received an expedited PSD application from BP Amoco Chemical Company - Cooper River Plant, Wando, SC on December 14, 2017. The application was for the change in operation of equipment in the #1 Oxidation Unit, to reduce operating costs. The completeness review period for the application officially began on this date and the application has been deemed technically complete as of December 20, 2017. It will now undergo technical review for a preliminary determination under the requirements of SC Regulation 61-62.5, Standard No. 7 (PSD).

An electronic copy of the PSD construction permit application is attached for your review. Please direct all written comments to my attention at the address below. If I can be of further assistance, please contact me at (803) 898-0660 or by E-mail.

James C. Robinson, P.E.
Environmental Engineer
Air Permitting Division
Bureau of Air Quality
Office: (803) 898-0660
Connect: www.scdhec.gov Facebook Twitter

dhec
Healthy People. Healthy Communities.

Re: CO Control Efficiency

Robinson, James C.

Wed 12/20/2017 5:21 PM

PSD Revision

To:rvandenmeiracker@trcsolutions.com <rvandenmeiracker@trcsolutions.com>;

The One Drive folder wouldn't give me access.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Wednesday, December 20, 2017 4:32:15 PM
To: Robinson, James C.
Cc: Andrews, Marianne; Bailey, William
Subject: CO Control Efficiency

James,

Earlier today you asked me about the basis for the 95% CO control listed in the BACT analysis. Our approach was based on the determination in Dragonslayer application that VOC control was between 98% to 99%. Since it takes higher temperatures, better mixing, and longer residence times (the 3-T's) to destroy CO than a typical hydrocarbon, we lowered the control to 95%. You also get very little heat release from the combustion of CO so there is little chance of being self-sustaining thus requiring more fuel to be burned to maintain temperature which only contributes more CO. So the net CO is not much different even if you improve the design.

I also found a few resources that provide some basis for CO control in the range or 90% and listed them below.

1. Catalytic oxidation of CO to CO2 at efficiencies of approximately 70 percent for 2SLB engines and 90 percent for 4SLB engines is demonstrated. AP-42, 3.2 Natural Gas-fired Reciprocating Engines, Section 3.2.4.2, page 3.2-5 (https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf).

2. From the Document: *EPA-450/3-79-006, Control Techniques for Carbon Monoxide Emissions*, properly designed and operated, a catalytic incineration system can consistently achieve CO removal efficiencies of greater than 90 percent. Higher efficiencies (greater than 95 percent) will require greater capital outlays than what we considered for this project. (A copy of this document is in the OneDrive folder)

Please let me know if you have any questions or need further information.

Thanks,

Rob

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

VandenMeiracker, Robert shared "00001Z4I" with you.

VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>

Wed 12/20/2017 5:24 PM

PSD Revision

To:Robinson, James C. <robinsjc@dhec.sc.gov>;

Here's the document that VandenMeiracker, Robert shared with you.

This link only works for the direct recipients of this message.

00001Z4I

Open

Microsoft OneDrive

EPA-450/3-79-006

Control Techniques for Carbon Monoxide Emissions

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

June 1979

This report has been reviewed by the Emission Standards and Engineering Division of the Office of Air Quality Planning and Standards, EPA, and approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available through the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711, or from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161.

Publication No. EPA-450/3-79-006

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1. INTRODUCTION AND SUMMARY

The document "Control Techniques for Carbon Monoxide Emissions from Stationary Sources (AP-65)," was published by the U.S. Environmental Protection Agency in March 1970. It was one of a series of documents which summarized control technique information for criteria air pollutants. Section 108(b) of the Clean Air Act, as amended, 42 USC paragraph 7401 et. seq., instructs the Administrator to issue information on air pollution control techniques simultaneously with the issuance of new or revised air quality criteria, as follows:

> "... the Administrator shall, after consulation with appropriate advisory committees and federal departments and agencies, issue to the States and appropriate air pollution control agencies information on air pollution control techniques, which information shall include data relating to the cost of installation and operation, energy requirements, emission reduction benefits, and environmental impact of the emission control technology. Such information shall include such data as are available on available technology and alternative methods of prevention and control of air pollution. Such information shall also include data on alternative fuels, processes, and operating methods which result in elimination or significant reduction of emissions."

This control techniques document was written in compliance with Section 108(c), which requires the Administrator to review, and where appropriate, modify and reissue any air quality criteria or information on control techniques. Thus, this document represents an updated and expanded version of AP-65.

It includes information on significant stationary sources of carbon monoxide emissions as well as available methods for control of carbon monoxide emissions from mobile sources.

This document characterizes carbon monoxide emission sources and controls for use by states in revising State Implementation Plans (SIP's). It is intended for use by state and local air pollution control engineers to provide basic available information on carbon monoxide emissions from mobile sources, stationary combustion sources, and industrial process sources. Both demonstrated and feasible control strategies are presented for each source. Information is also provided on emission reduction benefits, energy requirements of controls, and annualized and operating costs of controls.

Chapter 2 of this document presents background information on carbon monoxide formation and lists significant sources of CO. Recent estimates of carbon monoxide emissions and current emission factors are listed. This chapter also includes a brief discussion of sampling and analytical methods for carbon monoxide.

Chapter 3 summarizes current measures to control carbon monoxide emissions from mobile sources. Information is included which will assist states in developing transportation measures for CO control through State Implementation Plans.

Chapter 4 (internal combustion) and Chapter 5 (external combustion) discuss methods for control of carbon monoxide emissions from combustion sources.

Chapter 6 describes the techniques employed to control carbon monoxide emissions from industrial sources and gives information on the energy requirements, costs and environmental aspects of these techniques.

Chapter 7 describes the techniques used for control of specific industrial sources and gives information on energy, cost, and environmental aspects.

The control methods described in this document represent information from many technical fields. The proper choice of a method of controlling carbon monoxide emissions from a specific source depends on several factors other than source characteristics. No attempt has been made in this document to review all the possible combinations of control techniques that may be used.

2. CHARACTERIZATION OF CARBON MONOXIDE EMISSIONS

Most of the material presented in this section provides background information on manmade carbon monoxide sources and emissions. Information on natural sources of carbon monoxide is given in a companion document "Air Quality Criteria for Carbon Monoxide," revised 1979. Also included is information on the formation of carbon monoxide and a description of standard methods for analysis of source and ambient CO concentrations.

2.1 FORMATION OF CARBON MONOXIDE

Carbon monoxide is formed as an intermediate product of reactions between carbonaceous fuels and oxygen.[1] When less than the theoretical amount of oxygen required for complete combustion is supplied, CO is a final product of the reaction. Under these conditions, CO concentrations may exceed 50,000 ppm.

Formation of the oxides of carbon is a simple process only when pure carbon and pure oxygen are involved. The burning of carbonaceous fuels, in general, is a very complicated process involving formation of CO before CO_2 is formed.[1] If the temperature of combustion is high enough, dissociation of the CO_2 begins:

$$CO_2 \rightleftharpoons CO + O$$

Table 2-1 shows the percentage dissociation of CO_2 to CO as a function of temperature.

TABLE 2-1

DISSOCIATION OF CO_2 TO CO

TEMPERATURE	PERCENTAGE DISSOCIATION
727°C (1,340°F)	2×10^{-5}
1127°C (2,060°F)	1.5×10^{-2}
1527°C (2,780°F)	5.5×10^{-1}
1627°C (2,960°F)	1.0
1727°C (3,140°F)	1.8
1924°C (3,495°F)	5.0

Source: Reference 2

Actually, CO is a very stable substance at high temperature, as indicated by Table 2-1. In order for a chemical reaction to take place, chemical bonds must be broken and formed. Bond energies are a measure of the difficulty in breaking a chemical bond. Table 2-2 indicates a higher bond energy for CO than for acetylene, which is notorious for its stability at electric arc temperatures; CO is indeed known to be stable at very high temperature. Conversely, propane is easily cracked or decomposed at moderate temperatures, and the bond energy is seen to be low. The bond energy for CO_2 is moderately low, and experience shows that it is not difficult to remove an atom of oxygen from CO_2 by dissociation to form CO. For these reasons then, a second mechanism of CO formation is high-temperature dissociation of CO_2, or hindering of the combination of CO and oxygen by virtue of temperature. Thus, raising the temperature increases the concentration of CO in the thermodynamic sense.

TABLE 2-2

BOND ENERGIES OF SOME SIMPLE CHEMICAL SUBSTANCES

SUBSTANCE	BOND	BOND ENERGY, Kcal/mol
Carbon monoxide	C-O	256.7
Carbon dioxide	$O=C-O$	128
Propane	C_3H_7-H	98
Acetylene	$HC \equiv CH$	230

Source: Reference 3

The reaction rates increase with temperature. Increase of oxygen concentration tends to decrease the CO concentration by affording a greater chance for collision of CO and oxygen molecules (actually, hydroxyl radicals) to form CO_2.[1]

2.2 SOURCES OF CARBON MONOXIDE EMISSIONS

There are numerous manmade sources of carbon monoxide emissions. These sources can be categorized into two broad groups--mobile and stationary. Figure 2-1 shows a breakdown of the stationary sources of carbon monoxide which are investigated in this report. Chapter 3 discusses in detail the sources of CO within the mobile category. Chapters 4, 5, and 7 investigate the sources within the stationary source category. These sources were chosen based upon their contribution to the total yearly tonnage of carbon monoxide emissions in the U.S.

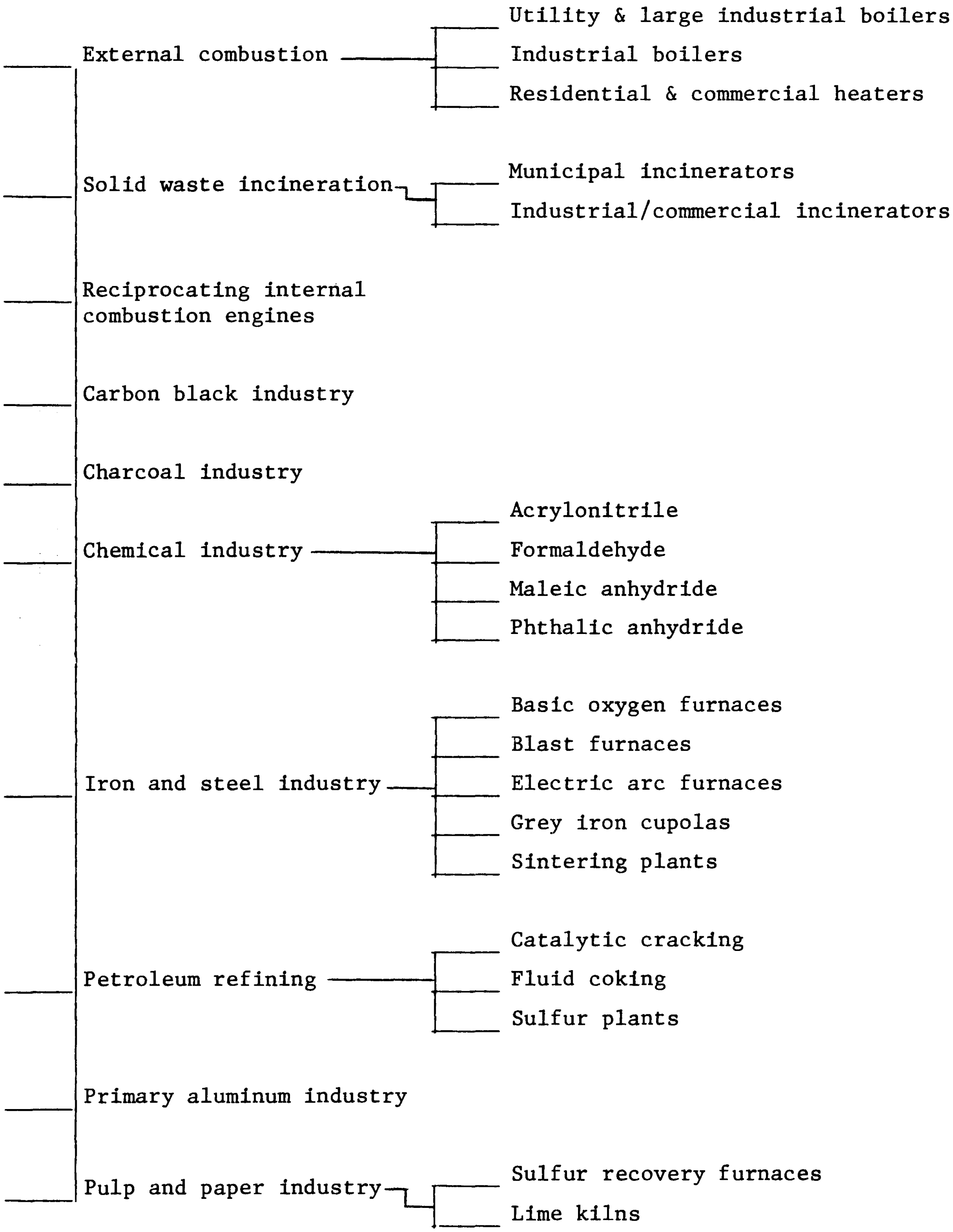

FIGURE 2-1. STATIONARY MANMADE SOURCES OF CARBON MONOXIDE

2.3 CARBON MONOXIDE EMISSION ESTIMATES AND EMISSION FACTORS

EPA estimates of 1977 nationwide CO emissions are given in Tables 2-3 through 2-8. As these tables indicate, a wide variety of transportation, combustion, industrial, and solid waste disposal sources contribute to the total mass emissions of carbon monoxide. Table 2-3 shows that about 83 percent of all nationwide CO emissions are from transportation sources. As shown in Table 2-4, about 90 percent of the CO emissions from transportation sources are from motor vehicles. CO emissions from gasoline powered passenger cars comprise about 63 percent of the CO emissions from motor vehicles (Table 2-5). CO emissions from combustion, industrial, and solid waste disposal categories are on the order of hundreds of thousands of metric tons as compared with millions of metric tons from motor vehicles.

Table 2-9 summarizes EPA uncontrolled carbon monoxide emission factors for various stationary sources. Chapter 3 includes information on emission factors for mobile sources.

2.4 CARBON MONOXIDE EMISSION TRENDS AND PROJECTIONS

Nationwide carbon monoxide emission estimates have been made by the EPA's Office of Air Quality Planning and Standards for the years 1970 through 1977.[4] These estimates are presented in Table 2-10.

Although the categories are not as detailed as the ones in Tables 2-3 through 2-8, they are sufficient to show the year-to-year trends in CO emissions for the recent past. These estimates were made by EPA from internally consistent sets of data based on current emissions factors.[4]

As Table 2-10 indicates, changes in annual CO emission estimates are slight for the period 1970 through 1977. Emission estimates for highway

TABLE 2-3

SUMMARY OF 1977 NATIONWIDE CARBON MONOXIDE EMISSIONS[a] FROM ALL SOURCES - 10^6 METRIC TONS PER YEAR (10^6 tons/yr)

SOURCE	CO EMISSIONS
Transportation	85.7 (94.5)
Combustion	1.2 (1.3)
Industrial	8.3 (9.2)
Solid Waste Disposal and Wildfires	7.5 (8.3)
Total Emissions	102.7 (113.3)

Source: Reference 4

[a] Does not include carbon monoxide from natural sources.

TABLE 2-4

SUMMARY OF 1977 NATIONWIDE CARBON MONOXIDE EMISSIONS FROM TRANSPORTATION SOURCES - 10^3 METRIC TONS PER YEAR (10^3 tons/yr)

SOURCE		CO EMISSIONS
Motor Vehicles*		77170.6 (85066.0)
Aircraft		651.6 (718.3)
Commercial	151.3 (166.8)	
General Aviation	261.8 (288.6)	
Military	238.5 (262.9)	
Railroads		270.4 (298.0)
Diesel and Distillate	259.5 (286.0)	
Residual Oil	0.7 (0.8)	
Coal	10.2 (11.2)	
Vessels		1498.8 (1652.2)
Residual Oil	0.7 (0.8)	
Diesel Oil	29.8 (32.9)	
Gasoline	1463.5 (1613.2)	
Coal	4.8 (5.3)	
Off-Highway Use Farm Tractors		2291.0 (2527.4)
Gasoline	2179.2 (2404.2)	
Diesel	111.8 (123.2)	
Other Farm Equipment		238.0 (262.4)
Gasoline	232.4 (256.2)	
Diesel	5.6 (6.2)	
Construction		957.6 (1055.5)
Gasoline	734.5 (809.6)	
Diesel	223.1 (245.9)	
Snowmobiles	109.0 (120.2)	109.0 (120.2)
Small Utility Engines	1262.8 (1392.0)	1262.8 (1392.0)
Heavy Duty Engines		1177.2 (1297.7)
Gasoline	1125.9 (1241.1)	
Diesel	51.3 (56.6)	
Motorcycles	87.5 (96.5)	87.5 (96.5)
Total Mobile Source Emissions		85714.5 (94486.2)

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*See Table 2-5 for breakdown of emissions.

Source: Reference 4

TABLE 2-5

SUMMARY OF 1977 NATIONWIDE CARBON MONOXIDE EMISSIONS FROM VEHICLES - 10^3 METRIC TONS PER YEAR (10^3 tons/yr)

SOURCE TYPE	CO EMISSIONS		
	Urban	Rural	Total
Gasoline			
Passenger Cars	38,315 (42,235)	10,147 (11,185)	48,462 (53,420)
Light Duty Trucks	8,726 (9,619)	2,231 (2,459)	10,957 (12,078)
Heavy Duty Trucks	9,937 (10,954)	5,973 (6,584)	15,910 (17,538)
Motorcycles	476 (525)	163 (180)	640 (705)
Total Gasoline	57,455 (63,333)	18,514 (20,408)	75,969 (83,741)
Heavy Duty Trucks - Diesel	494 (545)	708 (780)	1,202 (1,325)
Total From Motor Vehicles	57,949 (63,878)	19,221 (21,188)	77,171 (85,066)

Source: Reference 4

TABLE 2-6

SUMMARY OF 1977 NATIONWIDE CARBON MONOXIDE EMISSIONS FROM COMBUSTION SOURCES - 10^3 METRIC TONS PER YEAR (10^3 tons/yr)

SOURCE	CO EMISSIONS	
Anthracite Coal		78.7 (86.8)
Electric Utilities	0.6 (0.7)	
Industrial	0.5 (0.5)	
Commercial-Institutional	0.1 (0.1)	
Residential	77.6 (85.5)	
Bituminous and Lignite Coal		318.1 (350.6)
Electric Utilities	212.8 (234.6)	
Industrial	26.8 (29.5)	
Commercial-Institutional	5.0 (5.5)	
Residential	73.5 (81.0)	
Residual Oil		95.4 (105.2)
Electric Utilities	50.7 (55.9)	
Industrial	24.0 (26.5)	
Commercial-Institutional	20.7 (22.8)	
Residential	0 (0)	
Distillate Oil		71.3 (78.6)
Electric Utilities	5.6 (6.2)	
Industrial	9.5 (10.5)	
Commercial-Institutional	17.3 (19.1)	
Residential	38.8 (42.8)	
Natural Gas		541.0 (596.3)
Electric Utilities	22.7 (25.0)	
Gas Pipelines and Plants	395.5 (436.0)	
Industrial	52.4 (57.8)	
Commercial-Institutional	24.2 (26.7)	
Residential	46.1 (50.8)	
Kerosene		6.0 (6.6)
Industrial	1.5 (1.6)	
Heating	4.5 (5.0)	
Liquid Propane Gas		9.8 (10.8)
Industrial	3.1 (3.4)	
Domestic-Commercial	6.7 (7.4)	

TABLE 2-6 (Continued)

SOURCE	CO EMISSIONS
Wood	41.7 (46.0)
Process Gas	3.3 (3.6)
Bagasse	8.8 (9.7)
Total	1174.1 (1294.2)

Source: Reference 4

TABLE 2-7

SUMMARY OF 1977 NATIONWIDE CARBON MONOXIDE EMISSIONS FROM INDUSTRIAL SOURCES - 10^3 METRIC TONS PER YEAR (10^3 tons/yr)

SOURCE	CO EMISSIONS	
Iron Foundries		1020.8 (1125.2)
Petroleum Refineries		2425.6 (2673.8)
FCC Units	2384.7 (2628.7)	
TCC Units	40.4 (44.5)	
Fluid Coking	0.5 (0.6)	
Process Heaters		24.5 (27.0)
Oil-Fired	5.1 (5.6)	
Gas-Fired	19.4 (21.4)	
Asphalt Roofing		11.9 (13.1)
Carbon Black		2184.2 (2407.7)
Gas	442.3 (487.6)	
Oil	1741.9 (1920.1)	
Channel	0 (0)	
Thermal	0 (0)	
Steelmaking		929.7 (1024.8)
Sintering	624.7 (688.6)	
BOF	99.2 (109.4)	
Electric Arc	205.7 (226.8)	
Coke Production		43.7 (48.2)
Beehive	0.4 (0.4)	
Byproduct	43.4 (47.8)	
Kraft Pulp and Paper		1105.7 (1218.8)
Charcoal		97.3 (107.2)
Petrochemicals		481.1 (530.3)
Acetic Acid	8.2 (9.0)	
Acrylonitrile	130.4 (143.7)	
Cyclohexanol	39.0 (43.0)	

Source: Reference 4

TABLE 2-7 (Continued)

SOURCE	CO EMISSIONS	
Dimethylterephthalate	55.7 (61.4)	
Ethylene Dichloride	14.2 (15.7)	
Formaldehyde	64.9 (71.5)	
Maleic Anhydride	117.8 (129.9)	
Phthalic Anhydride	50.9 (56.1)	
Total Industrial Emissions		8324.4 (9176.1)

Source: Reference 4

TABLE 2-8

SUMMARY OF 1977 NATIONWIDE CARBON MONOXIDE EMISSIONS FROM SOLID WASTE DISPOSAL AND WILDFIRES - 10^3 METRIC TONS PER YEAR (10^3 tons/yr)

SOURCE	CO EMISSIONS
Municipal Incinerators	155.6 (171.5)
Conical Incinerators	530.7 (585.0)
Other Incinerators	655.0 (722.0)
Open Burning	1291.6 (1423.7)
Prescribed Forest Burning	1016.0 (1120.0)
Prescribed Agricultural Burning	499.0 (550.0)
Forest Wildfires	3255.3 (3588.4)
Structure Wildfires	135.5 (149.4)
Total Emissions	7538.7 (8310.0)

Source: Reference 4

TABLE 2-9

EPA UNCONTROLLED CARBON MONOXIDE EMISSION FACTORS FOR SELECTED STATIONARY SOURCES

SOURCE/FUEL TYPE	EMISSION FACTOR
Boilers, Heaters, and Incineration	
Bituminous Coal	
Large Boilers [>29MW (>100x10^6 Btu/hr)]	0.5 kg/metric ton (1 lb/ton)
Intermediate Boilers [3-29MW (10-100x10^6 Btu/hr)]	1 kg/metric ton (2 lb/ton)
Small Combustion Units [<3MW (<10x10^6 Btu/hr)]	5 kg/metric ton (10 lb/ton)
Hand-Fired Units	45 kg/metric ton (90 lb/ton)
Fireplaces	45 kg/metric ton (90 lb/ton)
Lignite	
Pulverized Coal and Cyclone Units	0.5 kg/metric ton (1 lb/ton)
Stoker Units	1 kg/metric ton (2 lb/ton)
Anthracite Coal	
Pulverized Coal	0.5 kg/metric ton (1 lb/ton)
Traveling Grate Stokers	0.5 kg/metric ton (1 lb/ton)
Hand-Fired Units	45 kg/metric ton (90 lb/ton)
Fireplaces	45 kg/metric ton (90 lb/ton)
Fuel Oil	
Residual-Fired Large Boilers [>73MW (>250x10^6 Btu/hr)]	0.63 kg/10^3 liter (5 lb/10^3 gal)
Residuel-Fired Small and Intermediate Boilers [0.15-73MW (0.5-250x10^6 Btu/hr)]	0.63 kg/10^3 liter (5 lb/10^3 gal)
Distillate-Fired Small and Intermediate Boilers [0.15-73MW (0.5-250x10^6 Btu/hr)]	0.63 kg/10^3 liter (5 lb/10^3 gal)
Domestic Units [<0.15MW (<0.5x10^6 Btu/hr)]	0.63 kg/10^3 liter (5 lb/10^3 gal)
Orchard Heaters	2.8 kg/heater/hr (6.2 lb/heater/hr)

Source: Reference 5

TABLE 2-9 (Continued)

SOURCE/FUEL TYPE	EMISSION FACTOR
Boilers, Heaters, and Incineration (Cont'd)	
Natural Gas	
Power Plant	272 kg/$10^6 m^3$ (17 lb/10^6 ft^3)
Industrial Boilers	272 kg/$10^6 m^3$ (17 lb/10^6 ft^3)
Domestic and Commercial Units	320 kg/$10^6 m^3$ (20 lb/10^6 ft^3)
Liquid Propane Gas	
Industrial Units	0.18 kg/10^3 liter (1.5 lb/10^3 gal)
Domestic and Commercial Units	0.23 kg/10^3 liter (1.9 lb/10^3 gal)
Liquid Butane Gas	
Industrial Units	0.19 kg/10^3 liter (1.6 lb/10^3 gal)
Domestic and Commercial Units	0.24 kg/10^3 liter (2 lb/10^3 gal)
Wood	
Wood and Bark Boilers	1-30 kg/metric ton (2-60 lb/ton)
Wood Stoves	130 kg/metric ton (260 lb/ton)
Fireplaces	60 kg/metric ton (120 lb/ton)
Conical Incinerators	65 kg/metric ton (130 lb/ton)
Solid Waste Incineration	
Municipal Refuse	
Multiple Chamber	17.5 kg/metric ton charged (35 lb/ton)
Conical	65 kg/metric ton (130 lb/ton)
Industrial/Commercial	
Multiple Chamber	5 kg/metric ton charged (10 lb/ton)
Single Chamber	10 kg/metric ton charged (20 lb/ton)
Flue-Fed Single Chamber	10 kg/metric ton charged (20 lb/ton)
Open Burning	
General	42 kg/metric ton (85 lb/ton)
Agricultural Waste	16-154 kg/metric ton (33-309 lb/ton)

Source: Reference 5

TABLE 2-9 (Continued)

SOURCE/FUEL TYPE	EMISSION FACTOR
Boilers, Heaters, and Incineration (Cont'd)	
Automobile Body Burning	1.1 kg/automobile (2.5 lb/ automobile)
Sewage Sludge Incineration	Negligible
Reciprocating Internal Combustion Engines	
Gasoline Engines	
Small, 2-Stroke, General Utility	652 g/kWhr (486 g/hp-hr)
Small, 4-Stroke, General Utility	374 g/kWhr (279 g/hp-hr)
Farm Equipment (wheeled tractor)	192 g/kWhr (143 g/hp-hr)
Farm Equipment (non-tractor)	292 g/kWhr (218 g/hp-hr)
Heavy-Duty Construction Equipment	190-271 g/kWhr (142-202 g/hp-hr)
Industrial Engines	267 g/kWhr (199 g/hp-hr)
Diesel Engines	
Farm Equipment (wheeled tractor)	4.48 g/kWhr (3.34 g/hp-hr)
Farm Equipment (non-tractor)	5.47 g/kWhr (4.08 g/hp-hr)
Heavy-Duty Construction Equipment	2.41-5.90 g/kWhr (1.80-4.40 g/hp-hr)
Industrial Engines	4.06 g/kWhr (3.03 g/hp-hr)
Natural Gas-Fueled	
Heavy Duty Engines	7020 kg/10^6m^3 (430 lb/10^6 ft^3)
Electric Utility Turbines	
Gas-Fueled	1842 kg/10^6m^3 (115 lb/10^6 ft^3)
Oil-Fueled	1.85 kg/10^3 liter (15.4 lb/10^3 gal)
Industrial Process Sources	
Asphalt Roofing Manufacturing	
Asphalt Blowing	0.14 kg/metric ton asphalt (0.27 lb/ton)

Source: Reference 5

TABLE 2-9 (Continued)

SOURCE/FUEL TYPE	EMISSION FACTOR
Industrial Process Sources (Cont'd)	
Felt Saturation	1.45 kg/metric ton felt (2.9 lb/ton)
Carbon Black Manufacturing, Furnace Process	1300 kg/metric ton product (2600 lb/ton)
Charcoal Manufacturing	160 kg/metric ton product (320 lb/ton)
Chemical Industry	
Adipic Acid	58 kg/metric ton product (115 lb/ton)
Ammonia	100 kg/metric ton product (200 lb/ton)
Lime Manufacturing	1 kg/metric ton product (2 lb/ton)
Phthalic Anhydride	
O-Xylene Process	151 kg/metric ton product (301 lb/ton)
Naphthalene Process	50 kg/metric ton product (100 lb/ton)
Glass Manufacturing (melting furnace)	0-0.2 kg/metric ton product (0-0.5 lb/ton)
Iron and Steel Production	
Basic Oxygen Furnace	70 kg/metric ton steel (140 lb/ton)
Blast Furnace	875 kg/metric ton pig iron (1750 lb/ton)
Electric Arc Furnace	9 kg/metric ton steel (18 lb/ton)
Cupola Furnace	72.5 kg/metric ton charge (145 lb/ton)
Sinter Production	22 kg/metric ton product (44 lb/ton)

Source: Reference 5

TABLE 2-9 (Continued)

SOURCE/FUEL TYPE	EMISSION FACTOR
Industrial Process Sources (Cont'd)	
Petroleum Refining	
Fluid Catalytic Cracking Units	39.2 kg/m^3 feed (13,700 $lb/10^3$ bbl)
Moving Bed Catalytic Cracking Units	10.8 kg/m^3 feed (3,800 $lb/10^3$ bbl)
Pulp and Paper Manufacturing	
Kraft Pulping	
Recovery Furnace	1-30 kg/metric ton dried pulp (2-60 lb/ton)
Lime Kilns	5 kg/metric ton dried pulp (10 lb/ton)

Source: Reference 5

TABLE 2-10

CARBON MONOXIDE EMISSION TRENDS, 1970-1977

SOURCE CATEGORY	NATIONWIDE EMISSION ESTIMATES 10^6 Metric Tons/Yr (10^6 Tons/Yr)							
	1970	1971	1972	1973	1974	1975	1976	1977
Transportation	80.5 (88.6)	81.1 (89.2)	85.4 (93.9)	85.9 (94.5)	81.7 (89.9)	82.0 (90.2)	85.1 (93.6)	85.7 (94.3)
Highway Vehicles	70.9 (78.0)	71.7 (78.9)	76.1 (83.7)	76.5 (84.2)	73.3 (80.6)	73.8 (81.2)	76.6 (84.3)	77.2 (84.7)
Non-Highway Vehicles	9.6 (10.6)	9.4 (10.3)	9.3 (10.2)	9.4 (10.3)	8.4 (9.3)	8.2 (9.0)	8.5 (9.3)	8.5 (9.3)
Stationary Fuel Combustion	1.3 (1.43)	1.4 (1.54)	1.3 (1.43)	1.4 (1.54)	1.3 (1.43)	1.1 (1.21)	1.2 (1.32)	1.2 (1.32)
Electric Utilities	0.2 (0.22)	0.2 (0.22)	0.2 (0.22)	0.3 (0.33)	0.3 (0.33)	0.3 (0.33)	0.3 (0.33)	0.3 (0.33)
Industrial	0.6 (0.66)	0.6 (0.66)	0.6 (0.66)	0.6 (0.66)	0.6 (0.66)	0.5 (0.55)	0.6 (0.66)	0.6 (0.66)
Residential, Commercial, Institutional	0.5 (0.55)	0.6 (0.66)	0.5 (0.55)	0.5 (0.55)	0.4 (0.44)	0.3 (0.33)	0.3 (0.33)	0.3 (0.33)
Industrial Processes	8.0 (8.8)	7.9 (8.7)	7.9 (8.7)	8.2 (9.0)	8.2 (9.0)	7.3 (8.0)	7.8 (8.6)	8.3 (9.1)
Chemicals	2.9 (3.2)	2.7 (3.0)	2.5 (2.7)	2.7 (3.0)	2.5 (2.7)	2.2 (2.4)	2.4 (2.65)	2.8 (3.1)
Petroleum Refining	2.1 (2.3)	2.1 (2.3)	2.2 (2.4)	2.2 (2.4)	2.3 (2.5)	2.4 (2.6)	2.4 (2.65)	2.4 (2.6)
Metals	2.1 (2.3)	2.2 (2.4)	2.3 (2.5)	2.3 (2.5)	2.4 (2.6)	1.8 (2.0)	1.9 (2.1)	2.0 (2.2)
Pulp and Paper	0.9 (1.0)	0.9 (1.0)	1.0 (1.1)	1.0 (1.1)	1.0 (1.1)	0.9 (1.0)	1.1 (1.2)	1.1 (1.2)
Solid Waste Incineration	6.2 (6.8)	4.7 (5.2)	4.0 (4.4)	3.6 (4.0)	3.2 (3.5)	2.9 (3.2)	2.9 (3.2)	2.6 (2.9)
Miscellaneous	6.2 (6.82)	7.4 (8.14)	5.2 (5.72)	4.4 (4.84)	5.3 (5.83)	3.6 (3.96)	5.9 (6.49)	4.9 (5.39)
Forest Wildfires and Managed Burning	4.3 (4.73)	5.9 (6.49)	4.2 (4.62)	3.5 (3.85)	4.5 (4.95)	3.0 (3.30)	5.3 (5.83)	4.3 (4.73)
Agricultural Burning	1.5 (1.65)	1.2 (1.32)	0.8 (0.88)	0.7 (0.77)	0.6 (0.66)	0.5 (0.55)	0.5 (0.55)	0.5 (0.55)
Coal Refuse Pile Burning	0.3 (0.33)	0.2 (0.22)	0.1 (0.11)	0.1 (0.11)	0.1 (0.11)	0	0	0
Structural Fires	0.1 (0.11)	0.1 (0.11)	0.1 (0.11)	0.1 (0.11)	0.1 (0.11)	0.1 (0.11)	0.1 (0.11)	0.1 (0.11)
TOTAL	102.2 (112.4)	102.5 (112.8)	103.8 (114.2)	103.5 (113.9)	99.7 (109.7)	96.9 (106.6)	102.9 (113.2)	102.7 (113.0)

Source: Reference 4

vehicles have increased about 6.4 percent from 1970 to 1977. Emission estimates for other source categories have remained relatively stable.

Projections

Future nationwide CO emissions from stationary sources will depend in large measure upon future Federal, State, and local air regulatory action. Since this document and concurrent air quality criteria documents will provide an important basis for determining regulatory action, it is not possible to make meaningful predictions of future nationwide CO emissions from stationary sources. The Clean Air Act, as amended in 1977, specifies a course of action for future control of CO emissions from mobile sources. The effect of the Act on future emissions from mobile sources is discussed in Chapter 3.

2.5 SAMPLING AND ANALYTICAL METHODS

Detailed information is available in the open literature on sampling and analysis of carbon monoxide emissions. The following is a brief review of the subject. Three categories of carbon monoxide monitoring are addressed: (1) stationary source emissions, (2) mobile source emissions, and (3) ambient air.

Two general methods of sample collection may be used for these monitoring categories, grab (instantaneous) sampling and integrated (continuous) sampling. The choice of collection method must be coordinated with the analytical method which will be used to determine carbon monoxide content. Grab samples for carbon monoxide measurement are typically taken using an apparatus such as that shown in Figure 2-2. A certain quantity of gas is pumped into a sample bag over a short time interval. This represents an instantaneous sample of the gas. A more representative grab sample may be obtained by taking several such samples over several intervals and combining them. An integrated or continuous sample can be taken using a sampling train similar to the one shown in Figure 2-3. This is the EPA sampling train which incorporates a gas conditioning section to remove moisture and carbon dioxide.[6] This conditioning minimizes interferences with the analytical method. The EPA analytical method for carbon monoxide is the non-dispersive infrared (NDIR) analysis method.[7]

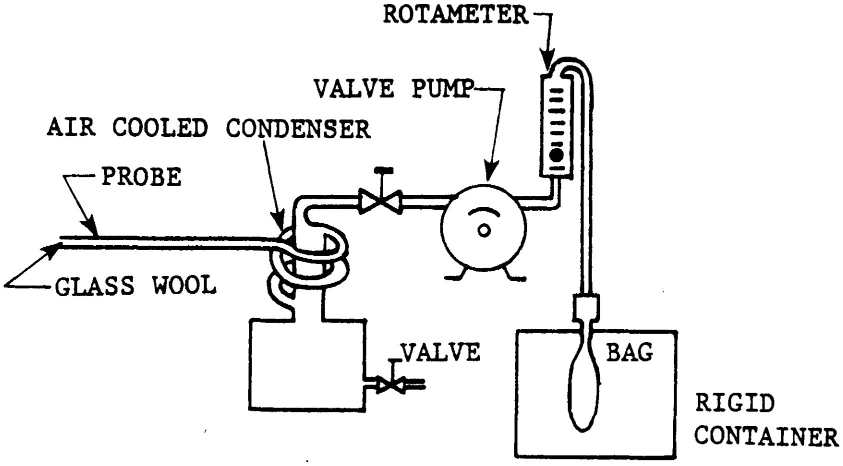

Figure 2-2. Grab Sampling System for CO Collection

Analytical methods currently used to determine the quantity of carbon monoxide present in a sample of gas are either instrumental methods or wet chemical methods. Instrumental methods include non-dispersive infrared (NDIR) and gas chromatographic analysis.

NDIR analysis, the EPA reference method, has been used to obtain most of the available air quality data for carbon monoxide.[7] This instrument relies on the principle of selective absorption of infrared radiation by carbon monoxide. Infrared radiation is passed through two parallel cells, a sample cell containing the gas to be analyzed, and a reference cell. The net radiation passing through the two cells is then passed into carbon monoxide detectors. Carbon monoxide present in the sample cell absorbs some of the infrared radiation, reducing the amount of radiation reaching the detector cell. The detector cell senses the difference in temperature and pressure between the sample detector cell and the reference detector cell and produces a signal corresponding to the concentration of carbon monoxide in the sample gas. This system is shown in Figure 2-4. The NDIR instruments have a typical minimum sensitivity of 20 ppm for carbon monoxide.

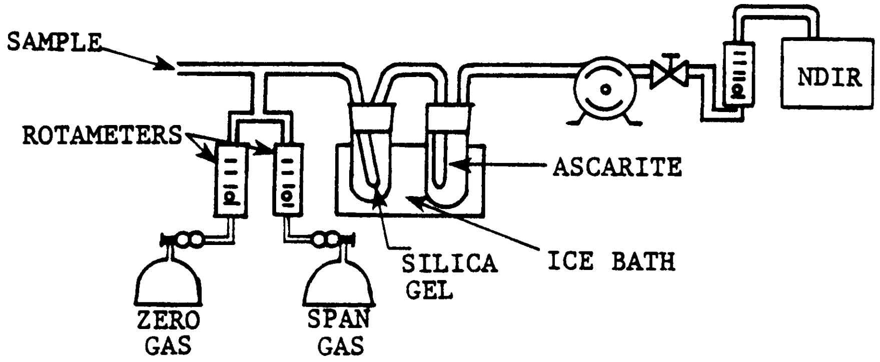

Figure 2-3. EPA Integrated Sampling Train for Carbon Monoxide

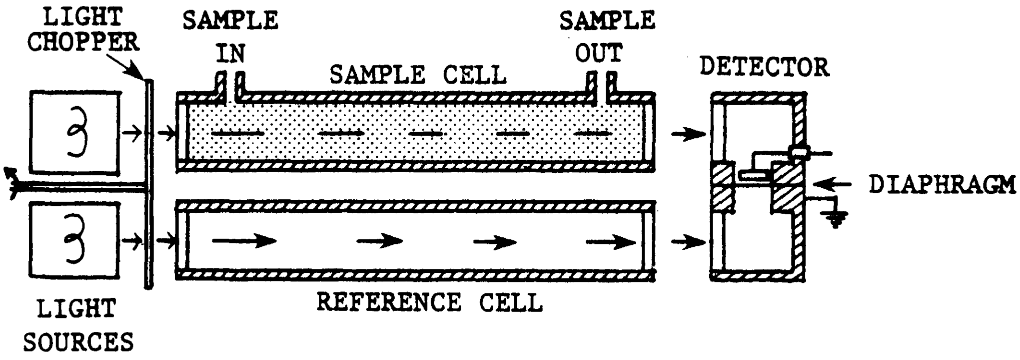

Figure 2-4. Nondispersive Infrared Gas Analyzer

Gas chromatographic analysis offers greater sensitivity than the NDIR method, with measurement capabilities down to 0.05 ppm.[7] This method involves separation of carbon monoxide from methane using a molecular sieve. The carbon monoxide is then quantitatively converted to methane (typically using hydrogen gas over a nickel catalyst), and analyzed using a flame ionization detector (FID). Other advantages over the NDIR method are that the response to carbon monoxide is linear over the entire concentration range and the method is specific to carbon monoxide.

Wet chemical analytical methods for carbon monoxide analysis depend upon one of three classes of reactions: (1) reduction of a metal, (2) catalytic oxidation to carbon dioxide, or (3) complexation.[8] The reduction method is attractive because of its simplicity although it is limited by the low solubility of carbon monoxide in aqueous solutions and the long reaction time required for completion of the reduction reaction. These factors limit the use of this analytical method to grab samples. This method is used as the basis for carbon monoxide detector tubes. These tubes typically contain silica gel impregnated with reagents which undergo a chemical change upon reaction with carbon monoxide.

The oxidation methods of carbon monoxide analysis rely upon catalytic oxidation to carbon dioxide.[8] Two methods of analysis can be used, one which determines the quantity of carbon dioxide produced; the other determines the quantity of species reduced by reaction with carbon monoxide. Each of these methods requires certain species to be removed to minimize interferences. The major advantage of the oxidation method is that a continuous integrated sample is used, insuring a more representative sample than a grab sample. The drawbacks include the necessity of a complex sampling train to condition the sample gas or to remove possible interferences.

Complexation methods for certain carbon monoxide analysis rely on two techniques, volumetric analysis, through absorption, or blood methods relying on the carbon monoxide--hemoglobin complex.[8] The absorption method most widely used is the Orsat analysis, which gives gas concentrations on a dry basis. Orsat analysis relies upon an apparatus which exposes a known quantity of gas to reagents which absorb oxygen, carbon dioxide, and carbon monoxide. The volumetric change resulting from the absorption of these species is read on a scale typically graduated in 0.2 percent increments which can be read with reasonable accuracy to 0.1 percent.[9,10] All of the above methods lack the sensitivity necessary to measure low levels of carbon monoxide, i.e., below 100 ppm. They are also limited to use on grab samples.

The type of sampling technique and analytical method used for carbon monoxide determination depends upon the category of monitoring being performed, i.e., stationary sources, mobile source, or ambient, and the reason for monitoring, i.e., compliance, background level determination, etc.

For stationary source monitoring, the NDIR method utilizing an integrated sampling train is the EPA reference method.[7] Gas chromatographic analysis may also be performed on an integrated sample with better sensitivity than NDIR. Grab samples may also be taken and analyzed by reduction or complexation wet chemical methods, or either instrumental method.

For mobile source monitoring, i.e., exhaust gases from vehicles, NDIR methods are primarily used for carbon monoxide analysis.[7] The samples may be either grab samples or integrated samples. Gas chromatography may also be used with either sampling technique.

For ambient monitoring, the use of gas chromatographic analysis offers greater sensitivity which is important if low levels of carbon monoxide are expected.[7]

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3. MOBILE SOURCE CONTROL

Estimates of 1977 nationwide emissions from mobile sources are given in Tables 2-3, 2-4, and 2-5. As these tables show, about 83 percent of all nationwide emissions are from transportation sources. About 90 percent of the CO emissions from transportation sources are from motor vehicles. Table 2-10 shows that CO emissions from transportation sources have increased from 80.5×10^6 metric tons (88.6×10^6 tons) in 1970 to 85.7×10^6 metric tons (94.3×10^6 tons) in 1977.[1]

The relationship between CO emissions and air/fuel ratio is shown in Figure 3-1. A simplified description of CO and CO_2 production during the combustion process is shown in the following steps:

$$2C + O_2 \rightarrow 2CO$$

$$2CO + O_2 \rightarrow 2CO_2$$

The first reaction proceeds at a much greater rate than the second. Hydrogen in the fuel is oxidized to H_2O quite easily, provided sufficient oxygen and heat is available locally for combustion. Hydrocarbons (HC) present in the fuel are also typically oxidized faster to CO than to CO_2. Poor distribution and mixing of fuel and air (which is more likely when

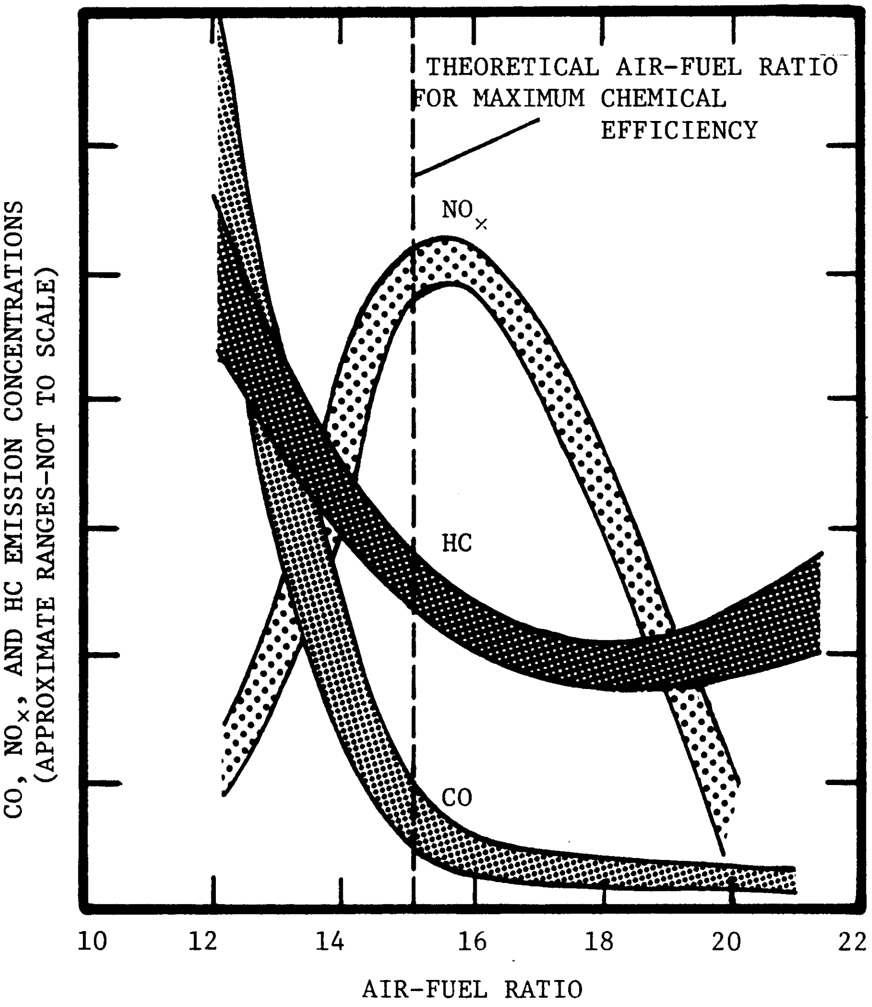

FIGURE 3-1. RELATIONSHIPS OF CO, NO_x, AND HC EMISSION CONCENTRATIONS AND AIR-FUEL RATIO

fuel droplets rather than fuel vapors are present) can result in incomplete combustion, and also produce CO that is emitted in the exhaust gas.

Either a chemically correct air/fuel mixture (stoichiometric) or an excess of air provides CO control. When the air/fuel ratio is richer than chemically correct, substantial amounts of CO appear in the exhaust. When the mixture is chemically correct or leaner than stoichiometric, CO concentration usually does not drop to zero. This happens because of a combination of cycle-to-cycle and/or cylinder-to-cylinder air/fuel charge maldistribution and slow CO reaction kinetics. Fuel injection, better carburetion or better overall fuel distribution are approaches to low CO emission from the engine. When a hydrocarbon fuel is burned with an amount of air containing enough oxygen to oxidize it completely, the following basic chemical reaction is assumed to occur:[2]

$$1.00\ CH_{1.85} + 1.46\ O_2 + 5.50\ N_2 \rightarrow$$

$$0.925\ H_2O + 1.00\ CO_2 + 5.50\ N_2$$

This chemical reaction assumes: 1) hydrocarbon fuels are accurately represented and contain an average of 1.85 hydrogen atoms for each carbon atom; 2) the volume ratio of nitrogen to oxygen in the air is 3.76:1; 3) the fuel is burned completely to water and carbon dioxide; and 4) nitrogen is inert and does not react with any other substances in the combustion chamber. Assumptions 1 and 2 are quite true in practice, but the formation of HC, CO and NOx in the combustion process indicates that assumptions 3 and 4 are not wholly correct.

Although the overall mixture is stoichiometric, local conditions at any particular point in the combustion chamber may be far from stoichiometric. An air-rich mixture (high air/fuel ratio) would provide excess air to partially offset the increased CO emissions that result from poor distribution and vaporization. A relatively large excess of air is normally found in stratified charge engines, diesel engines, gas turbine engines, and some turbocharged gasoline engines. This accounts for the relatively low CO emissions which can be found from these types of powerplants. Another factor that may contribute to increased emissions is flame quenching at the relatively cool combustion chamber boundaries. Quenching can occur even if the fuel is perfectly vaporized and distributed throughout the combustion chamber. Gross malfunction of the ignition or fuel induction systems can increase CO and HC emissions from spark-ignition engines. A misfire, for example, allows an entire air/fuel charge to be emitted into the exhaust system. A sticking automatic choke system, or a restriction in the air intake system can also have an adverse effect on the air/fuel ratio, generally increasing both CO and HC emissions.

3.1 BACKGROUND - ENGINE DESIGN VARIABLES

It is often impossible to isolate the effect of any single design variable or operating parameter on engine emissions. Some of these factors for spark-ignition engines are included as follows:[3]

1) air-fuel ratio
2) load or power level
3) speed

4) spark/injection timing
5) exhaust backpressure
6) valve overlap
7) intake manifold pressure
8) combustion chamber deposit build-up
9) surface temperature
10) surface to volume ratio
11) combustion chamber design
12) stroke to bore ratio
13) displacement per cylinder
14) compression ratio

In the following discussion of these design variables, HC and CO are treated together because, once formed, both can be influenced by chemical oxidation in either the cylinder or exhaust system if excess oxygen is present. The importance of a lean air/fuel ratio for CO reduction is obvious, and the gain in emission reduction by operating vehicles lean suggests the importance of minimum carburetor/fuel injection tolerances and good manufacturing control to achieve uniform fuel distribution. Significant after-reaction can occur in the exhaust system with lean overall air/fuel ratios or with air injection when the average exhaust temperature exceeds 650°C (1200°F) but after-reaction might not continue to lower emissions as the mixture becomes even leaner because the exhaust temperature can become too low to achieve a significant reaction rate.

At a fixed air/fuel ratio there is no effect of power output on carbon monoxide emission concentration. However, the mass emission of CO will increase directly with increasing power output and air consumption. Therefore, a smaller, lighter vehicle may have the advantage of lower CO mass emission due to its reduced power demand to drive the cycle, all other things being equal. However, all other things are generally not equal, especially when the standards are based on mass.

Increased exhaust port turbulence at higher engine speeds promotes exhaust system oxidation reactions through better mixing. This promotes after-oxidation of the quenched layer and one would expect mass emissions of HC to decrease with an increase in speed; however, the decrease will be less than expected because of the increased flow volume required to overcome higher engine friction at higher speeds. Speed has no effect, however, on CO concentration because oxidation of CO in the exhaust is kinetically limited rather than mixing limited at the normal exhaust temperatures.

Spark retard has little effect on CO concentration except at very retarded timing where the lack of time to complete CO oxidation leads to increased CO emissions. In actual operation increased throttle is required to maintain constant power levels and thus the mass of CO emitted from the cylinder tends to increase. The increase is off-set to some extent by the higher exhaust temperatures which result in some CO clean-up in the exhaust system.

Increasing backpressure increases the amount of residual exhaust gas left in the cylinder at the end of the exhaust cycle. If this increase in residual does not increase the percentage of dilution of the fresh charge to a level where the combustion is adversely affected, the HC and probably the CO emissions will be lowered. The reduction arises from leaving the tail end of the exhaust in the cylinder and subsequently oxidizing it in the next cycle. At idle, dilution is already high and combustion is usually marginal so the engine cannot tolerate much more exhaust dilution.

Increasing valve overlap has a similar effect to increasing the backpressure. The charge is further diluted with residual gases. Deterioration in combustion can result with lean mixtures as the residual is greater with increased valve overlap. If the mixture ratio must be enriched to provide stable idle and off-idle performance, then CO emissions will be increased. There is no effect on carbon monoxide concentration at a constant mixture ratio, but any increase in throttle opening to overcome the increased charge dilution will increase the CO as well as the HC emissions.

Intake manifold pressure is essentially an indicator of engine power. Since carburetor and distributor settings are variable in the vehicle, there is a change in emission concentration as the throttle is varied at constant speed. In the intermediate power range, at constant speed, minimum HC and CO from the engine are achievable for lean air-fuel calibrations. At wide open throttle, the power valve is normally actuated and the mixture is enriched. The resulting enrichment forces an increase in HC and CO emissions, but the increase is limited somewhat by exhaust cleanup arising from increased exhaust temperatures. At light loads and low manifold pressure, increased emissions result from increased wall quenching accompanying the rich mixtures as well as incomplete flame propagation. Dash-pots or other throttle cracking devices are often used to limit intake manifold vacuum during deceleration. Another approach is to include a fuel shut-off device, commonly used with fuel injection systems, to minimize emissions during the deceleration mode.

Combustion chamber deposit buildup acts to increase the surface area of the combustion chamber because of the resulting irregular, porous surface deposits. Deposits also act as a sponge to trap raw fuel which remains unburned and thus adds to the exhaust HC. In addition, exhaust deposits tend to increase compression ratio which also increases HC emission. There is a negligible effect of deposit build-up in the combustion chamber on CO emission.

Surface temperature changes the thickness of the combustion chamber quench layer and the degree of after-reaction. Increased surface temperature decreases HC emissions by increasing fuel evaporation and distribution, combustion chamber temperature, exhaust system temperature, and therefore, exhaust gas reaction. However, an increase in surface temperature by engine modification is expected to have an adverse effect on engine octane requirement, volumetric efficiency and lubrication. Hydrocarbon emissions arise primarily from quenching at the combustion wall surface.

The ratio of surface area to volume in the combustion chamber is useful for interpreting the effects of many design and operating variables on HC emission concentration. CO emission concentration, however, is not necessarily affected by surface-to-volume ratio changes.

The combustion chamber design is an important consideration to reduce the surface area for a given clearance volume. For example, a 10 centimeter (4 inch) bore engine maintaining a fixed clearance volume, can have surface-to-volume ratios of 8.0:1 for the pot-in-piston design, 7.2:1 for the pancake design, 6.6:1 for the hemisphere in head design, and 6.4:1 for the double-hemisphere design. The stroke-to-bore ratio is another design factor used to minimize the surface-to-volume ratio by increasing the stroke-to-bore ratio. Unfortunately, this modification is opposed to modern engine design practice which favors short strokes for lower friction and lower engine silhouette.

Larger displacement per cylinder suggests the possibility that for the same displacement, engine emissions can be reduced by decreasing the number of cylinders but increasing the displacement per cylinder. On the other hand, for a given number of cylinders, increasing engine displacement can reduce the surface-to-volume ratio, but mass emissions might increase because of increased engine friction and intake charge volume.

A large reduction in compression ratio can also significantly reduce the surface-to-volume ratio. This increases the clearance volume with little increase in surface area. However, reducing the compression ratio results in lower thermal efficiency and reduced engine power. Some of the major causes of high CO emission are the direct result of improper maintenance for any specific engine design combination which results in maladjusted carburetors, air/fuel mixture imbalances and general malfunction of emission control devices.

3.2 DESCRIPTION OF LIGHT DUTY VEHICLE, LIGHT DUTY TRUCK, AND HEAVY DUTY TRUCK INDUSTRY

A light duty vehicle (LDV) is currently defined as a passenger car or passenger car derivative capable of seating 12 passengers or less.[4]

A light duty truck (LDT) is any motor vehicle rated at 3856 kg (8,500 lb.) gross vehicle weight rating (GVWR) or less and under 2720 kg (6,000 lb.) vehicle curb weight, has a basic vehicle frontal area of 4.27 m^2 (46 ft^2) or less, and which is: a) designed primarily for purposes of transportation of property or is a derivative of such a vehicle, or b) designed primarily for transportation of persons having a capacity of more than 12 persons, or c) available with special features enabling off-street or off-highway operation and use.[4]

A heavy duty vehicle (HDV) is defined as any motor vehicle that has a vehicle curb weight of more than 2720 kg (6000 lb.) or that is rated at more than 3856 kg (8500 lb.) GVWR, or that has a basic vehicle frontal area in excess of 4.27 m^2 (46 ft^2).[4]

U.S. manufacture of light duty vehicles is almost entirely done by the five major motor vehicle manufacturers: General Motors Corp., Ford Motor Company, Chrysler Corp., Volkswagen, and American Motors Corp. In 1977 factory sales of passenger cars exceeded 10.4 million of which 9.2 million were of domestic origin.[5] The major foreign importers were Toyota, Nissan, Volkswagen, Honda and Fiat.

The manufacture of light duty trucks sold in the U.S. is primarily accomplished by the major domestic passenger car producers. General Motors Corporation (Chevrolet and GMC divisions), Ford Motor Company and Chrysler Corporation (Dodge Truck division) all have separate truck divisions which produce light duty as well as heavy duty trucks. American Motors Corporation operates the Jeep division which manufactures light duty trucks.

The other major domestic manufacturer of LDT's is the International Harvester Corporation (IHC). International does not produce light duty passenger vehicles but does produce a line of light and heavy duty trucks.

Some LDT's sold in the U.S. are imported. The majority of U.S. imports of trucks come from the Canadian plants operated by U.S. domestic producers. Some imports, primarily light pick-up trucks, under 1814 kg (4,000 lb.) GVWR, come from Japanese producers. The major importers are Nissan (Datsun), Toyota, Isuzu, and Toyo Kogyo.

Table 3-1 shows unit factory sales for light duty vehicles, light duty trucks, and heavy duty vehicles from U.S. plants. Most data available on light duty trucks are presented in two categories, based on GVWR. There is a 0-2722 kg (0-6,000 lb.) and a 2722-4536 kg (6,001-10,000 lb.) category. Since the new definition of light duty trucks includes only trucks up to 3856 kg (8,500 lb.) GVWR, some adjustment to the 2722-4536 kg (6,001-10,000 lb.) category was necessary for this analysis. The 1975 industry production data available to EPA indicate that only five percent of all trucks with

TABLE 3-1

LIGHT DUTY VEHICLE, LIGHT DUTY TRUCK AND HEAVY DUTY VEHICLE FACTORY SALES FROM U.S. PLANTS

Type of Vehicle	1978	1977	1976	1975	1974	1973	1972	1971	1970	1969
Light Duty Vehicle	9,165,190	9,213,654	8,497,603	6,712,852	7,331,946	9,657,647	8,823,938	8,584,592	6,546,817	8,223,715
Light Duty Truck redefined class 0-3,856 kg GVWR* (0-8,500 lb)	3,099,966	2,896,329	2,505,448	1,848,223	2,154,892	2,372,269	1,899,204	1,598,785	1,284,241	1,450,011
Heavy Duty Vehicle > 3,856 kg GVWR (8,500 lb)										
Gasoline	420,170	381,975	346,041	321,430	405,162	439,030	405,514	341,294	302,900	358,751
Diesel	186,103	162,031	127,560	102,507	167,259	168,389	143,089	113,067	105,289	114,417
LDV, LDT and HDV	12,871,429	12,653,989	11,476,652	8,985,012	10,059,259	12,637,335	11,270,745	10,637,738	8,239,257	10,146,894

*Adjusted to 95 percent at 0-4,536 kg (0-10,000 lb) GVWR

Source: MVMA, Communications Division

GVWR's less than 4536 kg (10,000 lb.) have GVWR's of more than 3856 kg (8,500 lb.). This five percent figure is used in Table 3-1 to adjust production data to fit the LDT definition.

Heavy Duty Vehicles only represent on the order of 5 to 6 percent of the total annual U.S. motor vehicle factory sales, but 70-75% of these vehicles are powered by gasoline engines, most of which are derivatives of their LDV engine counterparts. The majority of these gasoline powered trucks are used in GVWR classes less than 14969 kg (33,000 lb.) GVWR and the majority of trucks rated greater than 14969 Kg (33,000 lb.) GVWR are powered by diesel engines. The total population of motor vehicles in these categories is presented in Table 3-2.

Table 3-3 presents data on the number of passenger cars and trucks in use by age. This information, when compared to past carbon monoxide standards, can give an indication of the number of vehicles in the United States subject to a given standard. This is important since the air quality goal of a control program based on exhaust emission standards will not be achieved until most vehicles are equipped with controls that can meet the standards. The data from Table 3-3 indicates that there are approximately 23% of the passenger cars in-use which are uncontrolled. Approximately 42% of the trucks in-use are uncontrolled.

TABLE 3-2

NEW VEHICLE REGISTRATIONS

Source	New Vehicle Registrations	
	1976	1977
LDV	9,751,485	10,751,924
LDT AND HDV	3,058,009	3,465,193
Total	12,809,494	14,217,117

Source	Total Vehicle Registrations	
	1976	1977
LDV	110,351,327	114,113,000
LDT and HDV	27,719,597	29,230,000
Total	138,070,924	143,343,000

Excludes the State of Oklahoma

Source: Reference 5

TABLE 3-3

MOTOR VEHICLES IN USE BY AGE
AS OF JULY 1, 1977

Age in Years	Passenger Cars (1000's)	Trucks (1000's)
Under 1	7,177	2,177
1 - 2	9,557	2,746
2 - 3	7,477	2,109
3 - 4	9,594	2,689
4 - 5	10,854	2,752
5 - 6	9,563	2,291
6 - 7	7,866	1,639
7 - 8	7,449	1,573
8 - 9	6,963	1,645
9 - 10	5,859	1,267
10 - 11	4,416	1,129
11 - 12	3,887	1,096
12 - 13	3,023	922
13 - 14	1,969	736
14 - 15	1,315	566
15 - 16	818	442
16 and older	2,093	2,422

Source: Reference 5

3.3 DESCRIPTION OF THE AIRCRAFT INDUSTRY

EPA has established the following classes of aircraft and corresponding power-plant classes to which different sets of standards would apply as determined by the technical, economic, and safety constraints which are relevant to each class:

Class	Type	Aircraft Application
P1	Piston Engines (excluding radials)	Light general aviation
P2	Turboprop engines	Medium to heavy general aviation; some commercial air transport
T1	Small turbojet/fan engines	General aviation jet aircraft; some commercial air transport
T2	Large turbojet/fan engines intended for subsonic flight	Commercial subsonic transport
T3,T4	Special classes applying to specific engines for the purpose of instituting early smoke standards	Commercial subsonic transports
T5	Large turbojet/fan engines intended for supersonic flight	Supersonic transport
APU	Gas turbine auxiliary power units	Many turbojet/turboprop

The emissions levels permitted by the standards are described by an EPA parameter (EPAP) which is defined in the aircraft regulations. Briefly, it is a measure of the total emission of a particular pollutant produced by an engine over a typical landing/takeoff (LTO) cycle normalized with respect to the total power output of the engine over that cycle. As such, larger engines performing greater useful work are permitted proportionally larger amounts of total emissions over smaller engines.

The standards, promulgated in July 1973 for all classes but T5 and in July 1976 for that class, are summarized in Table 3-4.[6]

In addition, there has been proposed (FR Vol. 38, N. 136, July 17, 1973, p. 19050) a regulation which, if promulgated, would require all (including those already in service as of January 1, 1979) large i.e., > 129 kilonewtons (29,000 lbs.) thrust in-use engines of the T2 class to comply with the T2 class standards of 1979 for HC, CO, NO_x, and smoke. As this would effectively require a retrofit program for the older engines (pre-1979), the compliance date was proposed to be January 1, 1983, thus allowing four years for that retrofit to be accomplished.

On a nationwide basis, however, all aircraft are estimated to contribute only 0.63 percent of the total CO as shown in Table 2-4. This includes commercial transport, military and general aviation. General aviation includes a wide variety of aircraft which are used for business, training, and pleasure flying. Commercial transport aircraft source CO is shown as a percentage of the total impact for different Air Quality Control Regions in Table 3-5. With the relatively small percentage of the total CO inventory attributable to aircraft sources, it is not meaningful or perhaps even possible within the accuracy of any existing air quality computer model to discuss the impact of aircraft source CO emissions from a nationwide

TABLE 3-4

SUMMARY OF AIRCRAFT ENGINE REGULATIONS

Newly Manufactured Engines

			EPAP[a]				
Class	HC		CO		NO$_x$		Compliance Date
T1	45.3	(1.6)	266	(9.4)	105	(3.7)	January 1, 1979
T2	22.7	(0.8)	122	(4.3)	85	(3.0)	January 1, 1979
T3	22.7	(0.8)	122	(4.3)	85	(3.0)	January 1, 1979
T4	22.7	(0.8)	122	(4.3)	85	(3.0)	January 1, 1979
T5	110.5	(3.9)	853	(30.1)	255	(9.0)	January 1, 1979
P2[b]	3.0	(4.9)	16.3	(26.8)	7.8	(12.9)	January 1, 1979
APU[b]	0.2	(0.4)	3.0	(5.0)	1.8	(3.0)	January 1, 1979

The standards for advanced engines are:

Newly Certified Engines

			EPAP[a]				
Class	HC		CO		NO$_x$		Compliance Date
T2	11.3	(0.4)	85	(3.0)	85	(3.0)	January 1, 1981
T5	28.3	(1.0)	221	(7.8)	142	(5.0)	January 1, 1984

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[a] Micrograms of pollutant per Newton thrust seconds (pounds of pollutant per 1000 pounds thrust hours) over the LTO except as noted.

[b] Grams of pollutant per kilowatt hour (pounds of pollutant per 1000 horsepower hours) over the LTO cycle.

Source: Reference 6

TABLE 3-5

COMMERCIAL AIRCRAFT SOURCE CO EMISSIONS AS A PERCENTAGE OF TOTAL AIR QUALITY CONTROL REGION EMISSIONS

AQCR	Percentage of AQCR Emissions Attributable to Commercial Aircraft
	CO
Los Angeles	0.22
San Francisco	0.37
NY-NJ-Conn.	0.32
Chicago	0.19
St. Louis	0.34
Cincinnati	0.14
Baltimore	0.32
Boston	0.35
Houston	0.32
S.E. Wisconsin	0.19
Washington, D.C.	0.46
Atlanta	1.08

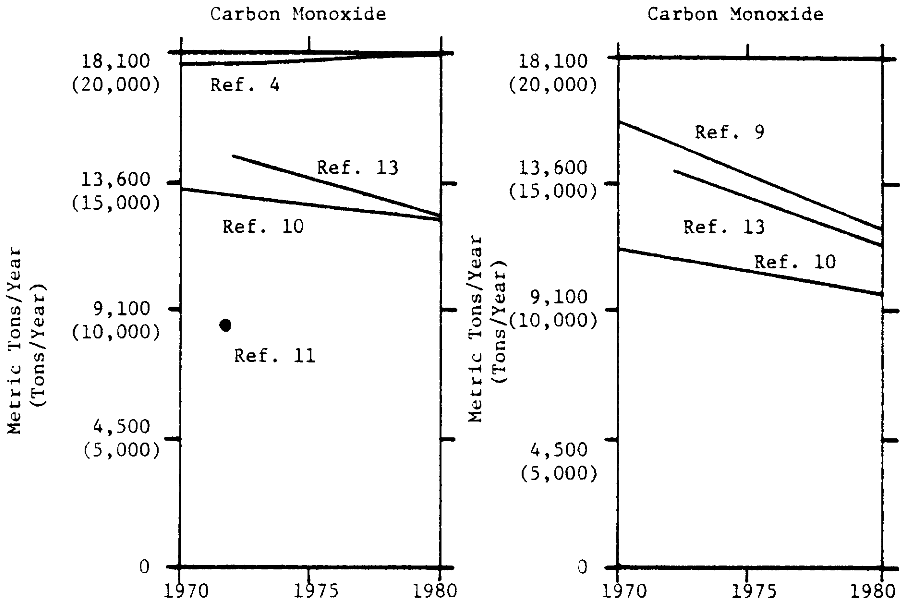
Source: Reference 7

standpoint.[8] EPA has monitored the progress of aircraft technology since 1973 and has reviewed the impact of various types of aircraft on ambient air quality. As a result, it is currently being proposed that aircraft emission standards for commercial turbine engines be relaxed and implementation be delayed considering the status of control technology and lead time considerations.[7]

CO violations attributable to aircraft are occurring, however, at some airport terminal boarding gate areas and at the end of the runways. These situations will require CO control technique strategies to preclude such point-source violations. A point-source violation is defined by EPA to be one with emissions of any pollutant greater than 100 tons/year.[7] By this definition, aircraft operating at the major commerical airports must be considered as a major source of CO as shown in Figure 3-2. Yet, as shown in Table 3-5, commercial aircraft contribute only 1.1 percent or less of the total CO in any particular air quality control region. The general conclusion is that the aircraft source for CO is significant even though the overall percentage contribution may be small. New data and models are currently being gathered and evaluated to determine if this conclusion is valid. For information on those special cases where aircraft source CO control measures are required, the reader is referred to Reference 6.

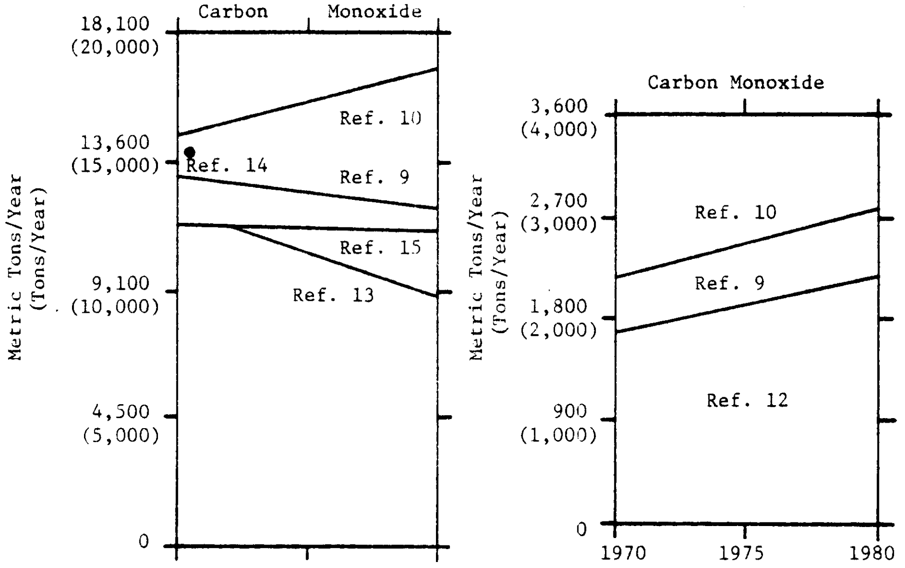
3.4 VEHICLE CO EMISSION STANDARDS

Motor vehicle emission standards on passenger cars and light duty trucks have been enforced in California since 1966 and the remaining states since 1968.[16] CO standards for medium- and heavy-duty trucks were implemented in



Comparison of Estimates of Aircraft Emissions at O'Hare. 1970-1980

Comparison of Estimates of Aircraft Emissions at J.F.K., 1970-1980



Comparison of Estimates of Aircraft Emissions at L.A. International, 1970-1980

Comparison of Estimates of Aircraft Emissions at Washington National, 1970-1980

Source: Reference 7

FIGURE 3-2. ESTIMATES OF AIRCRAFT SOURCE CO EMISSIONS AT MAJOR NATIONAL AIRPORTS

California in 1969 and for the 49 states in 1970. Table 3-6 summarizes the standards for CO exhaust emissions from non-California light-duty vehicles and light-duty trucks. Table 3-7 summarizes the California standards for light-duty vehicles, light-duty trucks, and medium-duty trucks. Other CO exhaust emission standards are presented in Tables 3-8, 3-9 and 3-10. These tables apply to non-California heavy-duty vehicles (HDV), California HDV's, and motorcylces, respectively. For detailed descriptions of testing procedures and methodologies, refer to the Special Bibliography at the end of this chapter.

3.5 IN-USE EXPERIENCE

Results from a 1973 surveillance program[17], the In-Use Compliance Program, indicated that seven classes of 1973 and 1974 model year vehicles were significantly exceeding the emission standards in use. Subsequently, it was found from the analysis of the Fiscal Year 1974 (FY74) Emission Factor Program (EFP) that 63 percent of the 1975 model year (MY) vehicles that were tested failed to meet the standards for one or more pollutants.[18] Of 587 1975 MY vehicles tested, 52 percent failed because of high CO levels only or in combination with other pollutants. The FY75 EFP results for 1976 MY vehicles were not statistically different from the 1975 MY vehicles tested in the 1974 EFP in terms of mean HC and CO emissions.[19] Another study, called the Restorative Maintenance Project was initiated to better evaluate why such a large percentage of vehicles had excessive emissions and to determine if normal emissions could be restored.[20]

TABLE 3-6

Federal Vehicle Exhaust Emission Standards for CO

Model Year	CO Standard	
Light Duty Vehicles		
Pre-1968	No standard	
1968 - 1969	[a]2.3% by volume for 820-1639 cc displacement (50-100 CID) [a]2.0% by volume for 1640-2294 cc displacement (100-140 CID) [a]1.5% by volume for >2294 cc displacement (>140 CID)	
1970 - 1971[b]	14.3 g/km	(23 g/mi)
1972[c]	24.2 g/km	(39 g/mi)
1973 - 1974[c]	24.2 g/km	(39 g/mi)
1975 - 1976[d]	9.3 g/km	(15 g/mi)
1977 - 1979[d]	9.3 g/km	(15 g/mi)
1980[d]	4.3 g/km	(7.0 g/mi)
1981 and later[d]	2.1 g/km	(3.4 g/mi)[e]
Light Duty Trucks		
Less than 2720 kg (6000 lb) GVWR		
Pre-1975	Same standard as automobiles	
1975 - 1978[d]	12.4 g/km	(20 g/mi)
1979 - 1982[d]	11.2 g/km	(18 g/mi)
1983[d]	to be determined	
2720-3856 kg (6001-8500 lb) GVWR		
pre-1979	Same standard as heavy duty gasoline vehicles (see Table 3-8)	
1979 - 1982[d]	11.2 g/km	(10 g/mi)
1983[d]	to be determined	

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[a] Emission standard varied with vehicle's volumetric displacement using 7-mode driving cycle test

[b] 7-mode Test Procedure

[c] CVS-72 Test Procedure

[d] CVS-75 Test Procedure

[e] A waiver of the 2.19 g/km (3.4 g/mi) CO standard is possible for 1981 and 1982 at a level not to exceed 4.35 g/km (7 g/mi).

Source: <u>Title 40 CFR</u>

TABLE 3-7

CALIFORNIA VEHICLE EXHAUST EMISSION STANDARDS FOR LIGHT DUTY VEHICLES

MODEL YEAR	CO STANDARD
Automobiles[a]	
1966 - 1967	1.5% by volume
1968 - 1969	Same as U.S. standard
1970 - 1971	14.3 g/km[c] (23 g/mi)
1972	14.3 g/km[c] or 24.2 g/km[d] (23 g/mi or 39 g/mi)
1973 - 1974	24.2 g/km[d] (39 g/mi)[d]
1975 - 1980	5.6 g/km[e] (9.0 g/mi)[e]
1981[b]	4.3 g/km[c] or 2.1 g/km[e] (7.0 g/mi[c] or 3.4 g/mi[e])
1982 and later	4.3 g/km[e] (7.0 g/mi)[e]
Light Duty Trucks	
Less than 1814 kg (4000 lb) GVWR and 1815-2722 kg (4001-6000 lb) GVWR	
Pre-1975	Same as automobiles
1975	12.4 g/km[e] (20 g/mi)
1976 - 1978	10.6 g/km[e] (17 g/mi)
1979 and later	5.6 g/km[e] (9.0 g/mi)
Medium Duty Trucks	
2723 - 3856 kg (6001 - 8500 lb) GVWR	
1969 - 1977	Same as Heavy Duty Standards
1978 - 1980	10.6 g/km[e] (17 g/mi)[e]
1981 and later	5.6 g/km[e] (9.0 g/mi)[e]

[a] Standard applies to passenger cars and light duty trucks through 1974. After 1975, standards apply only to passenger cars.

[b] 4.3 g/km (7.0 g/mi) CO and 0.43 g/km (0.7 g/mi) NO_x or 2.1 g/km (3.4 g/mi) CO and 0.62 g/km (1.0 g/mi) NO_x [0.93 g/km (1.5 g/mi) NO_x optional with 161,000 km (100,000 mile) durability]

[c] 7-mode test procedure

[d] CVS-72

[e] CVS-75

Source: Title 13, California Administrative Code

TABLE 3-8

FEDERAL VEHICLE EXHAUST EMISSION STANDARDS FOR CO: HEAVY DUTY GASOLINE AND DIESEL VEHICLES

Model Year	CO Standard
Pre-1970[a]	No standard
1970 - 1973[a]	1.5% by volume
1974 - 1978	53.6 g/kw hr (40 g/BHP-hr)[b]
1979 - 1982	33.5 g/kw hr (25 g/BHP-hr)[b]
1983 and later	New standard and test procedure being developed

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[a] Gasoline Only

[b] Brake horsepower-hour

Source: Title 40 CFR

TABLE 3-9

CALIFORNIA VEHICLE EXHAUST EMISSION STANDARD FOR CO: HEAVY-DUTY GASOLINE AND DIESEL VEHICLES

Model Year	CO Standard
1969 - 1971[a]	1.5% by volume
1972	1.0% by volume
1973 - 1974	53.6 g/kw-hr (40 g/BHP-hr)
1975 - 1976	40.2 g/kw hr (30 g/BHP-hr)
1977 and later	33.5 g/kw hr (25 g/BHP-hr)

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[a] From 1969 - 1972, standards apply to gasoline-powered vehicles only. After 1973, standards apply both to gasoline- and diesel-powered vehicles.

Source: Title 13, California Administrative Code

TABLE 3-10

U.S. VEHICLE EXHAUST EMISSION STANDARDS FOR MOTORCYCLES - 50 STATES

Model Year	CO Standard
Pre-1978	No standard
1978 - 1979	17 g/km (27.4 g/mi)
1980 and later	12 g/km (19.3 g/mi)

Source: Title 40 CFR

TABLE 3-11

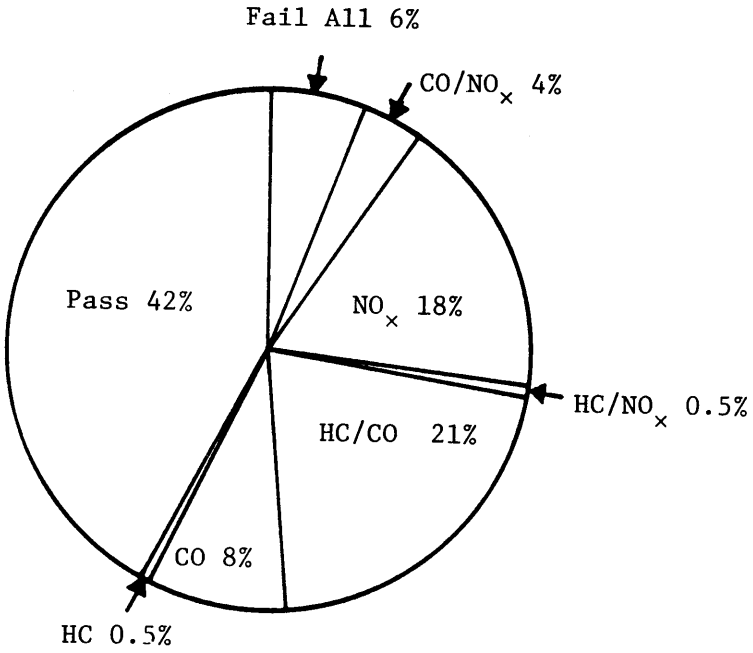
COMPARISON OF EXHAUST EMISSION LEVELS BETWEEN THE 49-STATE, LOW-ALTITUDE VEHICLES IN THE RESTORATIVE MAINTENANCE AND EMISSION FACTORS PROGRAMS

Model Year	Program	N	Average Mileage	HC g/km (g/mi)	CO g/km (g/mi)	NO_x g/km (g/mi)	% Meeting Standards
1975/1976	RM	300	12,900 km (8,000 mi)	0.81 (1.3)	12.6 (20.3)	1.74 (2.8)	42
1976	EF	515	18,500 km (11,500 mi)	0.81 (1.3)	11.4 (18.3)	1.62 (2.6)	45
1975	EF	587	14,200 km (8,800 mi)	0.81 (1.3)	14.2 (22.9)	1.49 (2.4)	37
1975/1976 Federal Standards	-	-		0.93 (1.5)	9.3 (15)	1.93 (3.1)	-

Source: Reference 20

A summary of exhaust emission results from the initial test on the 300 vehicles of the 1975 and 1976 model years in Chicago, Detroit, and Washington, D.C. is shown in Table 3-11.[20] These values are compared to the performance of 1975 and 1976 models tested in the Emission Factor programs as well as to 1975/1976 Federal Standards.

Table 3-11 indicates that this sample of Restorative Maintenance vehicles is similar to the Emission Factors fleet in terms of the initial test with regard to emission levels and pass/fail performance. Although the average levels of HC and NO_x are below the standards, the scatter of the individual data points combined with an average value of CO which was above the standard, allowed only 42 percent of the total fleet to meet the standards. (Figure 3-3.) The inspection which followed the initial test sequence revealed that 74 percent of the 1975 and 1976 models which failed to meet the standards had some form of malperformance in their emission control systems. Although few actual defects were discovered, many maladjustments and disablements were found. The primary area of malperformance was in the Carburetor/Choke/Exhaust Heat Control Valve System with a 66 percent failure rate over the entire sample. Limiter caps were missing or broken on 45 percent of the 300 vehicles; idle speed was maladjusted (more than ± 100 rpm from specification) on 25 percent and the choke adjustment was out of production tolerances on 10 percent of the vehicles tested. The ignition system was the second largest area for malperformance with a 27 percent overall rate. Most of this was basic ignition timing maladjustment at 19 percent. The remaining major area was the exhaust gas recirculation (EGR) system.



Source: Reference 20

FIGURE 3-3. PASS/FAIL OUTCOMES OF THE INITIAL TEST ON 1975 AND 1976 VEHICLES

Fifteen percent of the vehicles were found to have malperformance in this area. In testing 1977 models, fewer vehicles (58 percent) were found to have malperforming systems although the pattern discovered on the older vehicles was still present.

In general, the effect of engine component operation on CO and HC emissions is shown in Table 3-12. The effect on HC emissions is included here since CO formation is an intermediate product of combustion of hydrocarbon fuels.

3.6 CO EMISSION FACTORS

EPA has administered programs to determine how well vehicles perform in actual use by administering a series of exhaust emission surveillance programs. Test fleets of consumer-owned vehicles within various major cities are selected by model year, make, engine size, transmission and carburetor/fuel injection system in such proportion as to be representative of both the normal production of each model year and the contribution of that model year to total vehicle miles traveled. In the case of heavy duty vehicles, fuel type and gross vehicle weight are key items in the stratification scheme. The data collected in these programs are analyzed to provide an estimate of mean emissions with accumulation of age, percentage of vehicles complying with standards, and to assess the effect on emissions of vehicle parameters (engine displacement, vehicle weight, etc.).

These surveillance data, along with prototype vehicle test data, assembly line test data, and technical judgement form the basis for the existing and projected mobile source emission factors presented here.[22] For localized

TABLE 3-12

EFFECT OF ENGINE COMPONENT OPERATION ON EMISSIONS

	CHANGE IN EMISSIONS	
COMPONENT	Carbon Monoxide	Hydrocarbon
Decreased air-fuel ratio	Increase	Increase
Decreased engine idle speed	Increase	Increase
Restricted PCV valve	Increase	Increase
Restricted air filter	Increase	Increase
Choke malfunctions	Increase	Increase
Carburetor malfunctions	Large Increase	Increase
Ignition system malfunctions	NSC	Large Increase
Advanced spark timing	NSC	Increase
Stuck heat riser valve	Increase	NSC
Exhaust valve leak	NSC	Increase
Intake manifold leaks	Increase	Increase
Emission control device malfunction	Increase	Increase
Catalytic converter malfunction	Large Increase	Large Increase

NSC = No Significant Change

Source: Reference 21

pollutants such as CO, the ability of the test procedure to predict changes in emissions depends on the similarity of the localized driving pattern and associated operating conditions to those in the test procedure. The EPA, therefore, has developed a series of correction factors to expand upon the LDV and HDV test procedures and to predict emissions from a large number of user-specific scenarios. These are contained in Reference 22. Data required to develop these correction factors have been generated using statistical studies with consumer-owned vehicles.

The base CO exhaust and idle emission factors for LDV's, LDT's, MDT's, and HDV's and motorcycles are shown in Tables 3-13 through 3-22 and represent the mean emission factors for July of any particular calendar year. The emissions testing for light-duty vehicles, light-duty trucks and medium-duty trucks is performed according to the 1975 Federal Test Procedure (FTP) as stipulated in the Federal Register (Vol. 137, No. 211, November 15, 1972). Light-duty trucks in the range of 0-2720 kilograms (0-6000 lbs.) Gross Vehicle Weight Rated (GVWR) and 2721-3856 kilograms (6001-8500 lbs.) GVWR are also tested according to the 1975 FTP. However, until the 1979 model year (MY), the trucks in the 2721-3856 kilogram (6001-8500 lbs.) GVWR range were certified under the less stringent Heavy-Duty Truck procedures.

EPA test programs for determining in-use heavy-duty vehicle (HDV) emission factors use both the heavy-duty FTP, which is a steady state engine dynamometer procedure, and an actual urban road test, referred to as the San Antonio Road Route (SARR). The SARR is a 11.65-kilometer (7.24-mile) test course and includes arterial and local/collector highway segments. The

TABLE 3-13

EXHAUST EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Light Duty Vehicles

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1968	42.44 (68.30)	1.90 (3.06)
CO	1968-1974	19.35 (31.14)	3.82 (6.15)
CO	1975-1979	11.56 (18.60)	1.74 (2.80)
CO	1980	1.86 (3.00)	1.43 (2.30)
CO	1981+	0.87 (1.40)	1.24 (2.00)

[a] The Exhaust Emission Factor is calculated from the linear equation $C = A + BY$, where C is the exhaust emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and $Y = M/16{,}100$ $(M/10{,}000)$

Source: Reference 22

TABLE 3-14

IDLE EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Light Duty Vehicles

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1968	10.20 (16.42)	1.58 (2.55)
CO	1968-1974	7.91 (12.73)	1.81 (2.92)
CO	1975-1979	3.37 (5.43)	0.52 (0.83)
CO	1980	0.55 (0.88)	0.42 (0.67)
CO	1981+	0.25 (0.41)	0.37 (0.59)

[a] The Idle Emission Factor is calculated from the linear equation $C = A + BY$, where C is the idle emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and $Y = M/16{,}100$ $(M/10{,}000)$

Source: Reference 22

TABLE 3-15

EXHAUST EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Light Duty Trucks: Both Weight Categories

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1968	43.73 (70.38)	1.90 (3.06)
CO	1968-1969	26.15 (42.08)	3.38 (5.44)
CO	1970-1974	19.56 (31.48)	3.82 (6.15)
CO	1975-1978	14.57 (23.44)	3.54 (5.70)
CO	1979-1982	9.01 (14.50)	3.32 (5.34)
CO	1983+	2.40 (3.87)	1.24 (2.00)

Light Duty Trucks 0-2720 kg (0-6000 lb) GVWR

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1968	42.44 (68.30)	1.90 (3.06)
CO	1968-1974	19.35 (31.14)	3.82 (6.15)
CO	1975-1978	10.00 (16.10)	3.32 (5.34)
CO	1979-1982	9.01 (14.50)	3.32 (5.34)
CO	1983+	2.40 (3.87)	1.24 (2.00)

Light Duty Trucks 2721-3856 kg (6001-8500 lb) GVWR

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1970	48.90 (78.70)	1.90 (3.06)
CO	1970-1978	20.13 (32.40)	3.82 (6.15)
CO	1979-1982	9.01 (14.50)	3.32 (5.34)
CO	1983+	2.40 (3.87)	1.24 (2.00)

[a] The Exhaust Emission Factor is calculated from the linear equation $C = A + BY$, where C is the exhaust emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and $Y = M/16{,}100$ $(M/10{,}000)$

Source: Reference 22

TABLE 3-16

IDLE EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Light Duty Trucks, Both Weight Categories

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1968	10.30 (16.58)	1.58 (2.55)
CO	1968-1969	8.56 (13.77)	1.76 (2.83)
CO	1970-1974	8.90 (14.32)	1.81 (2.92)
CO	1975-1978	5.90 (9.49)	1.35 (2.17)
CO	1979-1982	1.13 (1.82)	0.97 (1.56)
CO	1983+	0.30 (0.49)	0.16 (0.25)
	Light Duty Trucks 0-2720 kg (0-6000 lb) GVWR		
CO	Pre-1968	10.20 (16.42)	1.58 (2.55)
CO	1968-1974	7.91 (12.73)	1.81 (2.92)
CO	1975-1978	1.26 (2.02)	0.97 (1.56)
CO	1979-1982	1.13 (1.82)	0.97 (1.56)
CO	1983+	0.30 (0.49)	0.16 (0.25)
	Light Duty Trucks 2721-3856 kg (6001-8500 lb) GVWR		
CO	Pre-1970	10.71 (17.24)	1.58 (2.55)
CO	1970-1978	11.57 (18.62)	1.81 (2.92)
CO	1979-1982	1.13 (1.82)	0.97 (1.56)
CO	1983+	0.30 (0.49)	0.16 (0.25)

[a] The Idle Emission Factor is calculated from the linear equation C = A + BY, where C is the idle emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and Y = M/16,100 (M/10,000)

Source: Reference 22

TABLE 3-17

EXHAUST EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Heavy Duty Gasoline Fueled Vehicles

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1970	169.6 (272.9)	1.90 (3.06)
CO	1970-1973	132.2 (212.7)	3.82 (6.15)
CO	1974-1978	136.0 (218.8)	3.82 (6.15)
CO	1979-1982	119.2 (191.9)	3.82 (6.15)
CO	1983+	9.56 (15.38)	6.55 (10.54)

[a] The Exhaust Emission Factor is calculated from the linear equation C = A + BY, where C is the exhaust emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and Y = M/16,100 (M/10,000).

Source: Reference 22

TABLE 3-18

IDLE EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Heavy Duty Gasoline Fueled Vehicles

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1970	15.30 (24.63)	1.58 (2.55)
CO	1970-1973	9.76 (15.70)	1.81 (2.92)
CO	1974-1978	13.62 (21.92)	1.81 (2.92)
CO	1979-1982	11.95 (19.23)	1.81 (2.92)
CO	1983+	0.96 (1.54)	3.11 (5.00)

[a] The Idle Emission Factor is calculated from the linear equation C = A + BY, where C is the idle emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and Y = M/16,100 (M/10,000).

Source: Reference 22

TABLE 3-19

EXHAUST EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Heavy Duty Diesel Fueled Vehicles

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1974	21.81 (35.10)	0
CO	1974-1978	16.78 (27.00)	0
CO	1979-1982	16.78 (27.00)	0
CO	1983+	16.78 (27.00)	0

[a] The Exhaust Emission Factor is calculated from the linear equation C = A + BY, where C is the exhaust emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and Y = M/16,100 (M/10,000).

Source: Reference 22

TABLE 3-20

IDLE EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Heavy Duty Diesel Fueled Vehicles

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1974	0.82 (1.32)	0
CO	1974-1978	0.41 (0.66)	0
CO	1979-1982	0.41 (0.66)	0
CO	1983+	0.41 (0.66)	0

[a] The Idle Emission Factor is calculated from the linear equation C = A + BY, where C is the idle emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and Y = M/16,100 (M/10,000).

Source: Reference 22

TABLE 3-21

EXHAUST EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Motorcycles

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1978	21.38 (34.40)	0.96 (1.54)
CO	1978-1979	12.60 (20.27)	2.49 (4.00)
CO	1980-1982	9.23 (14.86)	2.49 (4.00)
CO	1983+	1.68 (2.71)	1.24 (2.00)

[a] The Exhaust Emission Factor is calculated from the linear equation C = A + BY, where C is the exhaust emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and Y = M/16,000 (M/10,000).

Source: Reference 22

TABLE 3-22

IDLE EMISSION RATES FOR ALL AREAS EXCEPT CALIFORNIA AND HIGH-ALTITUDE[a]

Motorcycles

Pollutant	Model Year	A g/km (g/mi) New Vehicle Emission Rate	B g/km (g/mi) Deterioration Rate Per 16,100 km (10,000 mi)
CO	Pre-1978	5.14 (8.27)	0.80 (1.28)
CO	1978-1979	3.03 (4.87)	0.70 (1.12)
CO	1980-1982	2.22 (3.57)	0.70 (1.12)
CO	1983+	0.40 (0.65)	0.30 (0.48)

[a] The Idle Emission Factor is calculated from the linear equation C = A + BY, where C is the idle emission factor for a vehicle with cumulative mileage M, A and B are the factors listed in the above table, and Y = M/16,100 (M/10,000).

Source: Reference 22

average speed is around 32 km/hr (20 mi/hr) with about 20 percent of the time spent at idle. Since emissions from the steady state dynamometer tests are generally not easy to convert to on-the-road emissions, regression equations were developed so that on-the-road emissions (SARR) could be predicted. It is not known, however, whether the SARR accurately represents the average HDV driving patterns. Preliminary analysis of Los Angeles urban truck operation data indicates an average speed of around 42 km/hr (26 mi/hr), 10 km/hr (6 mi/hr) higher than the SARR average speed. However, the road route does have similar characteristics to the representative light duty driving schedule with respect to average road speed and percent time at idle. Since traffic is likely to be the major constraint within urban environment, it is not surprising that truck and car schedules would be similar, but the SARR (and the current LDV FTP) makes no attempt to account for the time that trucks spend idling as a result of deliveries, special operations (buses, garbage trucks, etc.), auxiliary power equipment, etc.

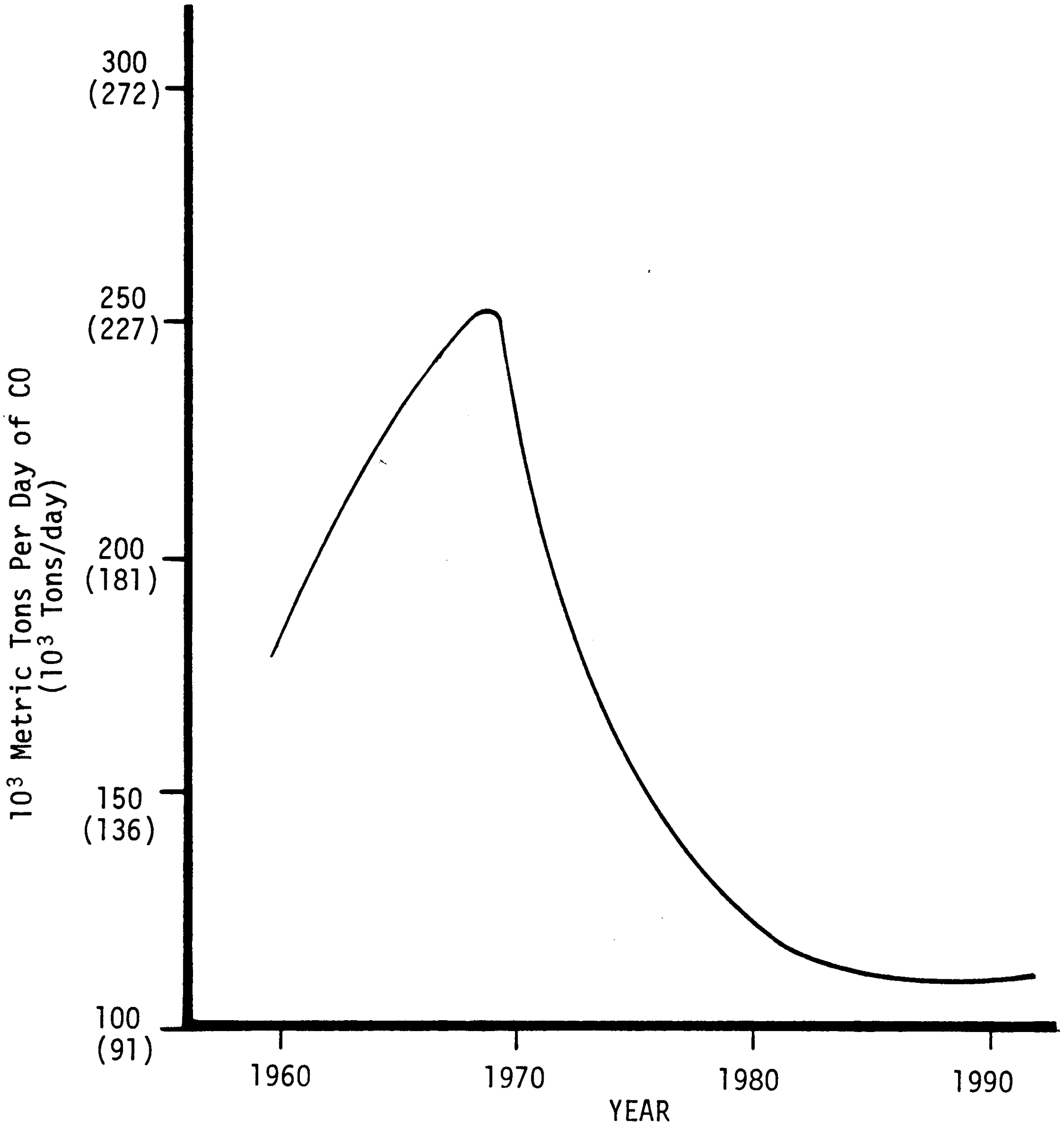
Since operational data have not been completely analyzed and trucks have not been fully tested on transient cycles developed from the operational data, the projected emission factors for heavy-duty vehicles shown in Tables 3-17 to 3-20 are based on the SARR driving schedule. The data for the HDV tables were assembled from emission factors contracts involving the testing of 35 gasoline and ten diesel in-use heavy duty trucks by chassis dynamometer versions of the FTP as well as over the SARR, and a sensitivity study of 18 gasoline and 12 diesel in-use heavy-duty trucks.

Motorcycles have become more popular and their numbers have been increasing in recent years. The majority of motorcycles are powered by either 2-

stroke cycle or 4-stroke cycle air-cooled engines. Currently, the nationwide population of motorcycles is approximately 49 percent 2-stroke and 51 percent 4-stroke.[22] Emission rates given in Tables 3-21 and 3-22 are composites of six different categories of motorcycles (small, medium, and large for 2- and 4-stroke cycle). Composite exhaust emission factors are calculated according to the 1975 FTP as stipulated in the Federal Register (Vol. 40, No. 205, October 22, 1975).

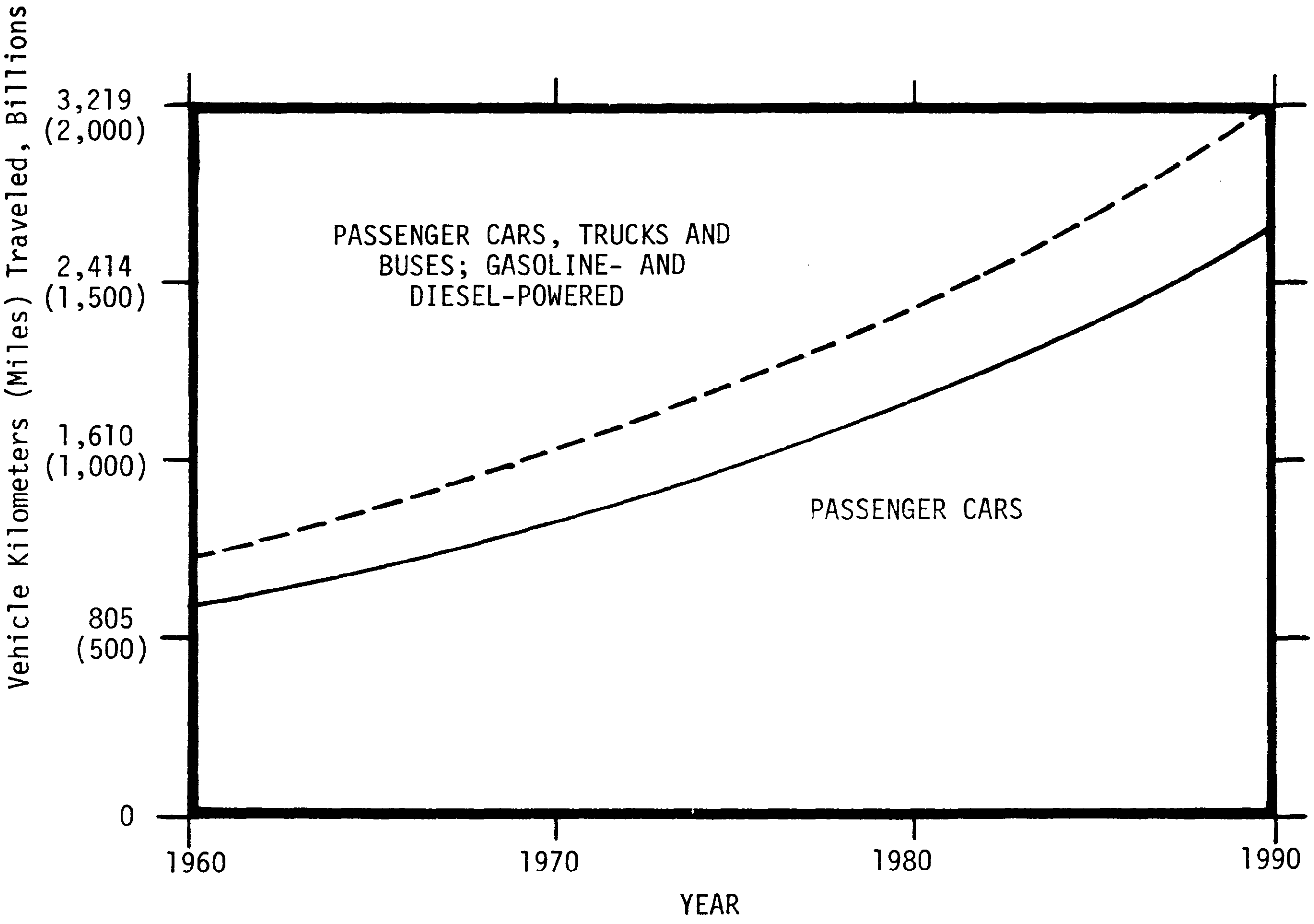
These mean composite exhaust emission rates for the different vehicles reflect the national average mileage accumulation rates of greater than 16,100 kilometers (10,000 miles) per year for newer vehicles and decreasing mileage accumulation as vehicles age. An additional series of correction factors to predict specific scenarios to reflect such variables as temperature, average speed, air-conditioning, vehicle loading, trailer towing, inspection/ maintenance credits, etc. are covered in greater detail in Reference 22, entitled Mobile Source Emission Factors For Low-altitude Areas Only, EPA 400/9-78-006, March 1978.

Carbon monoxide emission factors for mobile sources provide useful information for projecting the CO impact on ambient air quality from mobile sources. The results of one such study are shown in Figure 3-4. The curve is based upon current and proposed CO standards as well as upon a control program for new vehicles. It is not known whether the effects of vehicle and control equipment degradation were considered in this study. Figure 3-5 presents the results of another study which projected the total number of vehicle kilometers (miles) traveled through 1990. In the development of these curves,



Source: Reference 21

FIGURE 3-4. PAST AND PROJECTED CO EMISSIONS FROM MOTOR VEHICLES



Source: Reference 2

FIGURE 3-5. PAST AND PROJECTED U.S. VEHICLE TRAVEL it was assumed that the average passenger car is driven 15,100 kilometers (9400 miles) per year. Although this curve was generated in 1963, its prediction of 1976 passenger car vehicle kilometers (miles) traveled deviates from the actual number by only 3 percent.

3.6.1 The Effect of Cold Weather on CO Emissions

The Federal Test Procedure (FTP) employed by the EPA to determine compliance with specific model year emission standards specified that vehicle temperature be stabilized in a temperature environment of 20 - 25.6°C (68 - 78°F) prior to the test. While the starting-up and running of these vehicles for the first part of the test cycle constitutes a "cold start" with respect to engine coolant temperature, the cold start typically experienced under ambient temperature and considered a "cold start" by most people is <u>not</u>, in fact, simulated under the FTP conditions.

EPA has studied the effects of colder ambient temperatures on CO emissions. Quantitative information is included in References 22 through 26 listed at the end of this chapter. The emissions of CO are shown to increase significantly under non-FTP, low ambient temperatures. For example, in one study where 84 vehicles were selected for low temperature tests, 87 percent produced more CO in the low temperature FTP than in the normal FTP.[26] The first group of 14 vehicles tested at temperatures from -8.9 to -3.9°C (-5°C average) [16°F to 25°F (23°F average)] showed an 82 percent increase in CO; the second group of 26 vehicles tested at temperatures from -3.3 to 1.7°C (0°C average) [26°F to 35°F (32°F average)] showed a 74 percent increase in CO; and the third group of 13 vehicles tested at temperatures from 7.8 to 12.8°C (10°C average) [46°F to 55°F (50°F average)] showed a 21 percent increase from the normal 23.9°C (75°F) average FTP.[26]

Some vehicles of course are more sensitive than others. For example, a 1976 model year vehicle from one study produced 1.74 g/km (2.89 g/mi) when tested according to standard FTP conditions [approximately 25°C (77°F) cold soak], but when tested under non-FTP cold soak conditions of -12.2 to -3.9°C (10°F to 25°F) produced CO emissions of 11.29 g/km (18 g/mi).[24]

It is not surprising then, that the National Ambient Air Quality Standard (NAAQS) for CO is violated during cold weather conditions. Figure 3-6 shows the relative CO violations versus mean temperature. EPA is working to refine the results shown in Figure 3-6 and is also considering whether control of CO at temperature conditions other than those represented by the current FTP is warranted.

In addition to temperature, the type of driving cycle also affects CO emissions. EPA is studying this effect as well, but currently some of the driving cycle effects are less quantified than are the temperature effects. What is known is that if vehicles are operated in higher engine speed/load modes that are not well represented on the EPA tests, the emissions of CO and other pollutants can be higher than would be indicated from the Federal Test Procedure (FTP) results. Work is underway to quantify the magnitude of these effects on CO and other pollutants.

3.7 CARBON MONOXIDE CONTROL FOR NEW MOBILE SOURCES

The control of CO emissions from new mobile sources provides an important and effective approach to improving air quality with respect to CO.

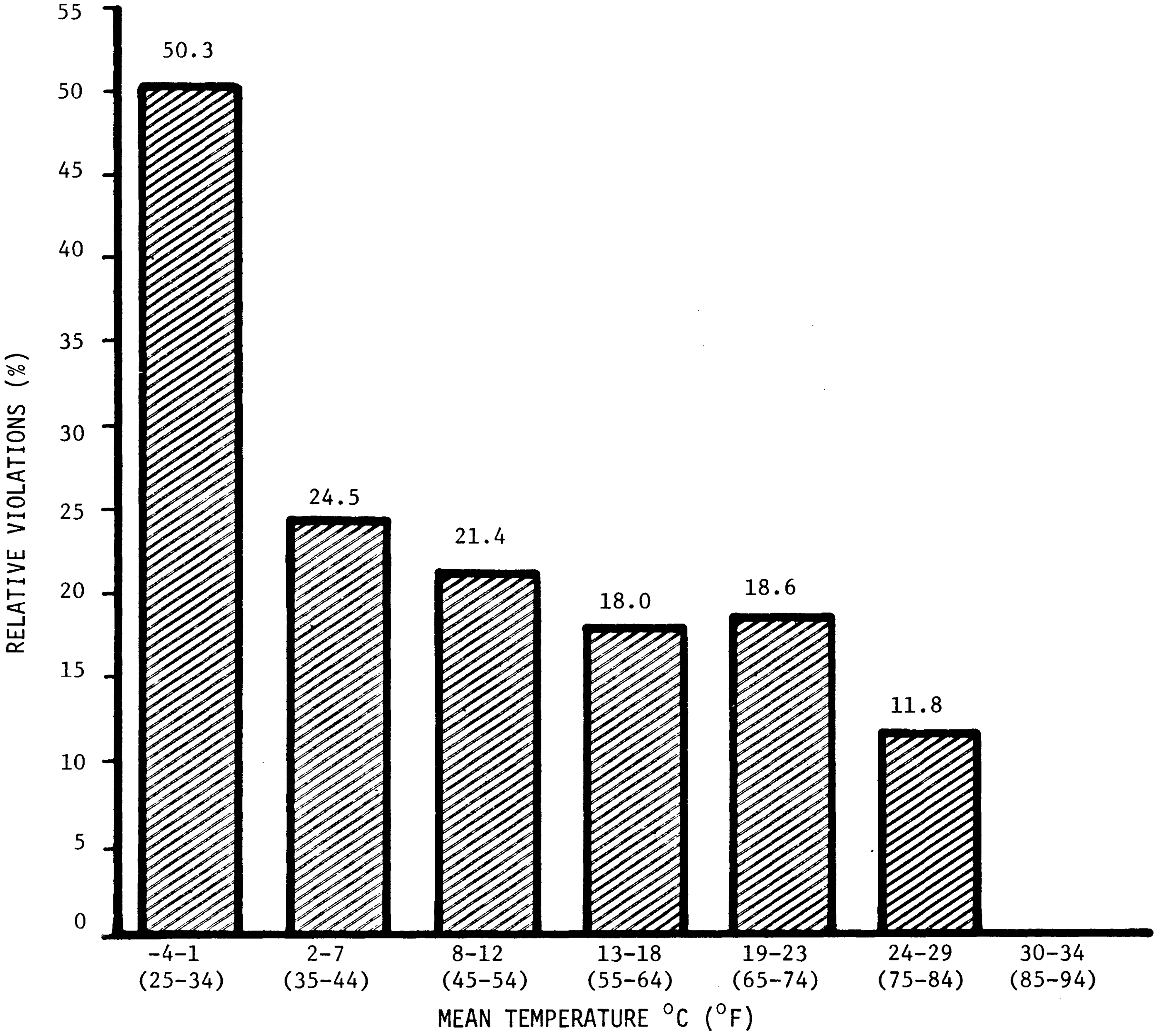


FIGURE 3-6. RELATIVE CO VIOLATIONS* VS. MEAN TEMPERATURE

*Total number of periods in violation/total number of periods monitored x 100

Control of new mobile sources has received significant developmental efforts in recent years. The driving force for this has been the implementation and enforcement of increasingly stringent CO exhaust emission standards. The objective of this section is to identify and to provide information on control techniques applicable to the reduction of CO from new mobile sources. The information on the controls is general in nature. More detailed discussions may be found in the references listed in the Special Bibliography at the end of this chapter.

3.7.1 Types of CO Controls for New Mobile Sources

The literature reports that there are basically four alternative approaches for controlling carbon monoxide emissions from new mobile sources. The first and currently one of the more effective methods is treatment of the engine exhaust gases for the removal of the CO. The second method is to reduce the formation of CO in the vehicle engine by improving fuel/air mixture distribution and control. The third is to replace the conventional premixed charge spark-ignition gasoline-fueled engines with alternative types of engines which produce less CO. The fourth method is the use of alternative fuels, such as liquid petroleum gas (LPG), liquid natural gas (LNG), hydrogen, etc. Table 3-23 contains a list of specific controls under each of these general methods and summarizes the status of development of each. The following sections briefly discuss the emission reduction benefits, costs, energy requirements, and environmental impacts associated with the application of these controls. The Special Bibliography at the end of this chapter lists sources containing more detailed information on new mobile source controls.

TABLE 3-23

CARBON MONOXIDE CONTROL TECHNIQUES FOR NEW MOBILE SOURCES

Type of Control	Status of Development
Fuel/Air Mixture	
Improved fuel metering	Extensive efforts currently underway by virtually every auto manufacturer; for example, bypass feedback carburetion and feedback fuel injection
Cold-Start Control Approaches: Quick chokes, exhaust heated intake charge, improved cold start vaporization/distribution, start catalysts, etc.	A key part of a system to control CO since much of the CO is emitted during the first few minutes of vehicle operation after startup. Active development work by all manufacturers.
Air Injection	Has been in use for several years.
Improved EGR*	Ford, GM and Chrysler are all developing electronic EGR systems. Not primarily a CO control technique, but this can be used to improve CO performance.
Electronic control for spark timing, EGR, cold enrichment, idle speed, etc.	Systems are currently in use on some vehicles and will be used nearly across the board by 1983.
Exhaust Gas Treatment	
3-way catalyst	Currently available and receiving considerable development work.
Oxidation catalyst	Currently available and receiving considerable development work.
3-way plus oxidation catalyst	Currently available and receiving considerable development work.
Thermal reactors	Currently used in some exhaust control systems.

TABLE 3-23 (Cont'd)

Type of Control	Status of Development
Alternative Engines	
Stratified charge	One variation is currently available through Honda and other types are currently receiving extensive development work (Ford PROCO and and Texaco TCCS).
"Fast Burn" (May "Fireball", MCA-JET, NAPS-Z)	Several manufacturers are considering "fast burn" concepts.
Diesel	Numerous models available.
Gas turbine	Currently undergoing extensive development by several major manufacturers.
Steam engine	Has been tested by several investigators.
Electric	Currently available via special production.
Alternate Fuels	Liquified gaseous and gaseous fuels are considered to have practical problems like storage and availability. Some advanced research is ongoing, however, on hydrogen generators. The use of ethanol/gasoline blends ("gasohol") is currently receiving widespread attention.

*Exhaust gas recirculation

Source: References 16 and 27

3.7.2 Carbon Monoxide Emission Reduction Benefits

The CO emission reduction potential for those controls listed in Table 3-23 are variable. The literature, however, does not quantify the CO emission reductions for individual control elements. The effectiveness of a vehicle's control system depends upon numerous factors including specific engine design characteristics and the target emission standard. The reader is referred to the Special Bibliography for reports containing more detailed discussions on emission reduction benefits of the various CO controls for new vehicles.

3.7.3 Costs for New Mobile Source Controls

Costs are available for many of the LDV emission control subsystems and components listed in Table 3-23. These are shown in Table 3-24. The actual costs associated with CO control for a given motor vehicle, however, depend upon such factors as the particular design characteristics of the vehicle and its engine, the actual control technology used, the type and rate of production of the components, and the target emission standard. With the variability from one engine to the next, as well as the available CO control options, more definitive costing is beyond the scope of this chapter. The cost attributable to CO control alone is difficult to determine. There are several reasons for this. First, emission control systems are typically designed to meet emission standards that include HC, CO, and NO_x requirements. Therefore, the system is designed to provide acceptable control of all three pollutants. Second, some components and subsystems control more than just one pollutant. For example, an oxidation catalyst can control both CO and

TABLE 3-24

LIGHT DUTY VEHICLE EMISSION CONTROL COMPONENT RETAIL COST

Component/Subsystem	Consumer Cost[a]
Feedback Controlled Carburetor	49-75
Electronic Fuel Injection System	95-550
Mechanical Fuel Injection System	470
Electronic Ignition System	22-30
Air Injection System	45-120
Aspirator System	8-23
Closed Loop Control System	133-172
Electronic Control Unit (ECU)	32-84
Oxygen Sensor	16-35
Throttle Position Sensor	1-7
Coolant Temperature Sensor	2-5
Crankshaft Position Sensor	7[b]
MAP/BAP Sensor[c]	15
Inlet Air Temperature Sensor	5
Wiring Harness for Electronic Controls	19-21
Oxidation Catalyst	58-140
3-way Catalyst	113-200
Heat Shield for 3-way Catalyst	8
Deceleration System	21
Idle/Deceleration System	4

[a] Dollar basis (e.g. 1978 dollars) was generally not specified.
[b] Includes requisite engine modifications.
[c] Manifold Absolute Pressure/Barometric Atmospheric Pressure Sensor.

Source: Reference 27

HC emissions, and the cost for just CO control could range from the entire cost of the catalyst (all the cost apportioned to CO control) and zero (all the cost apportioned to HC control). Extending the relative apportioning ranges to other components will yield a large overall range of costs for control of any given pollutant, including CO. An alternative procedure could be to take the entire cost of the emission control system and apportion it equally to all the pollutants. For a system which is designed to control **three** pollutants (HC, CO, NO_x) the entire system cost would be divided by three. It is realized that the major advantage of this approach is simplicity. Fourth, the components and subsystems used on vehicles, in addition to controlling pollutants, may also be used for other purposes; for example, driveability and/or performance and/or fuel economy improvements. An example of this is fuel injection, which in addition to providing emission control benefits may be able to provide driveability/performance/fuel economy benefits. Unfortunately, as is the case with emission control components and subsystems, there is no universally accepted way to apportion these costs. An example of the issues involved in a cost analysis for a given pollutant can be found in the Rulemaking Docket for EPA's revision of the oxidant (ozone) standard. During the rulemaking on this standard mobile source costs to control oxidants was an issue. In a memorandum from EPA's Office of Mobile Source Air Pollution Control Program to EPA's Office of Air Quality Planning and Standards dated 19 December 1978, the apportioning of the cost for all mobile sources to oxidant control is treated. This document can be found in the Rulemaking Docket on the revised oxidant standard as Docket Number OAQPS 78-8 and it is included as Reference 28 in the list of references for Chapter 3. Using the same method, cost apportionment for mobile source CO controls on a per vehicle or per engine basis are shown in Table 3-25, for gasoline fueled power plants. Cost estimates for new and in-use gas turbine aircraft for point source episodes are more complex and the reader is referred to Reference 40 for appropriate cost information. Other references to cost information are included as References 27 through 39 at the end of this chapter.

3.7.4 Energy Requirements for New Mobile Source Controls

The energy requirements for new mobile source controls are measured as either an increase or decrease in vehicle fuel economy. The impact on fuel economy due to control of one or more than one exhaust pollutant is a function of the level of control, the technology used, the lead time, the emphasis given to fuel economy by the designers, etc. etc. Therefore, apportioning the changes in fuel economy (either positive or negative) to control of a pollutant or pollutants is difficult. For example the average new-car fleet fuel economy for model year 1974 was about 5.95 kilometers per litre (14 MPG) and the CO emission standard (1975 FTP basis) was about 14.3 g/km (23 g/mi) CO. In model year 1975 the average new-car fuel economy was over 6.38 kilometers per litre (15 MPG) and the CO emission standard was 9.32 g/km (15 g/mi) CO. Considering only the CO difference and the fuel economy difference might lead to the conclusion that tighter CO control results in fuel economy improvements. However, because of the other factors noted above, it would not be appropriate to take credit for fuel economy improvements due to emission control.

Another factor which must be taken into account in evaluating fuel economy/emissions interactions is that fuel economy is not a free variable. Fuel economy is now regulated under the Energy Policy and Conservation Act, and car and light truck manufacturers have to meet fleet fuel economy standards that were in effect for model years 1978 and 1979 and will become increasingly stringent for model years 1980 through 1985. Table 3-26 summarizes these regulations. It appears now that if the appropriate technical approaches are used, both the fuel economy standards and the emission standards can be met, thereby making the positive or negative impacts of emission control on fuel economy a moot question.

TABLE 3-25

CO CONTROL COSTS FOR DIFFERENT FEDERAL LEVELS OF CONTROL FOR NEW GASOLINE FUELED POWER PLANTS

LDV & LDT Federal Standard	Progressive Δ Cost Increase Over Uncontrolled Engines $ (1978 basis)
24.2 g/km (39 g/mi)	18
9.32 g/km (15 g/mi)[a]	+55.32
4.35 g/km (7 g/mi)	+72.32
2.11 g/km (3.4 g/mi)	+88.66
HDV Federal Standard	
1.5% by volume	18
53.6 g/kwhr (40 g/bhp-hr)	+5.82
33.5 g/kwhr (25 g/bhp-hr)	+3.99
Motorcycles	
17 g/km (27.4 g/mi)	15.25
12 g/km (19.3 g/mi)	+4.5

[a] LDT only

Source: References 20 and 28

TABLE 3-26

FEDERAL REGULATIONS FOR LIGHT-DUTY VEHICLE FUEL ECONOMY

Model Year	Minimum Fuel Economy Kilometers/Litre (Miles/Gallon) Combined Urban and Highway Cycle
1978	7.59 (18.0)
1979	8.01 (19.0)
1980	8.43 (20.0)
1981	9.27 (22.0)
1982	10.1 (24.0)
1983	11.0 (26.0)
1984	11.4 (27.0)
1985	11.6 (27.5)

Source: Energy Policy and Conservation Act.

It should be pointed out that CO control and its effects on fuel economy has been a less controversial subject than either HC or NO_x control. This is because many of the techniques used to control CO from the engine tend to be directionally the same as those that improve fuel economy. For example, the CO control approaches to reduce cold start emissions are directionally positive for fuel economy since when the engine is running rich and producing a large quantity of CO on cold start, it is also running richer than may be considered desirable from the fuel economy standpoint. However, as discussed above, this approach and others, such as operation with high charge dilution, are not specifically credited with fuel economy benefits. Several manufacturers have demonstrated the capability to improve fuel economy while achieving very low exhaust emission levels.[27] The benefits of electronic emission control systems have not been adequately quantified yet, but their adaptation may also be utilized to support combustion with highly dilute mixtures and lean air/fuel ratios which complement effective CO control. The Special Bibliography contains references which provide more detailed information on energy requirements for control alternatives.

3.7.5 High Altitude Control for New Mobile Sources

For 1979 and 1980 only eleven manufacturers have reported that they will offer high altitude compensation systems and several have stated that these will be offered only as options on a limited number of engine/vehicle combinations at extra costs.[27] Consequently, there is a great potential that many of the new models will be sold with low altitude calibrations during model years 1979 and 1980. The Clean Air Act (CAA) amendments provide that EPA may promulgate proportional reduction standards for high altitude during the 1981 to 1983 model years. EPA anticipates proposing light duty vehicle high altitude proportional reduction standards for these model years of about 0.30 g/km (0.48 g/mi) HC, 3.1 g/km (5.0 g/mi) CO and 0.62 g/km (1.09 g/mi) NO_x. A great deal of work will be necessary in the near future for many of the manufacturers to develop appropriate control technology for control of CO at high altitude.

3.7.6 Environmental Impact of New Model Source Controls

Three of the new mobile source CO control alternatives have potentially adverse secondary emissions. These are the oxidation catalyst, the three-way catalyst, and the diesel engine. Oxidation catalysts can oxidize a portion of the sulfur dioxide in the exhaust to sulfuric acid. Although the quantity of sulfuric acid formed is relatively small, it may be possible to have high localized levels of sulfuric acid along heavily traveled roads. Extensive work sponsored by the EPA and major auto manufacturers has been done to examine this problem. More definitive actions await health effects data from EPA's Office of Research and Development, which has been studying the problem for several years. Unfortunately, definitive answers have not been generated. In addition, work is continuing by EPA and the auto manufacturers to evaluate other unregulated emissions from catalyst equipped vehicles. The Special Bibliography contains sources which present the results of much of this work.

Three-way catalysts can produce reduced species if operated in a rich air/fuel mode. Reduced species such as HCN have been studied by EPA and no specific action is contemplated at this point in time. Ammonia (NH_3) emissions have also been studied. If a system containing a 3-way catalyst operates too lean, the environmental concerns are similar to those of the oxidation catalyst, discussed above.

Diesel engines are a source of airborne particulates. Diesel particulates are currently being investigated by EPA. Tests conducted to date show that diesel engines discharge many times the amount of particulates generated by comparably sized gasoline engines. The Special Bibliography contains sources which discuss this problem in more detail.

3.8 CARBON MONOXIDE CONTROLS APPLIED TO VEHICLES AFTER SALE AND OTHER MEASURES AVAILABLE TO STATES AND/OR LOCAL GOVERNMENTS

Inspection and Maintenance (I/M) Programs and Other Transportation Control Measures are two examples of approaches to apply controls to vehicles after their initial sale. I/M Programs are discussed separately from other Transportation Control Programs for two reasons: (1) I/M programs are treated in a general manner in the Clean Air Act compared to other Transportation Control, and (2) The office within EPA that is responsible for I/M Programs is different from the office that is responsible for other Transportation Control Measures.

Section 172(b)(11) of the Clean Air Act gives three requirements for a state to meet, if the state wishes to obtain a delay (from 1982 to 1987) in meeting the National Ambient Air Quality Standards. One of these is a requirement that the state establish a specific schedule for implementation of an I/M Program.

I/M Programs, therefore, have been given special consideration by Congress. Since carbon monoxide is primarily a mobile source pollutant, I/M Programs can be considered an important control technique, and EPA is committed to assist states in the design, development, implementation, and evaluation of I/M Programs.

The discussion of I/M Programs in this chapter provides a general overview of the subject of I/M. Since each I/M Program will be to some extent unique, specific details of all possible I/M Programs cannot be included. However EPA will provide technical assistance to states in their efforts to implement I/M Programs, to ensure that the most effective benefits are obtained, and that the programs are tailored for any specific local situations that may exist.

Assistance in the I/M area can be obtained from:

Director, Emission Control Technology Division
Attention: I/M Staff
U.S. Environmental Protection Agency
Motor Vehicle Emission Laboratory
2565 Plymouth Road
Ann Arbor, Michigan 48105

3.8.1 Inspection/Maintenance Control Techniques

This section focuses on inspection/maintenance (I/M) techniques and provides information on the emission reduction approaches, costs, benefits, energy requirements, and environmental impacts.

3.8.1.1 Types of I/M Control Strategy Approaches

There are five recognized inspection alternatives for an inspection/maintenance program.[21] They are:

1) idle mode test conducted at state inspection stations,

2) idle mode test conducted at inspection stations operated by a contractor to the state,

3) idle mode test conducted at privately owned service stations and garages,

4) loaded mode test conducted at state inspection stations, and

5) loaded mode test conducted at inspection stations operated by a contractor to the state.

Table 3-27 summarizes the characteristics of idle and loaded mode testing procedures.[21] EPA and private research organizations have found idle mode testing to be virtually as effective as the loaded mode test in identifying gross HC and CO emitters, and thus a viable inspection technique.

The maintenance phase of an I/M program involves the repair of those vehicles which were identified during inspection as high emitters. The average quantity of repair work required on those vehicles failing inspection depends on the emission standards and the level of preventive maintenance provided by vehicle owners. Information compiled by existing I/M programs indicates the major causes of high carbon monoxide exhaust emission are:

1) carburetor out of adjustment,

2) air/fuel mixture imbalances, and

3) malfunction or disablement of emission control devices.

Table 3-28 contains information reported by the Portland, Oregon I/M program on the types of maintenance required for vehicles failing inspection. Reference 21 contains more detailed information regarding maintenance and its role in a successful I/M program.

3.8.1.2 Costs for I/M Programs

There are two kinds of costs for an I/M program:

1) the initial investment and operating costs for the inspection facilities, and

TABLE 3-27

CHARACTERISTICS OF IDLE MODE AND LOADED MODE TESTING

Idle Mode Testing	Loaded Mode: Steady State Test	Loaded Mode: Transient Test
1. Simple test procedure which requires minimum training for inspectors	1. Engine operated under simulated road cruise conditions	1. Engine operated under simulated urban driving cycle
2. Carburetor adjustments can be made during test	2. Includes idle test	2. Expected to provide closest correlation with FTP
3. Diagnosis of some engine maladjustments and malfunctions	3. Additional diagnostic information to repair facility	3. Variable inertial and power absorption dynamometer required
4. Can be duplicated by either public or private test systems	4. Requires dynamometers and other additional equipment	4. Driving cycle difficult to repeat accurately; cycles cannot be averaged
5. Requires minimal test time and equipment	5. Test cannot be duplicated in most repair facilities due to lack of dynamometer	5. Test cannot be duplicated in most repair facilities
6. Malfunctions can occur under loaded conditions and may not be detected	6. Requires more test time	6. Computer needed for rapid on-line data analysis; i.e., high initial costs

Source: Reference 21

2) the repair costs incurred for those vehicles which do not meet the emission standards.

The costs of inspection facilities vary significantly according to the sophistication of the program and the type of safety program existing in the area. These costs are borne by the state or, if a contractor approach is selected, by the private firm. The operating costs and repayment of the initial investment would be covered by revenues derived from a fee charged the owner when the vehicle is inspected. Experience has shown that most inspections cost between $4 and $10, with the higher figure including both emissions and safety inspection.[21]

TABLE 3-28

DISTRIBUTION OF THE TYPES OF REPAIRS REQUIRED FOR VEHICLES FAILING INSPECTION

Repair Needed	Percent Undergoing Repair
Carburetor adjustment	78
Tune-up	14
Engine overhaul	1
Valves	1
Other	6
TOTAL	100

Source: Reference 21

In addition to the inspection fee, those individuals whose vehicles do not meet the emission standards will incur repair costs. The average cost of repair has been reported for several existing I/M programs. In New Jersey, the average cost of repairs has been \$32.40; for Arizona, \$23.40; and for Oregon, \$16.00.[21] The actual number of vehicles requiring maintenance as well as the cost is determined by the stringency of the emission standards established by the state.

3.8.1.3 Benefits of I/M Program

In order to obtain full benefits from an I/M program certain minimal requirements must be met:

1) all vehicles for which emission reductions are claimed must receive regular, periodic inspections

2) to ensure that failed vehicles receive the maintenance necessary to achieve compliance with the inspection standards, they should be required to pass a retest following maintenance

3) quality control measures, such as routine maintenance, calibration and inspection of all I/M equipment, and routine auditing of inspection results, must be followed to ensure the reliability of the inspection system and accuracy of the equipment.

Beyond the minimum requirements, various other facets of an I/M program can influence the emissions reductions to be achieved.

Type of Inspection

While currently available data indicate no overall difference in the CO or HC emission reductions obtained through the use of loaded or idle mode testing, loaded mode testing is considered to be a better indicator of the actual emissions of the vehicle in-use and it provides better diagnostic information.

Inspection

Various engine component and emission control devices can deteriorate or be disabled and have no noticeable effect on the way a car drives or on its fuel consumption. The performance of periodic inspection provides a suitable deterrent to either maladjustment or disablement because of the threat of not meeting the required standards.

Mechanics Training

The air quality benefit from an I/M program is dependent, in part, on the ability of the service industry to properly perform the repair work necessary to lower emissions. Some savings in repair costs may also result from the proper training since the mechanics would be more familiar with the problems and the best solutions for them.

Vehicle Exemptions

The total emission reductions that result from an I/M program are directly dependent on the number and types of vehicles inspected and the requirement that maintenance be performed. In some cases, it may be desirable to exempt vehicles that include different control technology (diesels, stratified charge, LPG/LNG, etc.). In some cases, it may also be desirable to exempt vehicles when the estimated repair cost is a major percentage of the vehicle value.

Frequency of Testing

Most existing I/M programs require annual inspection. This frequency is justified on the basis that it minimizes costs and maximizes public acceptance while maintaining a reasonably high level of emission reduction. When annual inspection is required for vehicle registration it helps enforcement of an I/M program. A semi-annual program would involve substantially higher program costs arising from the need for a greater number of inspecttion lanes, as compared to an annual inspection program. A biennial program, while certainly providing some emission benefits, will lose some of the effectiveness of an annual program because cars may be allowed to deteriorate to a higher level.

Emission Standards

Most importantly, the I/M emission standards, or "cut points," determine the overall emission reduction potential of the program. The cut point is the level of emissions which distinguishes between those vehicles requiring emissions-related maintenance and those that do not. The cut points that are selected define a "stringency factor" which is a measure of the rigor of the program based on the estimated fraction of the vehicle population whose emissions would exceed cut points for carbon monoxide in the absence of an I/M program.

There are two basic concerns that constrain the selection of I/M emission standards to determine the emission reduction potential. While I/M standards or "cut points" should be set to achieve a desired emission reduction, the cut point should be limited to a level that will be acceptable to both the general public and the repair industry. As experienced by other programs, negative public sentiments may result if an excessive volume of vehicles do not comply with I/M standards at first inspection. Further difficulties will arise if the total of the noncomplying vehicles exceed the available capacity of the repair industry. The necessary vehicle maintenance will be compromised under these conditions. Cut points must be set at a level where potential emission reduction benefits are maximized while impacts to the public are minimized. As stated above, emission reductions achieved with any particular I/M program are a result of a combination of the emission reductions obtained through the optimal selection of various options. Table 3-29 lists credits for CO in percent emission reductions that can be achieved in 1987 through an inspection/maintenance program which was implemented in 1982. The "basic" reductions (i.e., those that are achieved through an annual inspection of light-duty vehicles) are broken down by Technology I and Technology II vehicles and by Technology III and Technology IV vehicles.

Technology I vehicles include those light-duty vehicles subject to pre-1975 federal emission standards; Technology II vehicles are subject to 1975 and later model year federal exhaust emission standards; Technology III and Technology IV vehicles are subject to 1980 and 1981 federal exhaust emission standards, respectively. A review of these data indicates that a 20 percent stringency factor I/M program implemented on all light-duty vehicles (LDVs) would achieve the policy required 25 percent reduction in CO for LDVs, and that larger emission reductions are possible with mechanic's training. (The reader is referred to the proposed revision of Appendix N of Reference 41

TABLE 3-29

CO FTP EMISSION LEVELS AND EMISSION REDUCTIONS IN 1987 DUE TO I/M PROGRAM IMPLEMENTED IN 1982[a]

		Technology I & II LDVs		Technology III & IV LDVs		All LDVs	
	Stringency	g/km (g/mi)	Reduction	g/km (g/mi)	Reduction	g/km (g/mi)	Reduction
Without mechanic training	10%	11.11 (17.88)	13%	11.90 (19.15)	6%	10.30 (16.57)	19%
	20%	10.58 (17.03)	17%	11.61 (18.69)	9%	9.48 (15.26)	25%
	30%	10.14 (16.32)	20%	11.48 (18.47)	10%	8.90 (14.33)	30%
	40%	10.00 (16.09)	21%	11.16 (17.96)	12%	8.44 (13.59)	34%
	50%	9.83 (15.82)	23%	10.89 (17.53)	14%	8.01 (12.89)	37%
With mechanic training	10%	10.57 (17.01)	17%	9.71 (15.62)	24%	7.56 (12.17)	41%
	20%	9.98 (16.06)	22%	9.30 (14.97)	27%	6.57 (10.57)	48%
	30%	9.50 (15.29)	25%	9.19 (14.79)	28%	5.98 (9.62)	53%
	40%	8.87 (14.27)	27%	9.00 (14.48)	29%	5.59 (8.99)	56%
	50%	9.13 (14.70)	28%	8.95 (14.40)	30%	5.37 (8.64)	58%

[a] Assumed program is implemented in 1982. Emission reductions are calculated using the computer program MOBILE-1 (September 1978). The AP-42 low altitude base emission factor is 12.71 g/km (20.46 g/mi). Emission reductions are based on this number.

Source: Users Guide to MOBILE-1, Mobile Source Emissions Model, August 1978, EPA-400/9-78-007, and Reference 22.

for a more detailed discussion.) The final revised Appendix N should be consulted when it appears as a final rule in the Federal Register.

Warranty Provisions

The Emission Control System Performance Warranty contained in Section 207(b) of the Clean Air Act provides warranty coverage to motorists in areas having an I/M program. The Emission Performance Warranty, upon promulgation of a regulation by EPA, will require the automobile manufacturer to bear the cost of repair of any properly maintained and operated vehicle which fails an EPA established emissions test within 24 months or 38,600 kilometers (24,000 miles), whichever occurs first, of the original sale to the ultimate purchaser. After this period, the warranty applies only to catalytic converters, thermal reactors or other components installed on or in a vehicle for the sole or primary purpose of reducing vehicle emissions. These warranty provisions are thus an additional benefit to individuals residing in areas with an I/M program.

3.8.1.4 Energy Requirements for I/M Program

A slight energy benefit is likely to result from the application of an I/M program rather than an energy penalty, particularly if mechanics have been trained in emission oriented maintenance. Fuel savings can result on those vehicles that are in need of repair or in a state of maladjustment. The extent of such benefits have recently been quantified by EPA.[42]

3.8.2 Transportation Control Programs

In addition to I/M programs, there are several other Transportation Control Measures that could possibly be used by state and/or local authorities to control motor vehicle-related carbon monoxide emissions.

A list of some of these measures can be found in Section 108(f) of the Clean Air Act:

1) programs to control vapor emissions from fuel transfer and storage operations and operations using solvents;

2) programs for improved public transit;

3) programs to establish exclusive bus and carpool lanes and areawide carpool programs;

4) programs to limit portions of road surfaces or certain sections of the metropolitan areas to the use of common carriers, both as to time and place;

5) programs for long-range transit improvements involving new transportation policies and transportation facilities or major changes in existing facilities;

6) programs to control on-street parking;

7) programs to construct new parking facilities and operate existing parking facilities for the purpose of park and ride lots and fringe parking;

8) programs to limit portions of road surfaces or certain sections of the metropolitan area to the use of nonmotorized vehicles or pedestrian use, both as to time and places;

9) provisions for employer participation in programs to encourage carpooling, vanpooling, mass transit, bicycling, and walking;

10) programs for secure bicycle storage facilities and other facilities, including bicycle lanes, for the convenience and protection of bicyclist, in both public and private areas;

11) programs of staggered hours of work;

12) programs to institute road user charges, tolls, or differential rates to discourage single occupancy automobile trips;

13) programs to control extended idling of vehicles;

14) programs to reduce emissions by improvements in traffic flow;

15) programs for the conversion of fleet vehicles to cleaner engines or fuels, or to otherwise control fleet vehicle operations;

16) programs for retrofit of emission devices or controls on vehicles and engines, other than light-duty vehicles, not subject to regulations under section 202 of Title II of this Act; and

17) programs to reduce motor vehicle emissions which are caused by extreme cold start conditions.

EPA is in the process of preparing reports, in conjunction with the U.S. Department of Transportation, that cover each of these areas. At the time of the preparation of this document, only one has been completed: report EPA 400/2-78-002a, Air Quality Impacts of Transit Improvements, Preferential Lane, and Carpool/Vanpool Programs.

Questions about the status of other reports on the above-listed subjects, and requests for information and assistance in this general subject area can be directed to the EPA office listed below:

Director
Office of Transportation and Land Use Planning (AN-445)
U.S. Environmental Protection Agency
401 M. St., S.W.
Washington, D.C. 20460

3.8.2.1 Transportation Control Strategy Approaches

Transportation-related air quality problems can be either localized or regional. Localized problems generally result in CO concentrations exceeding either the one-hour, or more likely, the eight-hour CO National Ambient Air Quality Standard. Localized violations of the standards are usually associated with high traffic volumes and congested traffic conditions frequently found in densely populated urban areas. Regional transportation-related air quality problems are typically a result of vehicle and stationary source hydrocarbon and nitrogen oxide emissions reacting in the atmosphere to produce oxidant pollutants. Transportation-related air pollution problems of localized and regional types are illustrated in Table 3-30.

The distinction between the pollutants CO and oxidant is important. Transportation control programs designed for localized problems are different than those for regional air quality problems. For example, a transportation systems management (TSM) program to implement a reserved lane for carpools and buses on a particular freeway may reduce CO emissions in the vicinity of the freeway, but is unlikely to have a noticeable impact on regional oxidant emissions. Similarly, a regional car pool program may contribute to a reduction in hydrocarbon and nitrogen oxide emissions, but generally may have less impact on localized CO concentrations.

Four transportation control programs have been identified as having the greatest potential for controlling localized violations of the CO standards in a cost-effective manner.[43] These programs were identified through a comprehensive review of both operational and proposed transportation control programs. They are:

TABLE 3-30

ILLUSTRATIVE TRANSPORTATION-RELATED AIR POLLUTION PROBLEMS

Type of Problem	Pollutant	Air Quality Standard	Typical Impact Area	Selected Travel Factors Contributing to Problem
Localized	Carbon Monoxide	8 Hour 10,000 µg/meter^3 (9 PPM)	• Intersections	• High Vehicular Traffic Volumes
		1 Hour 40,000 µg/meter^3 (35 PPM)	• Locations Adjacent to Freeways and Arterials	• Stop and Go Traffic Flows (e.g., Idling)
Regional	Photochemical Oxidant	1 Hour 160 µg/meter^3 (0.08 PPM)	• Overall Urban Area (Based on Oxidant Concentrations Measured at Specific Locations)	• High Vehicular Traffic Volumes • High Speeds

Source: Reference 43

1) freeway priority treatment for high occupancy vehicles;

2) arterial priority treatment for high occupancy vehicles; and

3) areawide carpool and vanpool programs

4) transit service improvement programs.

In order to quantitatively assess the air quality and related impacts of interest, 20 prototype scenarios were analyzed.[43] These prototype scenarios were designed to provide representative findings on the range of travel, air quality/emission, fuel consumption, cost and economic impacts of TSM programs which appear to have potential for localized or regional air quality improvement. These scenarios are presented in Tables 3-31 and 3-32 respectively for localized and regional prototypes. The strategies considered have the potential for achieving improvements in regional air-quality -- especially when considerations of strategies which include strong incentives and nonincentives (e.g., auto restricted zones, limited idle/engine off, pricing, etc.) not within the scope of this report are included in the total transportation plan. The strategies which appear to have the greatest potential for achieving improvements in localized CO air quality in a cost effective manner include:[43]

1) with-flow freeway lanes reserved for buses and carpools;

2) contraflow bus lanes on freeways;

3) metered freeway access ramps with bus by-pass lanes;

4) contraflow bus lanes on major one-way arterial pairs;

5) provision of high level express bus service with reduced fares, operating in mixed traffic on major arterials or freeways;

TABLE 3-31

SUMMARY OF ESTIMATED IMPACTS FOR THE LOCALIZED PROTOTYPE SCENARIOS

Prototype Scenario		Impact on A.M. Peak Hour Corridor Vehicle Volume		Impact on A.M. Peak Hour CO Concentrations in $\mu g/m^3$ At Reference Receptor From Affected Facility Emissions				Programs Costs In 1976 Dollars (x1,000)	
				Typical Good Dispersion		Typical Poor Dispersion			
ID No.	Brief Title	Base Peak Hour Volume	Percent Change	Base Value	Change	Base Value	Change	Capital (One-time Implementing tion)	Operating (Per Year)
1	Expanded express bus service in mixed freeway traffic; favorable impacts	19,667	-1.47%	5,756	-139	8,210	-203	3,168/4,788	1,447
2	Freeway lane reserved for buses and carpools; favorable impacts	19,667	-6.30%	5,756	-554	8,210	-762	3,720/6,350	1,839
3	Ramp metering and bus by-pass lanes; favorable impacts	19,667	-3.06%	5,756	-388	8,210	-537	5,224/6,844	1,703
4	Reserved bus/pool lane, ramp metering, and bus by-pass lanes; modest impacts	19,667	-3.971%	5,756	N.A.[a]	8,210	N.A.[a]	4,862/6,482	1,751
5	Reserved bus/pool lane, ramp metering, and bus by-pass lanes; favorable impacts	19,667	-6.98%	5,756	-603	8,210	-832	6,248/7,868	2,266
6	Contraflow freeway lane reserved for buses; favorable impacts	14,750	-1.69%	4,798	+226	6,759	+227	962	541
7	Contraflow bus lane, expanded express bus service, and park-and-ride lots; favorable impacts	14,750	-3.72%	4,798	+100	6,759	+104	3,668/5,288	1,818
8	Contraflow bus lane, expanded express bus service, and lots; assuming 70%/30% directional split; favorable impacts	13,500	-4.07%	4,066	-115	5,748	-181	3,668/5,288	1,181
9	Reserved arterial median lane for express buses; favorable impacts	3,750	-15.47%	4,964	-779	6,485	-998	3,594/4,134	1,130
10	Contraflow curb lane for local buses on pair of one way arterials; favorable impacts. (Inbound arterial/Outbound arterial)	5,000	-4.40%	3,992/3,349	-532/+365	4,992/4,793	-685/+474	468	123

[a] Not Available

Source: Reference 43

TABLE 3-32

SUMMARY OF ESTIMATED IMPACTS FOR THE REGIONAL PROTOTYPE SCENARIOS

PROTOTYPE SCENARIO		CHANGE IN REGIONAL WEEKDAY VMT		CHANGE IN REGIONAL WEEKDAY HIGHWAY EMISSIONS IN TONS†			CHANGE IN ANNUAL HIGHWAY FUEL CONSUMPTION IN MILLIONS OF LITERS (MILLIONS OF GALLONS)	PROGRAM COSTS IN 1976	
ID No.	BRIEF TITLE*	AS PERCENT OF TOTAL VMT	AS PERCENT OF WORK TRIP VMT	HC	NO_x	CO		CAPITAL (ONE-TIME IMPLEMENTATION)	INCREMENTAL OPERATING (PER YEAR)
11	Carpool/Vanpool Program, Medium Size City; Favorable Impacts	-1.5%	-5.0%	-1.8*	-0.6*	-15.0*	-9.8 (-2.6*)	-	78
12	Carpool/Vanpool Program, Large City; Favorable Impacts	-1.5%	-5.0%	-8.3	-2.8	-63.4	-43.9 (-11.6)	-	404
13	Reserved Bus/Pool Lanes, Ramp Metering, and Bus By-Pass Lanes on All Appropriate Freeway; Modest Impacts	-0.25%	-0.8%	-0.3	-0.5	+ 2.6	-5.7 (-1.5)	14,586/19,446	5,253
14	Reserved Bus/Pool Lanes, Ramp Metering, and Bus By-Pass Lanes on All Appropriate Freeways; Favorable Impacts	-0.44%	-1.5%	-2.5	-0.4	-17.9	-10.2 (-2.7)	18,744/23,604	6,798
15	Reserved Median Lane for Express Buses on Appropriate Radial Arterials; Modest Impacts	-0.23%	-0.8%	+2.1	-0.4	+37.2	-6.1 (-1.6)	18,868/21,704	5,984
16	Reserved Median Lane for Express Buses on Appropriate Radial Arterials; Favorable Impacts	-0.38%	-1.3%	-0.7	-0.6	+ 5.8	-11.0 (-2.9)	18,868/21,704	5,984
17	Carpool/Vanpool Program and Freeway Reserved Lanes; Modest Impacts	-1.0%	-3.3%	-2.4	-1.9	-29.1	-27.3 (-7.2)	9,804/14,664	5,408
18	Carpool/Vanpool Program and Freeway Reserved Lanes; Favorable Impacts	-1.9%	-6.3%	-10.5	-3.3	-81.1	-53.4 (-14.1)	11,190/16,050	5,921
19	Carpool/Vanpool Program, Reserved Lanes, Ramp Metering, and Bus By-Pass Lanes; Modest Impacts	-1.0%	-3.3%	-4.5	-1.6	-29.0	-27.6 (-7.3)	14,586/19,446	5,957
20	Carpool/Vanpool Program, Reserved Lanes, Ramp Metering, and Bus By-Pass Lanes; Favorable Impacts	-1.9%	-6.5%	-10.9	-3.3	-83.9	-53.8 (-14.2)	18,744/23,604	7,202

*All scenarios except #11 are for a "large" city (1,000,000 + SMSA population). Scenario 11 is set in a "medium size" city (500,000 - 1,000,000 SMSA population).

†Estimated at 75°F assuming uninterrupted traffic flow conditions.

Source: Reference 43

6) provision of high level express bus service (possibly with reduced fares), combined with a reserved lane for buses and carpools on the appropriate freeway facility; and

7) provision of high level express bus service (possibly with reduced fares), combined with a reserved median lane for buses and bus preemption of traffic signals on an appropriate arterial.

3.8.2.2 Emission Reduction Benefits of Transportation Control Programs

The freeway-based localized prototype scenarios (Scenarios 1-8, Table 3-30) are likely to achieve reductions on overall peak hour corridor traffic volumes ranging between 1.5 percent and 7 percent. The arterial scenarios analyzed (Scenarios 9 and 10) can also promote 4 to 15 percent reductions in peak hour vehicular volumes. As is true for the freeway scenarios, the attainment of such reductions is highly dependent upon the specific setting in which such strategies may be implemented. However, the percentage reductions in vehicular volumes for arterials are based on smaller base volumes and are not fully comparable to the corridor volumes in the freeway scenarios.

Generally the relative reductions in peak hour CO concentrations (under typical, good dispersion conditions) shown in Table 3-31 are several percentage points higher than the corresponding reductions in peak hour corridor vehicle volumes but are generally several percentage points lower than the corresponding reductions in peak direction freeway vehicle volumes. In Scenarios 6 and 7, CO concentrations are estimated to increase relative to the base conditions. The increase in CO concentrations in several contraflow reserved freeway lane scenarious reflect the travel and meteorological conditions assumed in those scenarios. The results do not indicate that contraflow lanes, per se, have undersirable air quality effects, but rather illustrate the importance of carefully analyzing the potential air quality effects of implementing a contraflow lane on freeways carrying heavy traffic volumes in the "off-peak" direction.

Scenarios 13 through 17 (Table 3-32) which involve the implementation of reserved lanes on multiple radial freeways or arterials in a region, generally resulted in total regional and work trip vehicle miles traveled (VMT) reductions of less than 0.5 percent and 1.5 percent, respectively. The small reductions in VMT are in large part related to the limited size of the peak period radially-oriented central business district (CBD) travel market in most large urban areas. For example, home to work trips and VMT comprise approximately 20 percent and 30 percent of total weekday regional person trips and VMT, respectively. Travel survey data suggest that only 15 percent of home to work trips are oriented to the CBD of urban areas exceeding 1 million population. However, those urban areas with especially large percentages of CBD-oriented travel could experience higher reductions in VMT than those estimated in this study.

Despite their limitations in reducing regional air pollution emissions, the freeway reserved lane strategies show considerable potential for reducing peak period travel congestion along radial travel corridors when applied under appropriate travel conditions. These strategies can contribute to reductions in CO concentrations along heavily traveled freeways and can also contribute to reductions of vehicular travel with CBD's.

3.8.2.3 Costs of Transportation Control Programs

Table 3-31 presents the estimated capital and annual operating costs for the localized scenarios. They represent order of magnitude estimates based on costs published in the literature.[43]

The largest individual cost item for all of the scenarios is for improvements to express bus service. Generally, the geographic coverage and the frequency of express bus service were assumed to increase significantly in order to complement the reserved high occupancy vehicles (HOV) lanes and attract large numbers of auto travelers. The annual cost of bus service shown in Table 3-31 represents the incremental cost of providing bus service above that assumed in the base case (i.e., "before" case).

The costs of implementing ramp metering and park-and-ride facilities are also significant. With regard to the cost of park-and-ride lots, two conditions are assumed. If use can be made of existing parking facilities at shopping centers or other locations, the capital cost of such facilities would be negligible. However, such arrangements may not be feasible in many locations, so the full capital cost of constructing the park-and-ride facilities is also presented. For both of these conditions, the cost of operating and maintaining the park-and-ride lots is assumed to be a public cost.

Based on analyses of express bus operations in Minneapolis and Seattle, annual operating revenues may only offset approximately 50 percent to 66 percent of the annual operation and maintenance costs of express bus service shown in Table 3-32. Consequently, sizeable annual operating subsidies may be required to operate express bus services such as those assumed in the localized scenarios. If fare reductions are implemented, the subsidy requirements are likely to be even more significant. The economic impacts of the regional scenarios are likely to be small. More details on the economic impacts and the nature and magnitude of the impacts are contained in Reference 43.

3.8.2.4 Energy Requirements of Transportation Control Programs

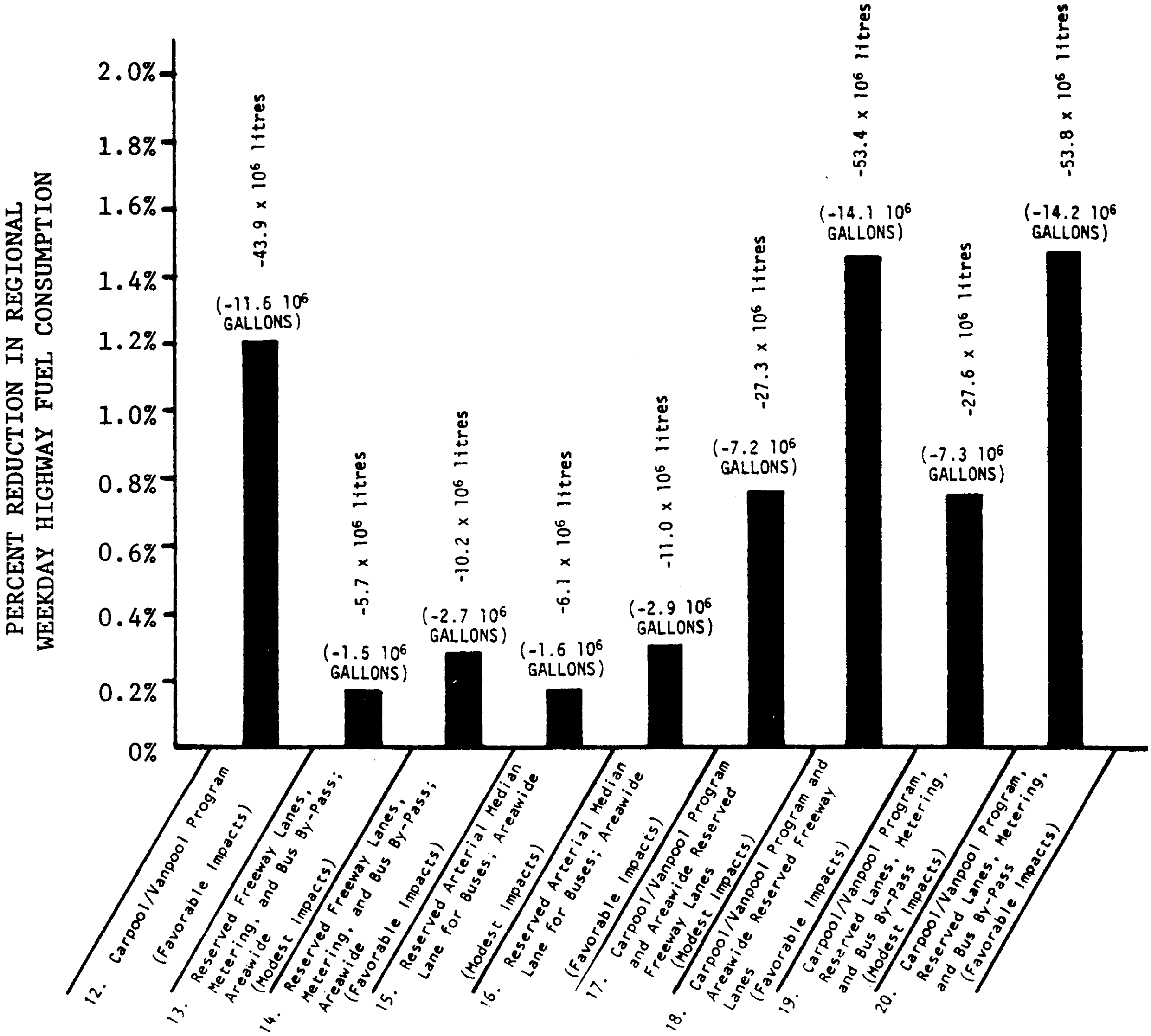
Transportation control programs by their very nature promote lower fuel consumption for the areas where they are implemented. Actual quantification of this decrease is not available for the localized prototype scenarios shown in Table 3-31. Estimated impacts for nine of the regional scenarios in a large urban area are shown in Figure 3-7 with the most significant gains being accomplished with carpool/vanpool program variations (7.2 to 14.2 million gallons per weekday saved in highway fuel consumption).

3.8.2.5 Environmental Impact of Transportation Control Programs

The only potential adverse environmental impact associated with implementation of the scenarios listed in Tables 3-30 and 3-31 would be increased particulate emissions and odor problems associated with the use of Diesel-powered vehicles, i.e., buses. Diesel engine discharge much larger quantities of particulates than gasoline engines. Odor is another problem resulting from diesel engines. See Reference 22 for a more detailed discussion of diesel engine emissions.

3.9 Special Bibliography for Chapter 3

The objective of this bibliography is to furnish more detailed and basic information on each of the topics covered in this chapter. The reference numbers refer to the references for Chapter 3.



*ESTIMATED ABSOLUTE REGIONAL CHANGE IN ANNUAL HIGHWAY FUEL CONSUMPTION FOR PROTOTYPE URBAN REGION OF APPROXIMATELY 2,500,000. 3,000,000 SMSA POLLUTION AND A BASE ANNUAL HIGHWAY FUEL CONSUMPTION OF 4955 MILLION LITRES (1,309 MILLION GALLONS) FULL 365 DAYS, INCLUDING WEEKENDS AND HOLIDAYS).

Source: Reference 43

FIGURE 3-7 ESTIMATED IMPACTS FOR NINE REGIONAL SCENARIOS IN A LARGE URBAN AREA: REGIONAL HIGHWAY FUEL CONSUMPTION

3.9.1 TYPES OF CONTROL TECHNIQUES

3.9.1.1 New Mobile Source Controls

References 3, 16, and 27

3.9.1.2 In-Use Mobile Source Controls

References 2, 3, 20, 21, 27, and 43

3.9.1.3 Inspection/Maintenance Programs

Reference 21

3.9.1.4 Transportation Control Programs

Reference 43

3.9.2 EMISSION REDUCTION BENEFITS

3.9.2.1 New Mobile Source Controls

References 3, 16, and 27

3.9.2.2 In-Use Mobile Source Controls

References 2, 3, 20, 21, 22, 27, 41, 42, and 43

3.9.2.3 Inspection/Maintenance Programs

Reference 21

3.9.2.4 Transportation Control Programs

Reference 43

3.9.3 COSTS

3.9.3.1 New Mobile Source Controls

References 18 through 29

3.9.3.2 In-Use Mobile Source Controls

References 21, 27, and 43

3.9.3.3 Inspection/Maintenance Programs

Reference 21

3.9.3.4 Transportation Control Programs

Reference 43

3.9.4 ENERGY REQUIREMENTS

3.9.4.1 New Mobile Source Controls

Reference 27

3.9.4.2 In-Use Mobile Source Controls

References 21 and 43

3.9.4.3 Inspection/Maintenance Programs

Reference 21

3.9.4.4 Transportation Control Programs

Reference 43

3.9.5 ENVIRONMENTAL IMPACTS

3.9.5.1 New Mobile Source Controls

References 17, 18, 19, 21, 27, and 43

3.9.5.2 In-Use Mobile Source Controls

References 17, 18, 19, 21, 27, and 43

3.9.5.3 Inspection/Maintenance Programs

Reference 21

3.9.5.4 Transportation Control Programs

Reference 43

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4. STATIONARY INTERNAL COMBUSTION SOURCE CONTROL

4.1 PROCESS DESCRIPTION

4.1.1 Engine Design

One of the oldest forms of combustion engines is the gas turbine which pre-dates, by far, the reciprocating piston engine. The main components of the gas turbine consist of a compressor, a turbine, and a combustion chamber. In operation, air is drawn into the compressor, compressed, and then passed, in part, through the combustion chamber. The high temperature gases leaving the combustion chamber mix with the main body of air flowing around the combustor. This hot gas, with greatly increased volume, is led to a nozzle ring where the pressure is decreased and the velocity is increased. The high velocity gas is directed against the turbine wheel and the kinetic energy of the gas is utilized in turning the drive shaft, which also drives the compressor.[1] The gas turbine can be operated at much higher speeds than other engines because of the absence of reciprocating parts. This continuous flow system, as contrasted to the intermittent flow of the piston engine, produces a high specific power output from a small machine. The sizes of gas turbines can range from about 150 to 60,000 kilowatts (200 to 80,000 horsepower) all operating at high speeds.

Reciprocating (piston) engines produce power by combustion of a fuel/air mixture confined in a small space between the head of a piston and the surrounding cylinder. Expansion of the high pressure combustion gases pushes the piston producing a linear force which is converted to rotary torque by a crank shaft. Fuel/air mixtures are ignited in reciprocating engines by either compression ignition (CI) or by spark ignition (SI). Compression ignition engines usually burn diesel fuel or dual fuel (diesel fuel plus natural gas). Ignition occurs spontaneously when the fuel is injected into the cylinder containing compression-heated air or an air/gas mixture. Spark ignition engines usually burn gasoline, liquid petroleum gas (LPG), or natural gas, and combustion is initiated by the spark of an electrical discharge in the combustion chamber. Reciprocating engines are characterized by their: (1) cylinder arrangement and number of cylinders, (2) displacement, (3) method of ignition, (4) fuel type, (5) number of piston strokes per power cycle, (6) compression ratio, (7) rated speed and output (8) method of cooling, (9) method of aspiration, and (10) fuel metering method.

Air can be introduced either by natural aspiration or under pressure. In natural aspiration, air is forced into the cylinder by the vacuum created by the moving piston. The pressurized method of air introduction is called supercharging or turbocharging. In the type of supercharging called turbocharging, an exhaust gas-driven turbine powers a compressor which boosts the pressure of the inlet charge. This allows more fuel to be processed through the engine in a given amount of time, and since the combustion is usually not impaired, more power results. Since air temperature increases with an increase in pressure, the air charge is often cooled to offset charge density losses from heating during compression and/or to prevent premature autoignition (called intercooling). Although the Roots-type blowers, typically used on 2-stroke cycle blower scavenged engines, supply air at higher pressure than atmospheric, the main reason for their use is for exhaust gas scavenging. Higher cylinder inlet charge densities, therefore, can be obtained with other types of supercharging such as turbocharging or turbocharging in series with Roots-type blowers.

Spark-ignition engines are usually of the open chamber design although some spark-ignition engines may be of the divided chamber or pre-combustion chamber type (e.g., the Honda CVCC). Carburetion or port injection are typically used in spark ignition engines although direct fuel injection may also be used (e.g., the Ford PROCO and Texaco TCCP stratified charge combustion systems). For compression-ignition engines, direct fuel injection is commonly used with open-chamber engines and indirect fuel injection (injection into the secondary chamber) is commonly used with divided chamber engines. Examples of divided chamber engines are the pre-chamber, swirl-chamber and energy cell or La Nova chamber engines.

4.1.2 Engine Applications

Stationary gas turbine and reciprocating internal combustion engines are widely used by the oil and gas industry for production and pipeline applications, in electric power generation, and in industrial and agricultural applications. Gas turbine engines are more commonly used in electric utility power plants and as a standby source of electric power generation and in pipeline transport systems.

The applications of spark ignition engines depend on engine size (horsepower) and fuel type. Small gasoline engines in the range of 1 to 8 kw (1 to 10 hp) are used for domestic, agricultural, and commercial power tools and equipment (power saws, lawn mowers, and portable compressors, pumps, and electric generators). Medium-size gasoline engines in the range of 40 to 150 kw (50 to 200 hp) are found in commercial and construction site compressors, pumps, blowers, lift trucks, and electric power generator units. Medium-large spark-ignition engines in the range of 150 to 750 kw (200 to 1000 hp) are usually fueled by natural gas. Most are of the naturally-aspirated type. They are used for heavy-duty, medium-speed applications such as gas compressors or standby power generators. Large spark-ignition engines of 750 kw and up (1000 hp and up) are always operated on gaseous fuels and are both 4- and 2-stroke cycle, low-speed (300 to 400 rpm) engines. They are used for compressor drives, gas recompression (in transmission lines), gas plant compressors, refinery process compressors, water pumping, sewage pumping, and electric power generator drives for continuous operation. The total number of gasoline and natural gas-fueled spark ignition engines in use is much larger than the number of diesel and dual fuel (compression ignition) engines.[2]

Diesel engines are widely used in electric power generation, oil and gas production and transport, and in operation of small electric power and pumping stations. Electric utilities employ diesel engines as prime movers of continuous and peaking-power generators and in standby power installations. The transmission line and process compressors used in the petroleum industry are usually powered by diesel engines. They are frequently used to drive oil and gas well drilling and pumping equipment, water pumps, and electric generators. Municipalities and commercial firms use diesel engines to supply part of their electric power needs and to power total energy systems and water and sewage pumping units.

Large low-speed diesel engines above 750 kw (1000 hp) are designed for continuous operation. Medium, 75 to 750 kw (100 to 1000 hp), and small, below 75 kw (100 hp), stationary diesel engines are usually derivatives of engines developed for motor vehicle use.[2] They are used mainly for general industrial and agricultural applications.

Table 4-1 summarizes the applications of stationary reciprocating engines by fuel category. It shows the average rated power of engines in each fuel use category and gives the estimated energy production in kwhr/yr and shows that natural gas-fueled engines account for 70 percent, diesel and dual-fuel engines account for 20 percent, and gasoline engines produce 10 percent, of total reciprocating IC engine stationary energy production. The energy production estimates in Table 4-1 are based on average power, load factors, operating hours (duty cycles), and engine population data for engines in each category.[3]

4.2 EMISSION SOURCES

CO is emitted in internal combustion engine exhaust due to incomplete combustion. CO formed in the combustion process is converted to CO_2 by combustion with oxygen at temperatures above $625^{o}K$ ($1160^{o}F$). But conversion of CO to CO_2 is inhibited if there is insufficient oxygen present during or after combustion (fuel-rich combustion zones), or if the combustion products cool to temperatures below $625^{o}K$ ($1160^{o}F$) before CO oxidation is complete.

TABLE 4-1

APPLICATIONS OF STATIONARY RECIPROCATING IC ENGINES AND ENERGY PRODUCTION BY FUEL USE CATEGORY[a]

ENGINE APPLICATIONS BY FUEL USE	AVERAGE POWER (kW)	AVERAGE POWER (hp)	ENERGY PRODUCTION (10^6kWhr/yr)	ENERGY PRODUCTION (10^6 hp-hr/yr)	PERCENT OF TOTAL IC ENGINE ENERGY PRODUCTION
Diesel					
Oil and gas transport	1,500	2,000	3,581	4,800	
Oil and gas well drilling	260	350	1,556	2,086	
Electric generation	1,900	2,500	1,611	2,160	
Generator sets	55-560	75-750	4,830	6,475	
General industrial and agricultural (water supply, construction, marine use, pumps, welders, and compressors)	37-560	50-750	8,303	11,130	
TOTAL			19,881	26,651	15
Dual Fuel					
Oil and gas transport			1,662	2,228	
Electric generation			4,476	6,000	
TOTAL			6,138	8,228	5
Natural Gas					
Agricultural	75	100	12,729	17,063	
Oil and gas well pumps, drilling and secondary recovery	11-260	15-350	12,578	16,860	
Oil and gas plant processing	560	750	14,323	19,200	
Oil and gas industry utility compressors	560-1,500	750-2,000	49,385	66,200	
Electric generation	75-220	100-300	1,057	1,417	
General industrial (shaft power, air and water supply)	60-1,500	80-2,000	4,042	5,419	
TOTAL			94,114	126,159	70
Gasoline					
Agricultural machinery and irrigation	75-200	100-300	2,014	2,700	
General industrial (small generator sets, compressors, and welders)	41	55	5,334	7,150	
Construction	110	150	1,119	1,500	
Small (<15 hp) engines	3.1	4.2	4,935	6,615	10
TOTAL			13,402	17,965	

[a] 1974 Data

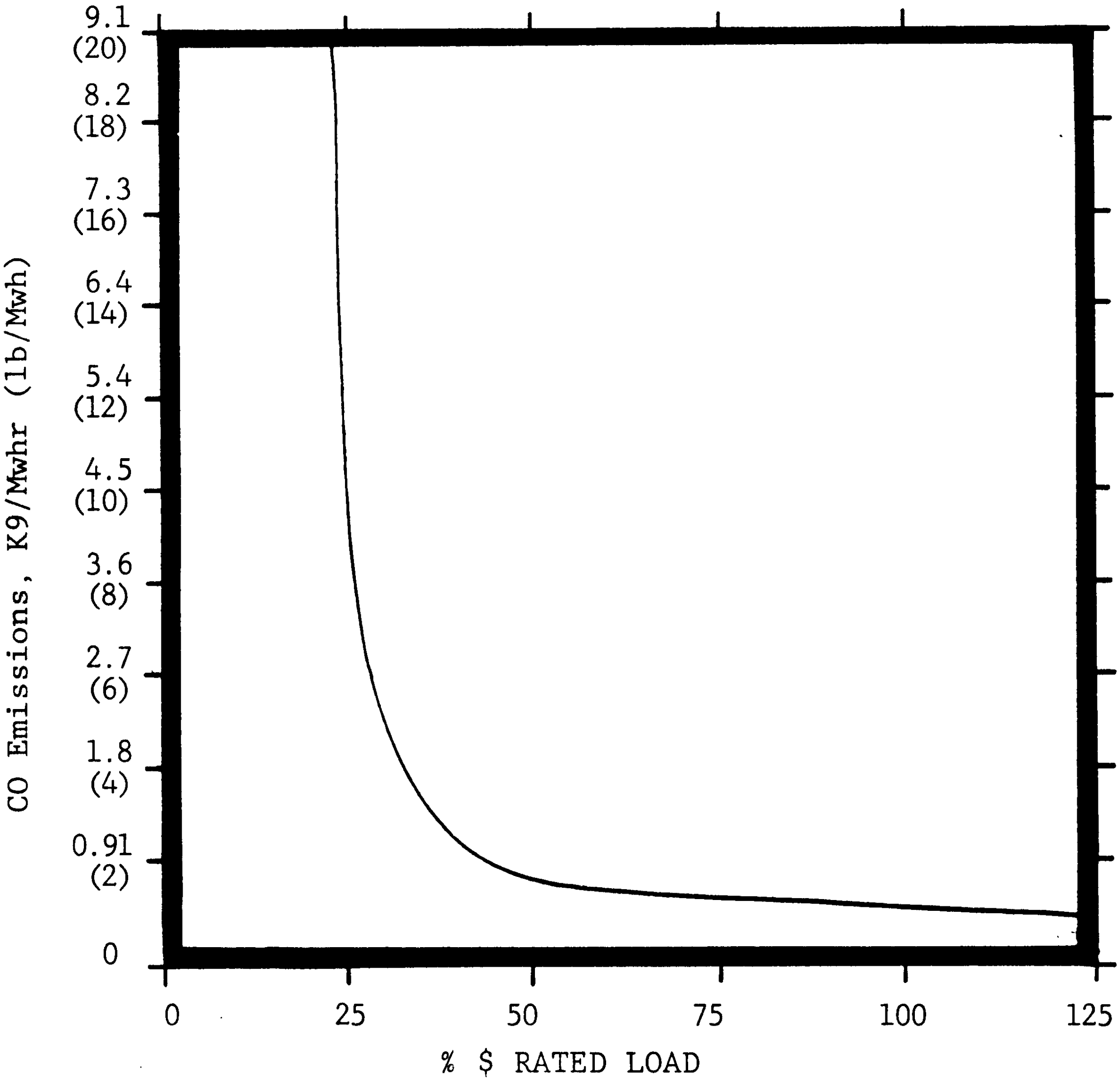
SOURCE: Reference 3

CO emission rates from gas turbines are extremely low above 50% of rated power. CO emission rates from reciprocating internal combustion engines are quite variable. The rates depend on both engine design and how the engine is operated. Important design factors include the number of strokes per power cycle, combustion chamber design, the methods of air charging (aspirated, turbocharged, blower-scavenged), and the method of fuel charging (direct and indirect injection and carburetion). Significant operating variables include fuel type, ignition, air/fuel ratio, engine speed and load, and maintenance practices.

The following sections discuss the effects of engine design and operating variables on CO emissions from gas turbines, spark ignition, and compression ignition engines. Mass emission rates are given for specific engine designs, sizes, and fuels at rated and reduced load and speed. Then average emission factors are presented, and these are used to estimate total nationwide emissions of CO from stationary engines.

4.2.1 Gas Turbine Engines

CO emissions from gas turbine engines, used in electric utility service, expressed in terms of energy, are shown to be very low when the gas turbine is operated under load, as shown in Figure 4-1. It has been postulated that the average load factor for gas turbine engines during operation is about 86.8 percent based on 1196 hours of operation per year, or about 4.8 hours per operating day. It is further assumed that time spent at off-design conditions includes 15 percent at zero load, and 2 percent each at 25 percent, 50 percent and 75 percent load. Then the percentages of operating time at



Source: Reference 4

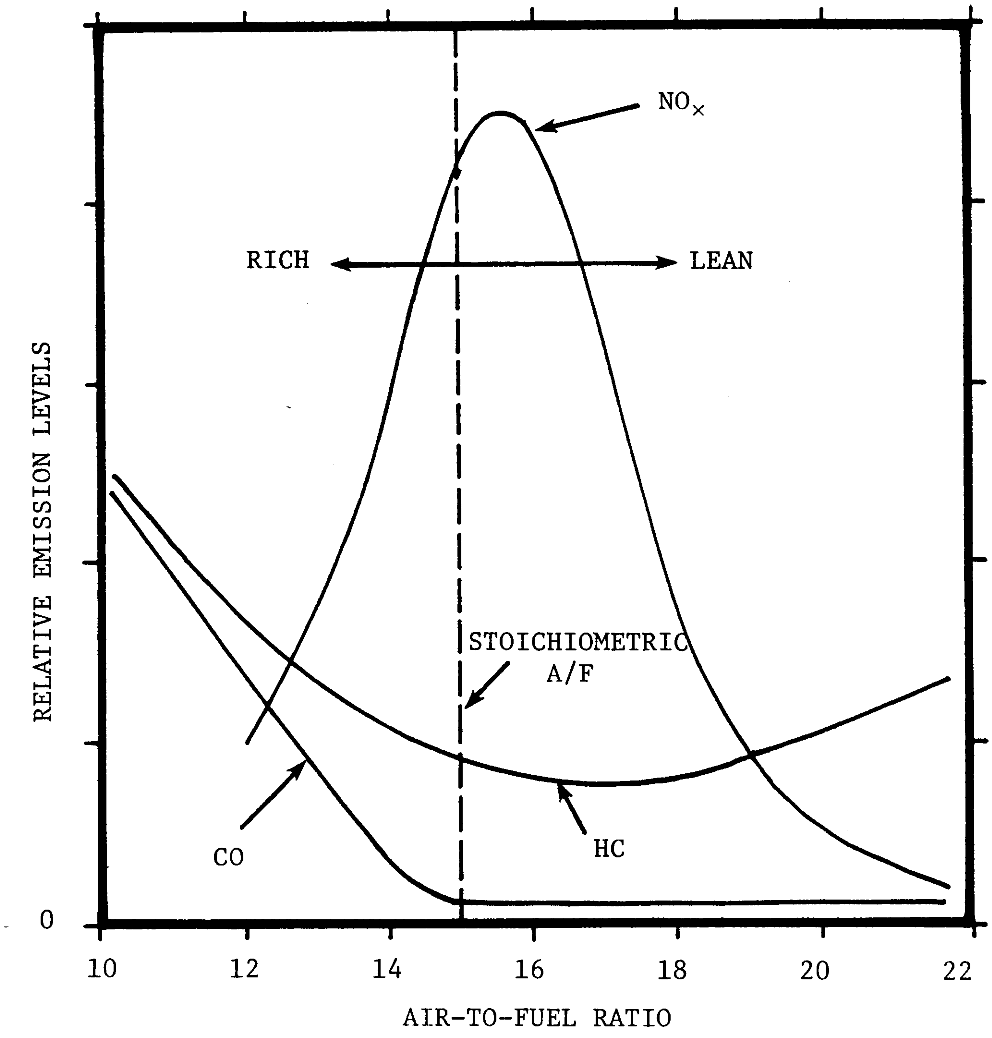
FIGURE 4-1. SPECIFIC EMISSIONS OF CO AS A FUNCTION OF LOAD FOR GAS TURBINE-POWERED GENERATORS, COMPOSITE OF SEVERAL MAKES AND MODELS rated load (100 percent) and peak load (assumed to be 125 percent of rated load) can be calculated to produce an 86.6 percent load factor. These percentages turn out to be 19 percent at peak and 60 percent at rated load. CO emission factors developed for electric utility gas turbines are presented in Section 4.3.

4.2.2 Spark Ignition Engines

Spark ignition engines burn gasoline or natural gas, and CO emissions from gasoline engines are an order of magnitude higher than those from gas engines. The air/fuel (A/F) ratio of the combustible mixture is the most important variable. Figure 4-2 shows the effect of the air/fuel ratio on NO_x, HC, and CO emissions from gasoline engines.[3] It shows that when the air/fuel ratio is adjusted to produce low engine out CO emissions, the NO_x emissions produced by the engine can range from relatively high to relatively low values.

Since gaseous fuels typically allow stable combustion at leaner air/fuel ratios, the CO emissions from gaseous fueled spark ignition engines are considerably lower than they are from gasoline-fueled spark ignition engines.

Table 4-2 summarizes data on CO emissions from heavy duty, 4-stroke, naturally aspirated gasoline engines and medium and large gas engines of different designs.[2] It shows the effects of engine design, fuel type, and air/fuel ratio on emission rates at rated loads. Emissions are given for continuous duty (steady state) operating conditions and as composite (modal) values. The composite values are the result of standard test cycles at specified load/speed modes of operation.



Source: Reference 3

FIGURE 4-2. EFFECT OF AIR/FUEL RATIO ON EMISSIONS FROM A GASOLINE ENGINE

TABLE 4-2

CO EMISSIONS FROM SPARK IGNITION RECIPROCATING ENGINES AT RATED LOAD

	RATED				AVERAGE SPECIFIC MASS EMISSIONS				
					Continuous Duty			Composite	
ENGINE DESCRIPTION	SPEED (RPS)	POWER (bhp)	POWER (kW)	FUEL	(G/kWhr)	(g/hp-hr)	(air/fuel ratio)	(g/kWhr)	(g/hp-hr)
4-stroke, NA, heavy-duty 6 cylinder	38.3	89	66	Gasoline	10.2	7.6	16.0	62.0	46.2
4-stroke, NA, heavy-duty 6 cylinder	38.3	58	43	Gasoline	33.7	25.1	14.7	64.1	47.8
4-stroke, NA, heavy-duty 8 cylinder	38.3	122	91	Gasoline	14.1	10.5	15.6	62.8	46.8
4-stroke, NA, heavy-duty 8 cylinder	38.3	125	93	Gasoline	66.4	49.5	14.7	120.4	89.8
4-stroke, NA, heavy-duty 8 cylinder	38.3	82	61	Gasoline	10.5	7.8	15.2	48.0	35.8
4-stroke, NA, heavy-duty 8 cylinder	38.3	95	71	Gasoline	47.6	35.5	14.4	40.8	30.4
4-stroke, NA, heavy-duty 8 cylinder	38.3	74	55	Gasoline	27.4	20.4	14.8	60.8	45.2
4-stroke, NA heavy-duty 8 cylinder	38.3	77	57	Gasoline	38.5	28.7	14.7	41.6	31.0
4-stroke, NA, 12 cylinder	15	1,200	895	Gas	--	--	--	7.8	5.8
4-stroke, TC, 8 cylinder	15	1,100	820	Gas	--	--	--	0.9	0.7
2-stroke, TC, 8 cylinder	5.5	1,600	1,194	Gas	0.2	0.2	--	--	--
2-stroke, TC, 8 cylinder	4.2	2,000	1,492	Gas	0.4	0.3	24.8	--	--
4-stroke, TC, 8 cylinder	--	--	--	Gas	0.3	0.2	21.0		

NA = Naturally aspirated
TC = Tubocharged

Source: Reference 2

While detailed emission data for smaller gasoline engines are not included in Table 4-2, average emission factors are presented later in this section.

4.2.3 Compression Ignition Engines

CO is formed by the same mechanisms in compression ignition engines as in spark ignition engines, but in compression ignition engines fuel is injected independently of air so fuel/air mixtures are more heterogenous. Fuel distribution can be controlled by injector design, and thus wall quenching effects can be minimized. Compression ignition engines are usually unthrottled and are designed to operate fuel lean (high excess air) so CO emissions are relatively low.

CO emissions from compression ignition engines are more clearly dependent on engine design and variations in emission rates are quite large. The lowest CO emissions are produced by large, low speed engines, and smaller engines usually have higher emission rates. Divided chamber turbocharged diesel engines produce the lowest emissions. Table 4-3 summarizes data on CO emissions from compression ignition diesel engines of different designs and sizes at rated conditions.[4] Average emissions vary from 0.3-14.6 g/kwhr (0.2 to 10.9 g/hphr) depending on engine design.[2]

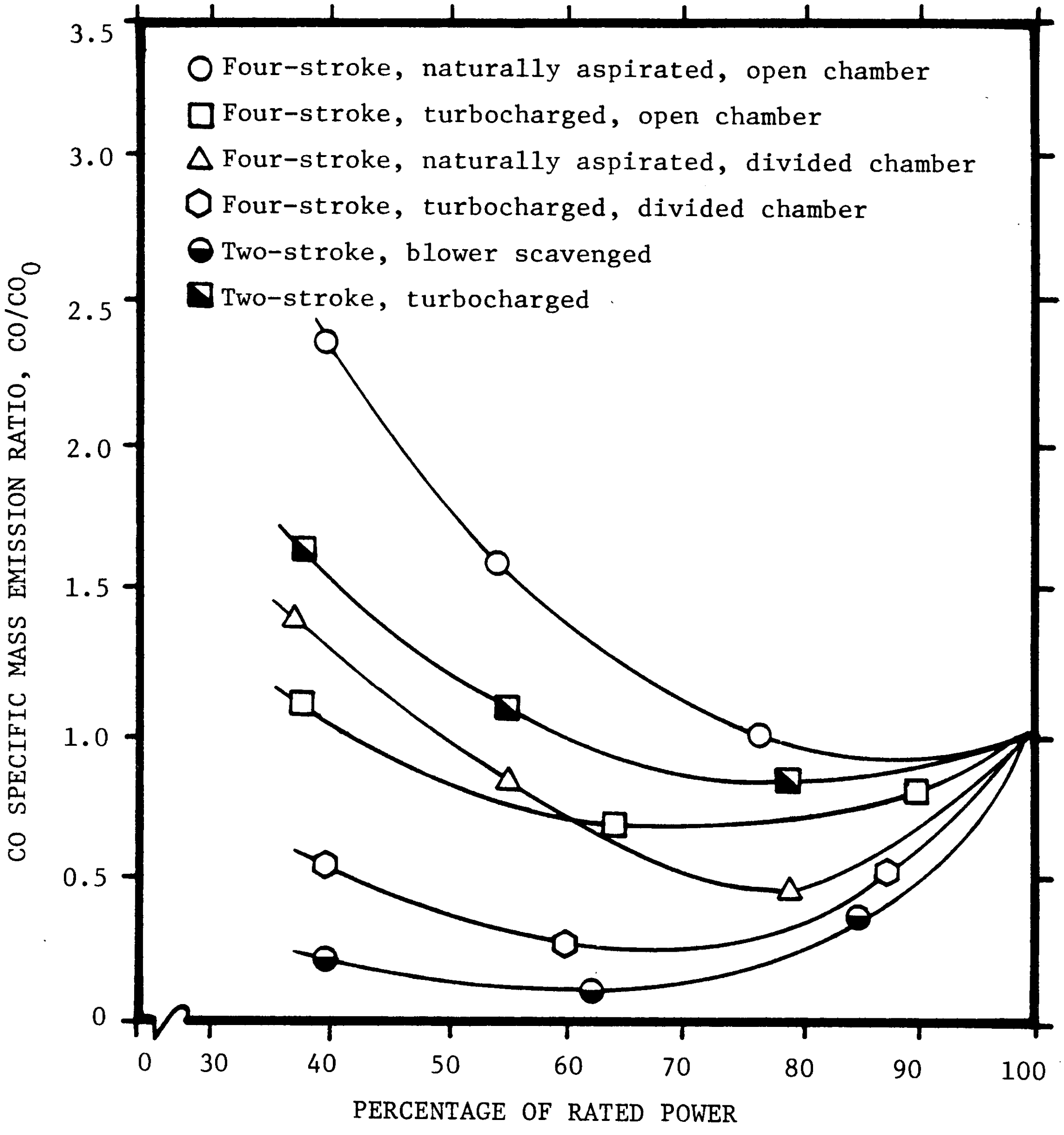
Emissions from compression ignition engines are dependent on engine load and speed. Figure 4-3 shows normalized data variations in CO emissions against engine load at rated speed.[2] The data are expressed in terms of CO/CO_0 as a percent of rated power (mass emissions at reduced power output divided by

TABLE 4-3

CO EMISSIONS FROM COMPRESSION IGNITION RECIPROCATING ENGINES AT RATED CONDITIONS

		CO CONCENTRATION (ppm)		MASS EMISSIONS			
				Average		Range	
ENGINE DESIGN	SIZE	AVERAGE	RANGE	(g/kWhr)	(g/hp-hr)	(g/kWhr)	(g/hp-hr)
4-stroke, NA, open chamber	Medium	1,630	540-5,300	8.7	6.5	3.0-19.6	2.2-14.6
	Large	--	--	5.6	4.2		
4-stroke, TC, open chamber	Medium	680	530-1,000	4.6	3.4	3.5-7.0	2.6-5.2
	Large	--	--	3.5	2.6	1.5-6.0	1.1-4.5
4-stroke, NA, divided chamber	Small (light duty)	1,430	830-2,025	9.8	7.3	4.4-12.2	3.3-9.1
4-stroke divided chamber	Medium	118	62-200	0.8	0.6	0.4-1.2	0.3-0.9
2-stroke, BS	Medium ("mobile")	806	585-1,135	7.2	5.4	4.8-9.5	3.6-7.1
2-stroke, TC	Large Low-speed Stationary	--	--	2.8	2.1	2.1-4.0	1.6-3.0

Source: Reference 2



SOURCE: Reference 2

FIGURE 4-3. DIESEL ENGINE PART-LOAD CARBON MONOXIDE EMISSIONS

emissions at full load) for six engine designs. In general, CO emissions decrease as load is reduced, but they tend to increase as the load is reduced to less than about 60 percent of rated power. When engine speed is reduced as well as load, CO emission rates can be reduced by as much as 50 percent.[3]

4.3 EMISSION FACTORS AND NATIONWIDE CO EMISSIONS

4.3.1 Gas Turbine Engines

Emission factors developed for electric utility gas turbines are presented in such a form as to yield mass emissions in pounds of mass per unit time.[4] CO emission factors are assumed to be uniform for the different types of turbines because of the limited amount of information that is available. Factors for CO are found in Table 4-4.

TABLE 4-4

COMPOSITE CO EMISSION FACTORS FOR THE 1971
POPULATION OF ELECTRIC UTILITY GAS TURBINES ON A FUEL BASIS

	GRAMS PER CUBIC METRE ($lb/10^6$ ft^3) gas	GRAMS PER LITRE ($lb/10^3$ gal) oil
Composite E.F.	1.84 (115)	1.85 (15.4)

Source: Reference 4

Other useful emission factors for electric utility gas turbines are shown in Table 4-5. These factors can be used to estimate nationwide CO emissions by multiplying the composite emission factor and the total rated capacity (MW) of all U.S. gas turbines and assuming both gas and oil-fueled turbines operate 75 percent of the time. On a national basis, electric utility turbine sources account for less than 1/2 of 1% of the CO contribution from all sources. Although CO emissions from electric utility turbines are not a large part of the national or even regional impact, this source of CO can be a major source in urban or heavily populated areas and therefore may require CO control measures.

TABLE 4-5

COMPOSITE CO EMISSION FACTORS FOR THE 1971 POPULATION OF ELECTRIC UTILITY GAS TURBINES

Electrical Output % Rated Power	CO Emissions Kg/Hr per MW Rated Capacity (lb/hr per MW Rated Capacity)	Weighting Factor	Weighted CO Emissions Kg/Hr per MW (lb/hr per MW Rated Capacity)
0*	3.9 (8.6)	0.15	.59 (1.29)
25	1.5 (3.2)	0.02	0.03 (0.06)
50	0.4 (0.8)	0.02	0.01 (0.02)
75	0.4 (0.9)	0.02	0.01 (0.02)
100	0.5 (1.0)	0.60	0.27 (0.60)
125	0.5 (1.0)	0.19	0.09 (0.19)
		1.00	1.00 (2.18)
Composite E.F.			

Source: Reference 4

*Spinning reserve

4.3.2 Reciprocating Internal Combustion Engines

CO emissions from reciprocating engines can vary from less than one to hundreds of g/kwhr depending on engine design, operating conditions, and fuel. Engine population data are available by fuel and rated power, but not by engine design. There are also wide variations in CO emission rates among engines in the same fuel-size categories. All of these factors make it very difficult to define accurate emission factors for reciprocating internal combustion engines. Table 4-6 summarizes "brake-specific" factors.[2,3,5] The emission factors are based on engine application, fuel, and rated power. Annual emissions can be calculated from the product of the emission factor, the number of hours per year of operation, the rated power, and the load factor (output produced divided by output available).

Selected emission factors combined with the data in Table 4-1 were used to estimate nationwide annual CO emissions from stationary reciprocating internal combustion engines. Table 4-7 summarizes the estimate and shows that reciprocating internal combustion engine emissions are 3.6 million metric tons/year (4 million tons/year).

4.4 CONTROL TECHNIQUES

CO control techniques for stationary internal combustion engines are in the developmental stages. There are few techniques currently in routine use to control CO emissions. CO control technology has been developed for mobile applications in response to California and Federal limits on vehicular emissions. The techniques are now being considered for stationary engines. Differences in duty cycles, engine size and weight, and fuels for stationary engines mean that testing is required to demonstrate how the techniques can

TABLE 4-6

CO EMISSION FACTORS FOR RECIPROCATING INTERNAL COMBUSTION ENGINES

ENGINE TYPE/APPLICATION	SIZE		BRAKE SPECIFIC EMISSION FACTOR		REMARKS
	(kW)	(hp)	g/kWhr	g/hp hr	
Gasoline Engines					
Small, 2-stroke, general utility, lawn and garden	11	15	652	486	50 hr/yr usage, 40% load factor
Small, 4-stroke, general utility, lawn and garden	11	15	374	279	50 hr/yr usage, 40% load factor
Small, 4-stroke general utility, miscellaneous uses	11	15	335	250	50 hr/yr usage, 40% load factor
Farm equipment (wheeled tractor)	34(avg)	45(avg)	192	143	550 hr/yr usage
Farm equipment (non-tractor)	19-110	25-150	292	218	
Heavy duty construction equipment (loaders, tractors, graders, scrapers, off-highway trucks)	110	150	190-271	142-202	740-2000 hr/yr usage
Industrial engines (power generation, pumps, well drilling, forklifts)	15-190	20-250	267	199	Aggregate value applicable to population, not individual unit
Diesel Engines					
Farm equipment (wheeled tractor)	34(avg)	4k(avg)	4.48	3.34	550 hr/yr usage
Farm equipment (non-tractor)	19-110	25-150	5.47	4.08	550 hr/yr usage
Heavy duty construction equipment (loaders, tractors, graders, scrapers, off-highway trucks)	37-180	50-240	2.41-5.90	1.80-4.40	740-2000 hr/yr usage
Industrial engines (power generation, pumps, well drilling, forklifts)	34-450	45-600	4.06	3.03	Aggregate value applicable to population, not individual unit
Gas Engines					
Average for all designs and sizes			1.9	1.4	

Source: Reference 5

TABLE 4-7

ESTIMATED 1975 NATIONWIDE CO EMISSIONS FROM INSTALLED RECIPROCATING IC ENGINES

FUEL	RANGE OF RATED POWER (kW)	(hp)	EMISSIONS 10^3 Metric tons/yr (10^3 tons/yr)
Diesel	15-75	20-100	30.7 (33.8)
	76-370	101-500	47.6 (52.5)
	>370	>500	16.9 (18.6)
Subtotal			95.2 (104.9)
Natural Gas	<370	<500	113.0 (125.0)
	>370	>500	242.0 (267.0
Subtotal			355.0 (392.0)
Dual Fuel	All	All	21.1 (23.3)
Subtotal			21.1 (23.3)
Gasoline	<11	<15	1940.0 (2140.0)
	11-74	15-99	856.0 (994.0)
	>75	>100	328.0 (362.0)
Subtotal			3124.0 (3446.0)
TOTAL			3595.3 (3966.2)
Percent of all sources			3.4

Source: Reference 3

be successfully transferred. Stationary engines do not have the space and weight limitations of mobile engines. Since they usually operate at steady-state conditions, it is easier to optimize some operating and design parameters for emission control.

Selection of control techniques for internal combustion engines is a very complex problem. Engine size and design, fuel, and duty cycle as well as the desired level of reduction must be considered. The effects of control methods on fuel consumption, engine maintenance requirements, durability of engine components, performance, and emissions of other pollutants such as NO_x, hydrocarbons, and fine particulates are also important.

In general, there are four ways to reduce CO emissions from stationary reciprocating internal combustion engines: exhaust gas treatment to oxidize CO to CO_2; adjustments to the fuel/air mixture controls; replacement of the engine with alternative engines; and use of alternative fuels. This general discussion of control methods complements the more detailed presentation in Chapter 3.

4.4.1 Oxidation of CO in the Exhaust Gas

Exhaust manifold air injection, thermal reactors, and catalytic converters all control CO emissions by oxidizing CO in the exhaust to CO_2. The gas temperature, oxygen concentration, catalyst parameters and CO concentration are the important operating variables. Secondary air injection and temperature control are often required. Two kinds of thermal reactors have been developed for automotive (gasoline spark ignition) engines: the Rich Thermal Reactor (RTR) for fuel rich air/fuel ratios and the Lean Thermal Reactor (LTR) for lean ratios. The thermal reactor is a container which, by its size and configuration, increases the residence time and turbulence of exhaust gases, thereby providing a chamber for the high-temperature oxidation reaction. High temperatures are maintained by the exothermic oxidation of CO and HC in the exhaust gas[2]. The rich thermal reactor operates at temperature from 870 to 1040°C (1600 to 1900°F) and is designed for fuel rich operation. At rich air/fuel ratios of 11-12 to 1, NO_x emissions are reduced to less than 6 g/kwhr (4.5 g/hphr), but fuel consumption penalties are incurred. Secondary air injection is normally injected into the thermal reactor for complete oxidation, and construction materials such as Inconel 601 are needed for the inner core, baffles and port liners. Temperature control devices are required to protect the reactor construction materials against overtemperature.

The lean thermal reactor operates at higher air/fuel ratios (17-19 to 1) and lower operating temperatures, 760-870°C (1400 to 1600°F), than the rich thermal reactor. Secondary air-injection is not usually required and construction materials have less severe durability requirements than do the materials for rich thermal reactors. Oxidation catalysts and 3-way catalysts are being used extensively in the control of CO from automotive engines. This CO control strategy can be equally effective in the control of CO from stationary engine sources. Recent literature describes a patented platinum catalyst on a ceramic honey comb support that has withstood 50,000 hours of stationary engine testing.[6] The catalytic converter has also been used for small Diesel, LP gas, and gasoline engines in sizes up to 13.1 litres (800 cubic inches) displacement and is applicable to 2- and 4-cycle naturally aspirated or turbocharged engines. Applications include Diesel powered mining and tunneling equipment, locomotives, loaders, forklift trucks operated in enclosed spaces, and electric generators located near airconditioning intakes. For oxidation catalysts to be an effective means of controlling CO and HC emissions, the engine must be properly tuned and unleaded fuel must be used. Also, the control system should ideally be adjusted to preclude the formation of sulfate emissions which can be formed in the catalyst due to excess oxygen in the exhaust gases and sulfur content of the fuel. Alternatively, sulfur can be removed from the fuel. In the case of 3-way catalysts, rich mixtures are conducive to the formation of HCN and ammonia.

Air injection into the exhaust manifold can reduce CO emissions by a factor of 55 percent from baseline emissions on some engines with modifications to the air/fuel ratio, compression ratio, and spark ignition timing schedule.[2]

4.4.2 Design Changes and Operating Adjustments

The air/fuel ratio is the operating variable that determines CO emissions, and it has a significant effect on NO_x emissions. Operation at air/fuel ratios that produce low CO emissions can produce high or low NO_x emissions depending on the exact value of the air/fuel ratio used. Since NO_x emissions from stationary reciprocating internal combustion engines are considered more of a problem than CO emissions, design and operating changes are expected to be made in these sources primarily for NO_x control. Care must be taken to ensure that the entire emission control system provides adequate control of all emissions that need to be controlled. This sometimes leads to more sophisticated systems. Derating, turbocharging, and improved fuel injection nozzles can be used to control CO emissions from compression ignition engines. The addition of a turbocharger is normally used to increase specific power output but it also can increase the air/fuel ratio in the power modes of operation. This usually improves specific fuel consumption but also causes an increase in NO_x emissions. Retarded injection timing (diesel) and/or intercooling the boosted inlet air charge can be used to offset the NO_x penalty. Improved diesel fuel injectors (e.g., low sac nozzles) can be used to reduce CO and HC emissions but, again, NO_x emissions may increase due to more efficient and higher temperature combustion.

Measures that could be used to increase the air/fuel ratio for gasoline spark ignition engines include charge homogenation and air/fuel stratification. Both approaches are under consideration and may provide some potential for lowered CO emissions. In general, adjustments to increase the air/fuel ratio for gasoline engines will require design changes to insure a uniform air/fuel mixture in each cylinder and to achieve stable engine operation.

4.5 ECONOMIC, ENVIRONMENTAL, AND ENERGY IMPACTS OF CONTROL TECHNIQUES

The only existing regulations for CO emissions from internal combustion sources are the California and Federal standards for automotive engines (see Chapter 3). As a result of these standards, most CO control technology has been developed for automotive engines. Suggested standards of performance for new stationary engines do not now require CO control so there is little incentive for developing stationary engine CO controls.[6] Catalytic (oxidation) converters are currently marketed for small engines, mostly on wheeled equipment used in enclosed spaces. This is the only example of a CO control technique currently available for application to a "stationary" engine. Some testing has been done, however, to determine the applicability of automotive engine controls to stationary engines.[2]

Since CO control methods for stationary engine sources are still in the developing stages, there is no quantitative information on cost CO reduction efficiencies for controls applied to classes of stationary engines, or environmental and energy impact. The status of development for different control techniques and qualitative information on environmental and energy impacts for new mobile sources are summarized in Chapter 3. Many of these CO control techniques are also applicable to the stationary source powerplants.

Internal combustion engines also produce significant emissions of nitrogen oxides, hydrocarbons, odorous organic compounds, and fine particulates (smoke). Table 4-8 shows that internal combustion engines contribute quite significantly to the nationwide emissions of NO_x, CO, and hydrocarbons.[3] The NO_x and reactive hydrocarbon emissions due to the application of CO control techniques are important because these pollutants participate in oxidant-forming reactions. In developing standards of performance for new internal combustion engines, more emphasis has been placed on controlling NO_x emissions than CO or hydrocarbons. This is relevant because control techniques usually influence the emissions of NO_x and hydrocarbons as well as CO.

TABLE 4-8

PERCENT OF TOTAL 1975 NATIONWIDE EMISSIONS OF NO_x, CO,
AND HYDROCARBONS FOR STATIONARY INTERNAL COMBUSTION ENGINES

	NO_x	CO	TOTAL HYDROCARBONS
Percent of all sources	8.4	3.4	3.8

Source: Reference 3

There are some changes in engine design or operating variables that result in lower CO emissions, but in some cases those reductions are achieved at conditions which produce increased NO_x emissions. Since controlling NO_x emissions from internal combustion engines has a higher priority than controlling CO emissions, there are probably few situations in which CO emissions would be controlled at the expense of increasing NO_x emissions. Consequently, aftertreatment devices such as catalytic systems would appear to be one of the control approaches that would be considered if both NO_x and CO are to be controlled to the lowest levels.

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5. STATIONARY EXTERNAL COMBUSTION SOURCE CONTROL

This chapter describes carbon monoxide emissions and controls from significant stationary combustion sources. Combustion sources discussed include utility and industrial boilers, residential and commercial heaters, and solid waste incinerators. Process descriptions are given in enough detail to indicate where emissions are produced, and emission quantities are estimated for each source. Currently applied control technology and feasible control methods are discussed, as are control efficiencies, energy requirements, costs, and environmental impacts.

5.1 UTILITY AND LARGE INDUSTRIAL BOILERS

This category includes the majority of the utility and industrial electric power generating boilers. The thermal input of boilers in this category ranges from 30 MW (100×10^6 Btu/hr) up to 3500 MW (120×10^8 Btu/hr).

5.1.1 <u>Process Description</u>

Utility and large industrial boilers may be fueled with coal, oil, or gas. The principle distinction between these boilers is the type of fuel fired and the firing mode, although such factors as furnace volume, operating pressure, and configuration of internal heat transfer surface differ as well. Firing mode includes the type of firing equipment, the fuel handling equipment, and the placement of the burners on the furnace walls. The major types of firing modes are:

1. single- or opposed-wall fired,
2. tangentially fired,
3. turbo fired,
4. cyclone fired, and
5. stoker fired.

Each of the major firing modes except stoker fired can be used in boilers burning gas, oil, or pulverized coal. However, the cyclone mode is usually designed to fire coal as the principal fuel.

In single- or opposed-wall fired furnaces, the burners are mounted horizontally on the walls of the combustion chamber. These units can burn gas, oil, pulverized coal, or a combination of these fuels. Opposed-wall firing is used in larger units and capacities generally exceed 1200 MW (4×10^9 Btu/hr) heat input.[1] Turbo fired units are similar to horizontally opposed units except that the burners are set at an angle in the vertical plane. The intermixing of the opposing streams produce highly turbulent conditions and virtually complete combustion takes place below the furnace throat.[2]

Tangential fired units have a furnace characterized by a square cross-sectional shape with burners mounted in two or more corners. The burners are fired tangentially to a small, imaginary circle in the center of the furnace so that the flames exhibit a rotating or spinning motion.[1,2]

In cyclone fired units, fuel and air are introduced circumferentially into a water-cooled cylindrical combustion chamber. Cyclone burners were originally designed to burn crushed, low ash-fusion temperature coals. However, because of difficulties in obtaining suitable low sulfur coals and the inability of this design to adapt to low NO_x operation, cyclone furnaces are no longer being constructed. Many existing cyclone units have been convert to burn fuels other than coal.[2,3]

Vertical fired furnaces were developed for pulverized coal burning prior to the advent of water-walled combustion chambers. These units provide long residence times and burn low volatile content coals such as anth cite. Vertical fired units are no longer sold and relatively few of these units are found in the field.[3]

Stoker-fired boilers are designed to burn solid fuels in a bed. This bed is either a stationary grate through which ash falls, or a moving grate which dumps the ash into a hopper. The two most common types of stoker d signs are underfeed (single and multiple retort) and overfeed (spreader) stokers. In the underfeed designs both fuel and air move in the same relative direction. Rams force the new fuel into the furnace from beneath the fuel bed as ash is pushed aside and collected.[1,3] Spreader stokers are overfeed designs which distribute the fuel by projecting it evenly over the fuel bed. A portion of the coal burns in suspension. The upper limit of spreader stoker size is about 180 MW (600 x 10^6 Btu/hr) heat input.[4] All larger sized units are pulverized coal or cyclone designs. Either pulverized coal or spreader stoker-type units are used in the size range of 30-180 MW (100-600 x 10^6 Btu/hr) heat input depending upon local economics and customer preference.[5]

5.1.2 Process Emission Sources and Factors

The formation of carbon monoxide in boilers and subsequent emission in the flue gas results primarily from the partial oxidation of the fuel. In some cases, however, high temperature dissociation may contribute to the emissions of CO in boiler flue gas, particularly if the unit is being operated above design load. Improperly operated stoker boilers may also emit excessive amounts of CO by the reduction of CO_2. This occurs when the fuel bed is allowed to build too deep, creating a reduction zone where the CO is formed.

Estimates of 1977 fuel consumption were obtained from an inventory of combustion-related emissions from stationary sources, published by the EPA.[1] These estimates were based in part on data contained in the National Emissions Data Service file and agree with data obtained from other references.[3,4] CO emissions were estimated from the fuel data using AP-42 emission factors as listed in Table 5-1.[6] EPA estimates of 1977 CO emissions for utility boilers and large industrial boilers are given in Table 5-2. The total estimated emissions from both utility and large industrial boilers are 405,600 metric tons/yr (447,200 tons/yr).[7] These sources contribute slightly more than 2 percent of the total estimated CO Emissions from all stationary sources.

5.1.3 Control Techniques

Control strategies for reducing CO emissions from utility and large industrial boilers can be divided into two groups:

1) Control strategies which reduce CO concentrations in boiler flue gas, and
2) Control strategies which reduce CO emissions by decreasing boiler fuel consumption through increased unit efficiency.

It should be noted, however, that CO emissions from well-operated units are usually quite low (less than 50 ppm) so that implementation of further controls in many cases offers very little potential for further reduction.[8] The following is a summary of the various control techniques.

TABLE 5-1. CO EMISSION FACTORS FOR UTILITY AND LARGE INDUSTRIAL BOILERS

Application	Emission Factor	ppm CO in Flue Gas (at 3% O_2)
Utility and large industrial boilers - coal (all except stokers)	0.5 kg CO/metric ton (1 lb CO/ton)	48
Utility and large industrial boilers - coal (stokers)	1 kg CO/metric ton (2 lb CO/ton)	96
Utility boilers - oil	0.63 kg/10^3 liters (5 lb CO/10^3 gal)	27
Large industrial boilers - oil	0.63 kg/10^3 liters (5 lb CO/10^3 gal)	36
Utility and large industrial boilers - natural gas and process gas	272 kg/10^6Nm^3 (17 lb CO/10^6 scf)	24

Source: Reference 6

TABLE 5-2. SUMMARY OF 1977 NATIONWIDE CARBON MONOXIDE EMISSIONS FROM UTILITY AND LARGE INDUSTRIAL BOILERS

Fuel Type	CO Emissions 10^3 metric tons/yr	 10^3 tons/yr
Anthracite Coal		
Electric Utilities	0.6	0.7
Industrial Boilers	0.5	0.5
Bituminous Coal and Lignite		
Electric Utilities	212.8	234.6
Industrial Boilers	26.8	29.5
Residual Oil		
Electric Utilities	50.7	55.9
Industrial Boilers	24.0	26.5
Distillate Oil		
Electric Utilities	5.6	6.2
Industrial Boilers	9.5	10.5
Natural Gas		
Electric Utilities	22.7	25.0
Industrial Boilers	52.4	37.8
TOTAL	405.6	447.2

Source: Reference 7

5.1.3.1 Automatic Excess Air Rate Control

In normal boiler operation, it is often necessary to operate at excess air rates somewhat higher than what is necessary for complete combustion. This is to provide a "cushion" against minor variations in process conditions such as fuel heating value, steam pressure, ambient temperatures, etc. Without such a cushion, fluctuations in the air/fuel ratio can result in periodic smoke and/or high CO emissions.[8] By employing automatic excess air control, the boiler can be operated at low excess air rates, resulting in less fuel consumption and reduced NO_x emissions, while still assuring that CO emissions are held to a minimum.

5.1.3.2 Proper Firing Rate

Components of the combustion system should be chosen to handle any future increases in load requirements. Firing in excess of design capacity can result in premature cooling of combustion gases by decreasing the residence time of these gases within the combustion zone. A similar quenching effect is observed if the flames are allowed to impinge on any relatively cold surfaces within the combustion chamber. Cooling of the combustion gases by these mechanisms can result in increased emissions of smoke and CO.

5.1.3.3 Burner Maintenance

Damaged or clogged burners can result in high CO emissions by disturbing proper air/fuel distribution. Both proper installation and maintenance of burners and other combustion equipment is required for clean and efficient operation and minimum CO emissions.

5.1.3.4 Reduced Fuel Consumption

Devices for improving the thermal efficiency of a boiler system, such as added insulation, low excess air burners, air preheaters, soot blowers, and load management techniques, can be implemented to reduce CO emissions. A decrease in fuel consumption will usually result in a proportional decrease in CO emissions.

5.1.4 Cost of Controls

Many of the CO control techniques mentioned above involve operations or maintenance-related functions, such that capital cost requirements are low or negligible. In many cases increased maintenance costs due to CO control efforts are offset by fuel savings through more efficient operation.

Sophisticated combustion control systems, such as the automated excess air control mentioned above, can be quite expensive to implement. Costs vary substantially depending on the complexity of the system. However, a control system which controls excess air rates at a minimum will result in overall fuel savings, which can help offset high first costs.

5.1.5 Impact of Controls

5.1.5.1 Emission Reduction

Total CO emissions from utility and large industrial boilers are estimated at 405,600 metric tons/yr (447,200 tons/yr).[7] The potential for significant reduction of these emissions by the applications of additional CO control techniques is not large. Factors which contribute to this are:

1. CO emissions from most utility and large industrial boilers are quite low (generally lower than 50 ppm in the flue gas).[8]
2. Oil and coal-fired units will usually emit smoke or soot when the amount of excess air is decreased. Conditions which result in smoke formation are avoided, resulting in corresponding low CO levels.[3]

3. Several of the common NO_x control techniques result in increased CO emissions. In general, a NO_x control method is applied until flue gas CO levels reach 200 ppm. Further application is then curtailed.[3] Table 5-3 illustrates the change in CO emissions which results from application of NO_x control measures to several boilers.
4. CO emissions from coal-fired units are usually higher than those from oil or gas-fired units.[6] Many utilities are converting their oil and gas units to coal, reflecting anticipated shortages of these fuels. Hence, CO emissions can be expected to increase accordingly.

5.1.5.2 Environment

Reducing CO emissions from combustion sources usually involves techniques which improve combustion. Examples of such techniques include checking oil burners for proper fuel atomization or improved control over excess air levels. These same techniques are also useful in reducing the level of combustible particulates.[9]

Sulfur dioxide emissions are not directly affected by CO control techniques as most all of the sulfur in the fuel exits with the flue gas. There is some evidence, however, which suggests that lowering excess air levels (by using a better combustion control system, for example) can result in reduced sulfate emissions.[3] Total sulfur emissions, though, can be decreased proportionately by any efficiency improving technique which results in lower fuel consumption rates.

TABLE 5-3. REPRESENTATIVE EFFECTS OF NO_x CONTROLS ON CO EMISSIONS FROM UTILITY BOILERS

NO_x Control	Fuel	CO Emissions (ppm at 3% O_2)	
		Baseline	With NO_x Control
Low Excess Air	Natural Gas	14	68
		86	74
		12	61
		8	8
		14	14
	Oil	19	42
		85	53
		15	20
		19	19
	Coal	42	93
		20	60
		24	283
		27	81
		27	225
Staged Combustion	Natural Gas	14	16
		86	67
		12	13
		14	14
	Oil	19	21
		85	85
		15	21
		28	37
	Coal	24	20
		27	26
		17	40
		31	45
Flue Gas Recirculation	Natural Gas	175	65
	Oil	21	9

Source: Reference 3

5.1.5.3 Energy Requirements

Generally, approaches to CO control involve maximizing fuel efficiency. Consequently, implementation of most CO control measures results in a net fuel savings.

5.2 INDUSTRIAL BOILERS

The industrial boilers discussed in this section differ from the utility and large industrial boilers described in Section 5.1, in that the thermal input of these boilers is smaller [3-30 MW (10-100 x 10^6 Btu/hr)], the designs are less complicated, and the fuels consumed are more varied. In general, operation of industrial boilers is less controlled than that of utility boilers.

5.2.1 Process Description

Industrial boilers with 3-30 MW (10 x 10^6 - 100 x 10^6 Btu/hr) capacities are either field-erected or package units.[3] Usually, field-erected units have larger capacities and are similar in design to the boilers described in Section 5.1.

Packaged boilers (shipped complete with fuel-burning equipment) are mainly watertube or firetube designs, although other types such as cast iron or shell designs are occasionally used in applications where low pressure steam is all that is needed. In watertube boilers, hot gas passes over water- or steam-filled tubes which line the combustion chamber walls (Figure 5-1). In firetube boilers, hot gas flows directly through tubes which are submerged in water (Figure 5-2).

Most packaged boilers with capacities greater than 8.8 MW (30 x 10^6 Btu/hr) are watertube boilers.[3] Upper pressure limits on firetube boilers range

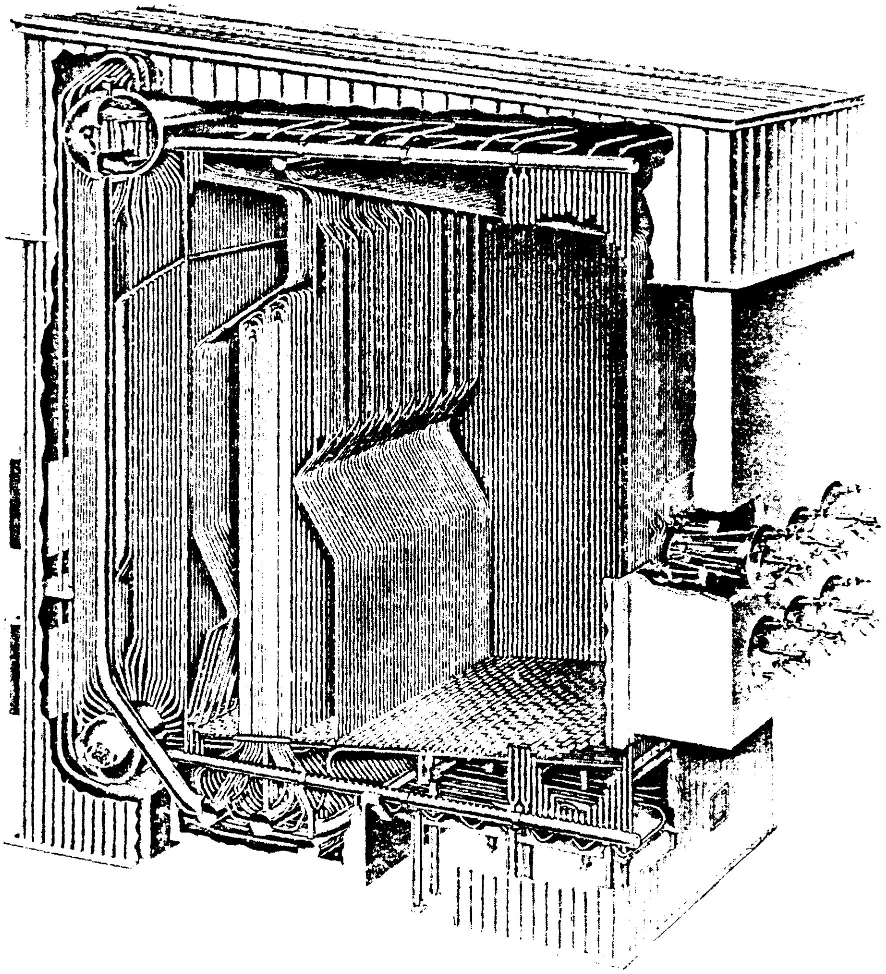


FIGURE 5-1. WATERTUBE BOILER

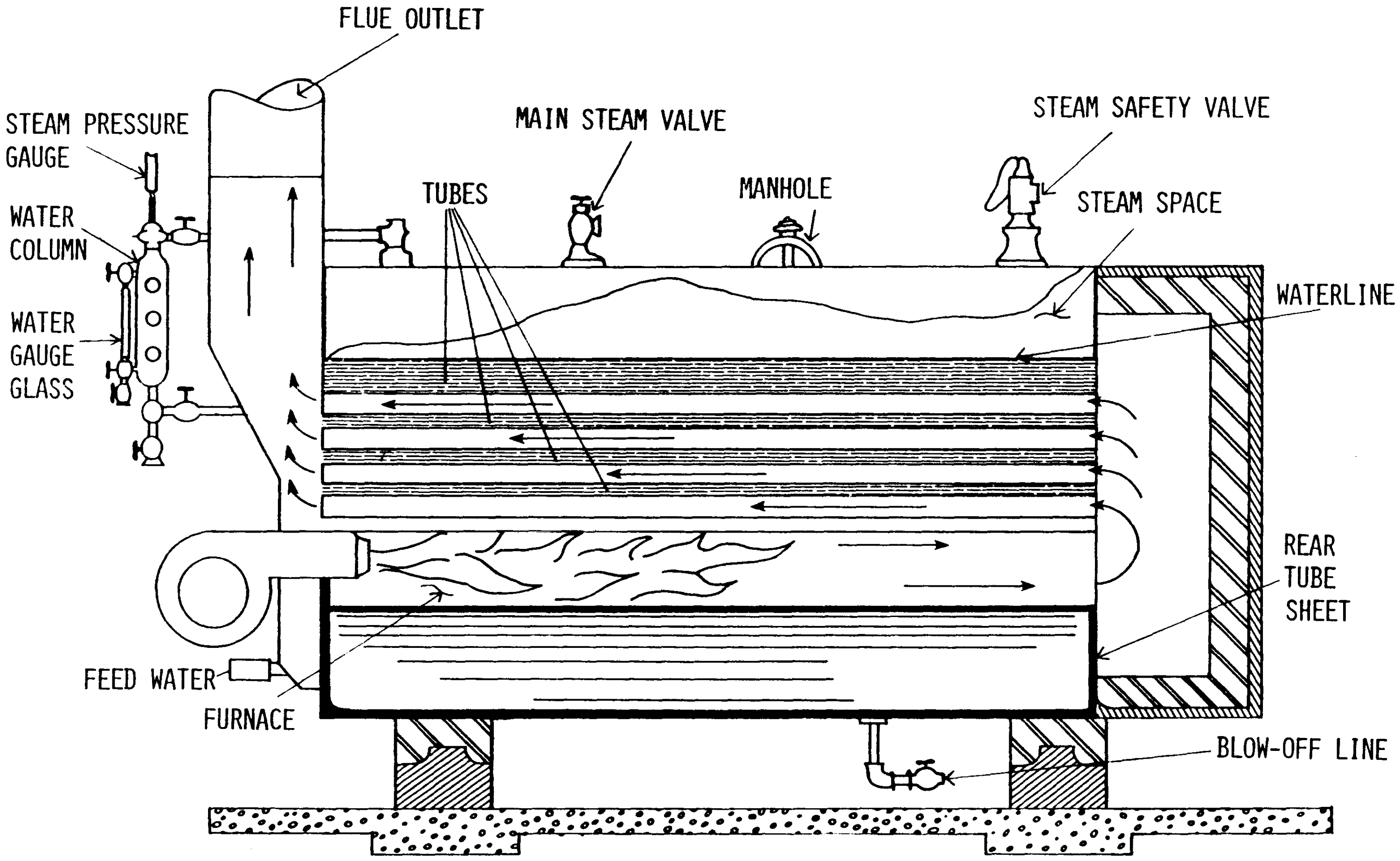


FIGURE 5-2. FIRETUBE BOILER

from 1.1 - 1.8 megapascals (150-250 psig).[5] Small watertube boilers have been built for operation at up to 4.2 megapascals (600 psig).[5]

Packaged boilers of both types are primarily single-burner fired, using either natural gas or fuel oil. About 15 percent of packaged boilers were reportedly stoker-fired in 1975.[3] Boiler firing modes are discussed in greater detail in Section 5.1.1.

5.2.2 Process Emission Sources and Factors

The factors that contribute to carbon monoxide production in utility boilers (Section 5.1.2) also contribute to CO formation in industrial boilers. Although industrial boilers have less sophisticated combustion monitoring systems than larger utility boilers, carbon monoxide emissions may be slightly less because industrial boilers are generally fired with greater amounts of excess air.[3]

Reported carbon monoxide emission factors for industrial boilers are given in Table 5-4.[6] The total 1977 carbon monoxide emissions from both large and small industrial boilers were estimated at 117,800 metric tons (129,900 tons).[7] Emissions from industrial boilers contributed approximately 0.8 percent of the carbon monoxide emitted from stationary sources in 1977.[7]

5.2.3 Control Techniques

Methods of controlling carbon monoxide emissions from industrial boilers are similar to those discussed for utility boilers in Section 5.1.3.

5.2.4 Cost of Controls

The carbon monoxide control techniques applicable to industrial boilers are based primarily on maintenance and operational procedures. Capital

TABLE 5-4. CARBON MONOXIDE EMISSION FACTORS FOR INDUSTRIAL BOILERS WITH CAPACITIES OF 3-30 MW (10^7-10^8 BTU/HR)

Fuel type	Firing mode	Emission factor
Bituminous coal	Spreader stoker	1 kg/metric ton burned (2 lb/ton)
Anthracite coal	Pulverized, dry	0.5 kg/metric ton burned (1 lb/ton)
	Overfeed stoker	0.5 kg/metric ton burned (1 lb/ton)
Fuel oil, residual	Single-wall burner	0.63 kg/10^3 liters burned (5 lb/10^3 gal)
Fuel oil, distillate	Single-wall burner	0.63 kg/10^3 liters burned (5 lb/10^3 gal)
Natural gas	Single-wall burner	272 kg/$10^6 m^3$ burned (17 lb/10^6 ft^3)
Liquid propane gas	Varies	0.18 kg/10^3 liter burned (1.5 lb/10^3 gal)
Liquid butane gas	Varies	0.19 kg/10^3 liter burned (1.6 lb/10^3 gal)
Wood/bark	Varies	1-30 kg/metric ton burned (2-60 lb/ton)

Source: Reference 6

costs for CO control in these units are therefore negligible. Maintenance costs can possibly be recovered by the fuel savings resulting from more efficient boiler operation. Control costs are discussed in more detail in Section 5.1.4.

5.2.5 Impact of Controls

5.2.5.1 Emission Reduction

Because the potential for carbon monoxide emissions reduction from industrial boilers is small, it is doubtful that the estimated 117,800 metric tons (129,900 tons) of CO emitted per year can be substantially reduced. Contributing factors to this situation are similar to those discussed in Section 5.1.5.

1. Carbon monoxide in the flue gas signifies decreased fuel combustion efficiency. Therefore, most industrial boilers are operated to keep CO emissions at a minimum.
2. Smoke emissions resulting from low excess air firing occur before significant CO emissions are produced. Operating with too low excess air can therefore be easily diagnosed and corrected before CO emissions become excessive.

5.2.5.2 Environment

Environmental effects of carbon monoxide emissions reduction from industrial boilers are similar to the effects described for utility boilers in Section 5.1.5. However, specific data regarding the trade-offs between NO_x and CO controls were not available for industrial boilers.

5.2.5.3 Energy Requirements

Excessive carbon monoxide emissions are an indication of inefficient boiler operation and therefore poor fuel usage. The application of CO controls, which generally improve boiler fuel combustion, will result in increased unit efficiency. Specific data to estimate energy savings were unavailable.

5.3 RESIDENTIAL, COMMERCIAL, AND INSTITUTIONAL HEATERS

Small-scale combustion units consume a considerable amount of the total fuel burned in the United States. These combustion sources include forced air, hot water, and steam space heating systems as well as hot water heaters. The majority of these sources are fired with gas and oil although some coal burning equipment, primarily the coal stoker, is still in use.

Total CO emissions from these sources have been estimated at 314,500 metric tons per year (346,700 tons/yr).[7] Residential fuel burning accounts for about 79 percent of this total while the remainder is composed of emissions from the commercial/institutional sector.[3, 6, 10]

5.3.1 Process Descriptions

5.3.1.1 Residential heating

There were an estimated 60 million fuel burning residential heating plants in operation in 1974.[4] These units consumed an estimated 8.2 x 10^{18} Joules/yr (7.8 x 10^{15} Btu/yr) of fuel.[3, 10]

The firing capacity of these units is quite low with maximum firing rates seldom exceeding 117 kilowatts (400,000 Btu/hr).[3] The most common fuels used for residential heating include natural gas and distillate fuel oil which account for roughly 69 and 28 percent, respectively, of the total fuel consumption for this category. The use of coal in residential heating units has been declining since 1945 due to the availability of cleaner, more readily utilized fuels.[11] As a result, coal accounts for less than 3 percent of the total amount of fuel consumed in these units.[3] Small amounts of other fuels including LPG and wood are also used.

5.3.1.2 Commercial and Institutional Heating

Commercial and institutional systems are used for space heating and hot water generation. The equipment consists mainly of oil and gas fired warm air furnaces and firetube boilers.[3] The firing capacities of these units range from 88 kilowatts (300,000 Btu/hr) to 3 megawatts (1×10^7 But/hr).

The total amount of fuel used for commercial and institutional space heating in 1974 has been estimated to be 4.9×10^{18} Joules/yr (4.6×10^{15} But/yr).[3,10] Fuels burned in commercial and institutional heaters include residual and distillate fuel oil, natural gas, and occasionally coal. Residual fuel oil use is generally limited to larger units.

5.3.2 Process Emission Sources and Factors

Carbon monoxide emission factors for small combustion sources are listed in Table 5-5.[6] EPA emission estimates for residential, commercial, and institutional heaters are shown in Table 5-6.

Carbon monoxide is formed as an intermediate product of reactions between carbonaceous fuels and oxygen. If the conditions necessary for complete combustion are not provided, CO will be included in the combustion products.[12] In general, the conditions required for complete combustion are:

TABLE 5-5. CARBON MONOXIDE EMISSION FACTORS FOR RESIDENTIAL, COMMERCIAL, AND INSTITUTIONAL HEATING

Fuel	Emission Factor	
Bituminous coal		
Stokers	5 kg/metric ton	(10 lb/ton)
Hand fired	45 kg/metric ton	(90 lb/ton)
Anthracite coal		
Stokers	0.5 kg/metric ton	(1 lb/ton)
Hand fired	45 kg/metric ton	(90 lb/ton)
Fuel Oil	0.63 kg/10^3 liters	(5 lb/10^3 gal)
Natural gas	320 kg/10^6 Nm^3	(20 lb/10^6 scf)
LPG		
Butane	0.24 kg/10^3 liters	(2 lb/10^3 gal)
Propane	0.23 kg/10^3 liters	(1.9 lb/10^3 gal)
Wood	60-130 kg/metric ton	(120-260 lb/ton)

Source: Reference 6

TABLE 5-6. ESTIMATED 1977 NATIONWIDE CARBON MONOXIDE EMISSION FROM RESIDENTIAL AND COMMERCIAL/INSTITUTIONAL HEATERS

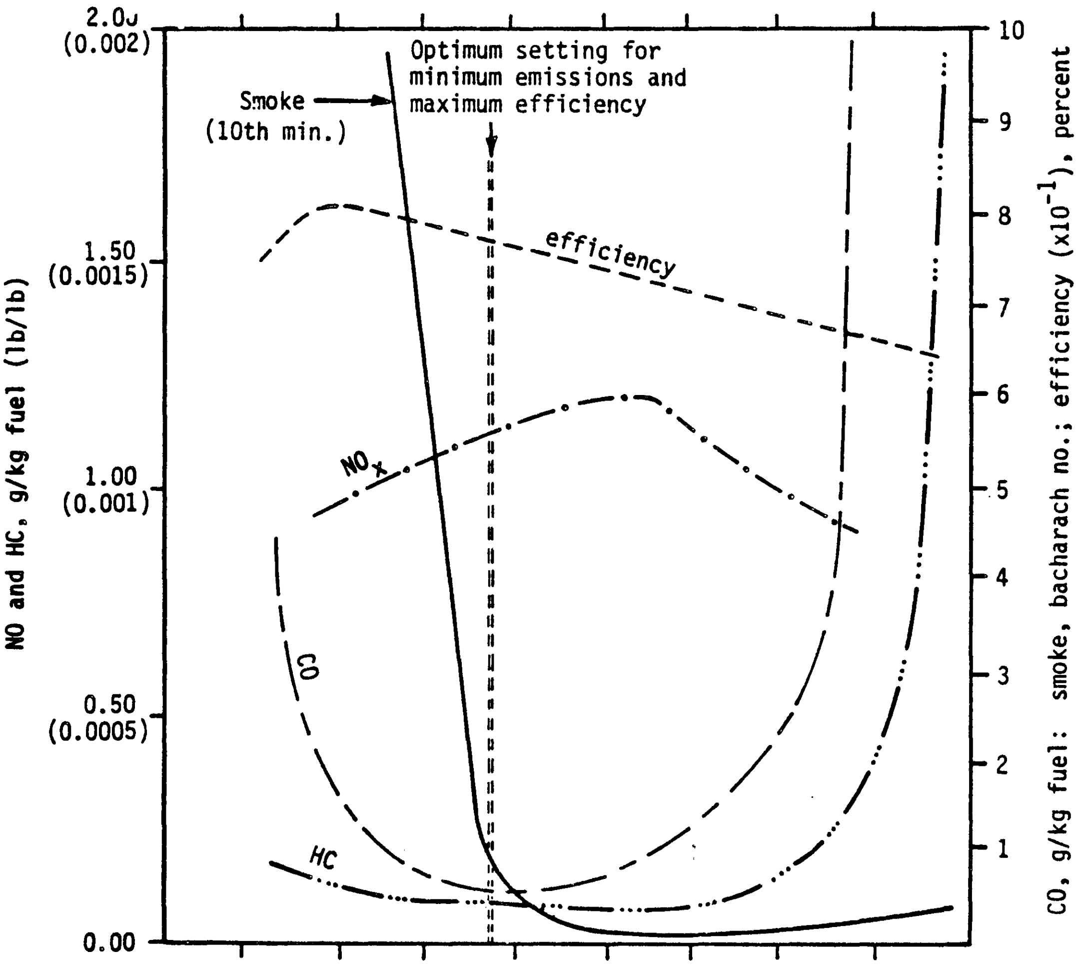
Fuel/Heater Type	CO Emissions metric tons/yr	 tons/yr
Anthracite Coal		
Residential	77.6	85.5
Commercial/Institutional	0.1	0.1
Bituminous Coal and Lignite		
Residential	73.5	81.0
Commercial/Institutional	5.0	5.5
Residual Oil		
Residential	0	0
Commercial/Institutional	20.7	22.8
Distillate Oil		
Residential	38.8	42.8
Commercial/Institutional	17.3	19.1
Natural Gas		
Residential	46.1	50.8
Commercial/Institutional	24.2	26.7
Kerosine		
Residential	4.5	5.0
Liquid Propane Gas		
Residential/Commercial	6.7	7.4
TOTAL	314.5	346.7

Source: Reference 7

1. High combustion temperatures,
2. Proper excess air levels for the fuel being fired,
3. Rapid mixing of the fuel and the combustion air, and
4. Sufficient residence time of the combustion gases within the combustion chamber.

CO emissions are sensitive to the amount of combustion air supplied to the burner. Figure 5-3 shows the general trend of CO, smoke, NO_x, and fuel efficiency as a function of the excess air level for a typical oil burning unit. As excess air is increased from theoretical, emissions of smoke, CO, and unburned hydrocarbons pass through a minimum while fuel efficiency and NO_x emissions pass through a maximum.[3] As indicated in the diagram, proper excess air levels can result in high fuel efficiency and low CO and smoke emissions. At excess air levels below this point, CO and smoke emissions increase because the concentration of oxygen at the flame is too low to permit complete combustion during the residence time provided. Too much excess air results in increasing CO and hydrocarbon emissions because the additional combustion air cools the flame to temperatures below that required for complete combustion. Improperly adjusted excess air levels are one of the major causes of CO and smoke emissions from small combustion sources.[13,14,15]

Before any fuel can be burned, it must be mixed with combustion air. This is accomplished in oil burning units by atomization of the fuel. Fuel is delivered under pressure to the burner nozzle where it is atomized into fine droplets. In larger units, steam or air may be used to aid in fuel atomization. The combustion air is introduced through swirl vanes located



Percent Excess Air[a]

[a] Values vary for various fossil fuels and combustion unit characteristics

Source: Reference 3

FIGURE 5-3. GENERAL TREND OF SMOKE, GASEOUS EMISSIONS, AND EFFICIENCY VERSUS THE PERCENT EXCESS AIR FOR OIL-FIRED RESIDENTIAL HEATERS in the burner throat. The swirl vanes promote rapid mixing between the air and the atomized fuel. Uneven fuel/air distribution can lead to high CO emissions. This most often occurs because of improper fuel pressure or a worn, damaged, or clogged burner nozzle.

High CO emissions may be encountered when burning coal if the coal is not evenly distributed on the grate. Since coal is a solid, it is more difficult to obtain good fuel/air mixing. Hence, the excess air levels required for coal burning are higher than those used for either oil or natural gas.[11]

Unlike utility and industrial boilers, many residential and commercial heaters are fired in cycles and CO emissions during burner startup and shutdown can be very high. This is because air continues to flow through the combustion chamber due to natural draft during the burner off period. At burner startup, the cold combustion chamber walls cool the combustion gases before complete combustion can occur.[16] Besides cooling the combustion chamber, the heat carried away by the air contributes to a decrease in overall fuel efficiency.[17]

A source of post burn emissions for oil fired equipment is fuel leakage from the nozzle.[14] The nozzle absorbs heat from the hot refractory causing increased CO emissions.[16] In coal fired stokers, the coal bed continues to smolder during the off cycle. Since only a limited amount of air (that supplied by natural draft) is present, high CO and/or smoke emissions usually result.[11]

5.3.3 Control Techniques

The following paragraphs discuss the principles used in reducing CO emissions from residential, commercial, and institutional heaters. It is recommended that the measures discussed be implemented by qualified service personnel who are specially trained and who are experienced with the combustion system. Sources for verifying the expertise of service personnel are 1) the vendor of the combustion system, 2) building safety regulatory agencies, and 3) local fuel vendors.

The most practical technique for reducing CO emissions from residential, commercial, and institutional heaters is proper unit maintenance. Several studies have shown that old, worn out, poorly constructed, or maladjusted burners are responsible for unnecessarily high levels of air pollutant emissions.

Other methods of reducing CO emissions are:

1. Reduce unit fuel consumption by improving steady state and cyclic efficiency,
2. Prevent the cooling off of the combustion chamber in between heating cycles by dampers,
3. Equip new heaters with combustion modification designs such as flame retention burners and flue gas recirculation, and
4. Fuel substitution.

5.3.3.1 Effect of Maintenance

Guidelines for proper maintenance and tuning of residential and commercial heating units are available from many sources including government agencies, equipment manufacturers, and various trade groups.[13,14,15] In summary, these guidelines recommend the following maintenance procedures for oil and gas fired residential and commercial heaters:

1. Clean burner and heat transfer surfaces
2. Clean fuel delivery system
3. Set excess air.

In addition to minimizing CO emissions, a burner tune-up such as described above can improve fuel efficiency. An annual tune-up is recommended by burner manufacturers to maintain good operation.[16]

Improvements in the heating system fuel efficiency can result in lower total emissions of all pollutants as less fuel is consumed to supply a given heating load. A variety of techniques is available which can result in modest improvement in efficiency. Some of these techniques are listed below:

1. Flame retention burners
2. Added insulation
3. Flue gas recirculation
4. Reduced firing rates.

Reduced firing rates have the added benefit of reducing spike (or sharply increased) CO emissions. At reduced firing rates, cycle fired equipment tends to run a greater percentage of the time, thus reducing off-cycle heat losses and reducing the number of cold start-ups. Since the quenching effect of combustion gases touching cold areas in the combustion area upon start-up is a major contributor to spike emissions, any decrease in off-cycle heat losses will have the tendency of reducing these emissions.

5.3.3.2 Fuel Substitution

As indicated in Table 5-5, CO emissions from small coal-fired units are significantly higher than CO emissions from oil or gas units. Therefore, substitution of oil- or gas-fired equipment for small coal-fired equipment could result in substantial reductions in total CO emissions from that equipment.

Although modern coal burning units are designed to reduce routine maintenance and achieve efficiencies approaching that of oil-fired equipment, CO and smoke emissions are still quite high, particularly during the units off-cycle.[11]

5.3.4 Cost of Controls

The most effective technique for reducing CO emissions is proper maintenance of the heating unit.[16] A general tune-up of an oil-fired residential furnace including nozzle cleaning or replacement, changing the filters, and adjustment of the proper excess air level costs in the range of $60 to $80 (1978 dollars).[18] The cost for tuning a gas-fired furnace is somewhat less; no information was available on maintenance costs for coal-fired heaters. Unit efficiency generally increases with tuning and savings in fuel costs can often offset the tuning cost. In addition, increased unit life and trouble free operation act as incentives to keep these units properly tuned. Burner sales and service organizations recommend that these units be tuned once per year, preferably at the start of the heating season. [13,16]

New burners may be required in units for which normal maintenance procedures fail to reduce emissions or improve efficiency. New flame retention burners can be installed in these units for around 250 to 300 dollars in 1978.[18] Since these burners can operate at lower excess air levels than conventional high pressure burners, the resulting improvement in efficiency can result in substantial fuel savings.[18]

5.3.5 Impact of Controls

5.3.5.1 Emissions Reduction

Several studies have shown that old, worn out, or damaged burners are responsible for unnecessarily high CO emission levels. In the residential heating sector, the number of units which would require replacement due to low efficiency, high smoke or CO emissions, or other poor performance characteristics, has been estimated to be in the range of 9 to 30 percent.[16,19]

Tuning or replacing the burners in commercial and institutional heating units can also reduce CO emissions. The actual reduction in emissions resulting from these measures was not determined. However, their effect is probably less significant than for residential heaters because CO emissions from commercial heating units are typically lower than those from residential heaters due to more frequent maintenance and more efficient design.

As mentioned previously, a number of techniques are available which can provide modest increases in fuel efficiency. The application of these techniques can result in substantial fuel savings while simultaneously reducing total CO emissions.

Even though coal accounts for less than 3 percent of the total amount of fuel burned in small combustion sources, CO emissions from coal burning equipment represent over 70 percent of the total estimated CO emissions. Hence, a reduction in the use of coal could provide a significant reduction in total CO emissions from these sources.

5.3.5.2 Environment

The application of controls for CO emissions from small combustion sources will have both positive and negative impacts with respect to other pollutant discharges. Many of the control techniques discussed above result in improvements in the combustion characteristics of the system. As a result, these same techniques often provide a reduction in the emission rates of other combustibles such as smoke and unburned hydrocarbons.

Sulfur dioxide emissions are not directly affected by CO control techniques as most all of the sulfur in the fuel exits with the flue gas. Total sulfur emissions, however, can be reduced by any technique which results in improvements in fuel efficiency.

Increased NO_x emissions may result from the application of CO controls. Those techniques which produce an increase in combustion intensity generally result in higher flame temperatures with increased NO_x production.[3]

A considerable amount of effort has been directed toward developing techniques which reduce NO_x emissions from combustion sources. In general, these techniques depend on reducing the maximum flame temperature, limiting the availability of oxygen at the flame, or a combination of these factors. Unfortunately, these techniques may result in increased CO emissions.[3]

5.3.5.3 Energy Requirements

The energy impacts of applying CO control techniques to small combustion systems occur primarily through effects on fuel efficiency rather than the energy requirements of the control method itself. The most promising CO control techniques (i.e., tuning, replacement of poor units, firing rate reductions, and flame retention burners) can all result in improved efficiency and reduced fuel consumption. These improvements in efficiency result from decreased losses of combustibles such as smokes and CO and a decrease in both on- and off-cycle stack heat losses.

5.4 SOLID WASTE INCINERATORS

Incinerators, combustion systems that burn waste materials, are used to reduce the weight, volume, and volatile contents of refuse. Because refuse characteristics vary widely, methods of incineration must be adjusted to fit specific types of waste material. In general, refuse differs from fossil fuels in that refuse grate-loading rates are much lower, and excess air rates are higher.

Carbon monoxide is a significant pollutant from most incineration processes. The greatest CO emissions are produced by municipal, industrial, and commercial incinerators.[20] Although emission rates from residential incinerators are high, total carbon monoxide emissions are low because of the low volume of waste burned in residential units.[6]

The following sections give process/design descriptions for different types of municipal, industrial, and commercial solid waste incinerators. Process emission sources and factors are included, as are discussion of control techniques, control costs, and the impact of controls on carbon monoxide emission reduction, the environment, and energy requirements.

5.4.1 Municipal Incinerators

Municipal incinerators are designed to dispose of combustible wastes from residential, commercial, and industrial sources which do not maintain their own waste disposal facilities. (Heavy industrial, agricultural, and oversize bulky wastes are not usually treated in municipal incinerators.) Municipal incinerator capacities range from 45 to 900 metric tons/day (50-1000 tons/day).[21] The estimated average composition of municipal incinerator feed is shown in Table 5-7.

TABLE 5-7. ESTIMATED ANNUAL AVERAGE COMPOSITION
OF MUNICIPAL REFUSE

Component	Mean Weight Percent
Glass	9.9
Metal	10.2
Paper	51.6
Plastics	1.4
Leather and rubber	1.9
Textiles	2.7
Wood	3.0
Food wastes	19.3
	100.0

Source: Reference 21

5.4.1.1 Process Description

Municipal waste is usually transported to the incinerator via truck. After being weighed, the waste is dumped into storage bins or charging hoppers. At times the waste is shredded prior to incineration. Refuse is either batch-fed or continuous-fed into the furnace. Process combustion control is improved when continuous firing is employed.

A variety of furnace types are currently used in U.S. municipal incinerators. Nearly all municipal incinerators are multiple-chambered. Most municipal batch-fed incinerators consist of vertical cylindrical or rectangular chambers, into which refuse is charged at regular intervals. The charging doors in vertical batch incinerators are located directly above the grates; in rectangular batch furnaces the doors are in the rear of the roof, and refuse travels from rear to front as it burns.

Underfire air is forced up through the incinerator grates, while overfire air is introduced through furnace wall ports in the primary combustion chamber. The amount of overfire air must be controlled to maintain combustion temperatures of about 980°C-1090°C (1800°F-2000°F) to avoid quenching.[22] Flue gases pass from the primary combustion chamber to the secondary chamber, where oxidation is completed. Gases from the secondary combustion chamber usually flow to a particulate emission control system.

In continuous-fed incinerators, refuse moves from the charging hopper down the feed chute into the primary combustion chamber. Fresh refuse entering the primary chamber is ignited by the burning waste and hot combustion gases. Continuous-fed incinerators are similar to batch-fed incinerators with the exception of their charging mechanism. In both types of incinerators, furnace temperatures range from 650°C to 870°C (1200°F-1600°F).[22] Flue gases usually remain in the secondary chamber at 870°C (1600°F) for approximately two seconds.[22] Flue gases are cooled by one or a combination of three methods: (1) direct injection and vaporization of water; (2) with a heat exchanger (waterwall or convection boiler, air-cooled refractory, or air preheater); (3) direct dilution and mixing with cool atmospheric air. Flue gases exit the stack at temperatures of 315°C-370°C (650°F-700°F).[22]

5.4.1.2 Process Emission Sources and Factors

Carbon monoxide is emitted from municipal incinerator stacks. Emissions of CO result from improper incinerator design or operating conditions, insufficient secondary combustion chamber temperatures, and disruptions in burning conditions (e.g., during start-up and shutdown, or after charging in a batch-fed incinerator).[6,23] No carbon monoxide emission control devices are currently applied to municipal incinerators. Uncontrolled emissions of carbon monoxide from mutliple chamber municipal incinerators have been estimated at 17.5 kilograms per metric ton of refuse charged (35 lb/ton). Emissions vary with refuse composition and furnace operating conditions.

EPA estimates of total CO emissions from multiple chamber municipal incinerators were 155,600 metric tons (171,500 tons) in 1977.[7] Another source gave a much higher estimate of 265,000 metric tons (292,000 tons), calculated from published emission factors and the amount of solid waste processed.[24]

5.4.1.3 Control Techniques

The CO content of incinerator flue gas is reduced through control of the combustion process. Incinerator furnace design and operation must be carefully controlled so that exhaust gas residence time, furnace temperature, and turbulence are sufficient to achieve complete combustion of CO in the exhaust gas.[25] Although afterburners would reduce CO emissions, this type of system is not applied to municipal incinerators. The incinerator furnace should be designed so that exhaust gas residence times in the secondary combustion chamber are sufficient to achieve oxidation of carbon monoxide. If the incinerator is not operated at a high enough temperature [760°C (1400°F)], increased CO emissions will result.[25]

Sufficient combustion air is necessary to achieve optimum incineration conditions. The underfire air system should provide at least 150 percent of stoichiometric air requirements and the overfire air jets should be able to supply approximately 100 percent of stoichiometric air requirements.[25,26] Jets must be positioned so that full penetration of the furnace gases and uniform mixing are achieved. It has been reported that sidewall jets are more effective than roof jets in promoting maximum mixing.[25] Thorough mixing ensures that sufficient oxygen for complete combustion is available in all parts of the furnace. Cold gases from the burnout zone of the furnace must be mixed with hot gases from the burn zone to prevent gas stratification and quenching. Controlled underfire air, forced up through the furnace grate, produces turbulence in the burning refuse bed and thus ensures a more uniform ignition of the waste.[25]

Continuous-fed incinerators are more easily operated within design parameters than batch-fed incinerators because the characteristics of refuse reaching the furnace are more uniform. If too much fresh charge is loaded into a batch-fed incinerator, the gases from the burning refuse already in the furnace may be quenched, thus producing high levels of carbon monoxide. Excessive charge may also increase the rate of burning exceeding air supply capabilities. When this occurs, carbon monoxide emissions increase because residence time in the secondary combustion chamber is insufficient and because there is not enough air for combustion of CO in the exhaust gas.

5.4.1.4 Cost of Controls

No additional equipment, labor, or fuel is used to control carbon monoxide emissions from municipal incinerators. Therefore, no capital or operating costs are incurred.

5.4.1.5 Impact of Controls

Emission Reduction--Carbon monoxide emissions from municipal incinerators are minimal if the incinerators are operated according to design specifications. Although CO emissions would be reduced by more careful control of combustion conditions, it is not known how much CO emissions can be reduced by improving operating practices. It is estimated that afterburners would reduce CO emissions by as much as 90 percent for cases where combustion temperatures would otherwise be less than 760°C (1400°F).

Environment--Operation of municipal incinerators so that carbon monoxide emissions are controlled would not affect the emission rate of nitrogen oxides (NO_x) from the incinerator. Because incinerators operate at relatively low temperatures, most of the nitrogen oxides are formed by direct conversion of chemically-bound nitrogen in the refuse rather than by the high temperature reaction of nitrogen in the combustion air. In general, good operating practice should result in lower emissions of particulates and hydrocarbons as well as carbon monoxide.

Energy Requirements--Municipal refuse has a similar heating value to that of peat or lignite.[27] The heat content of refuse has been estimated to range from 9.2-10.4 megajoules/kilogram refuse (3,935-4,450 Btu/pound). No supplemental fuel is necessary to maintain refuse combustion. The carbon monoxide content of the furnace exhaust gas varies with refuse content and furnace operating conditions; no exhaust gas heat contents were reported. No estimates are available for the energy requirements of afterburner systems used on municipal incinerators.

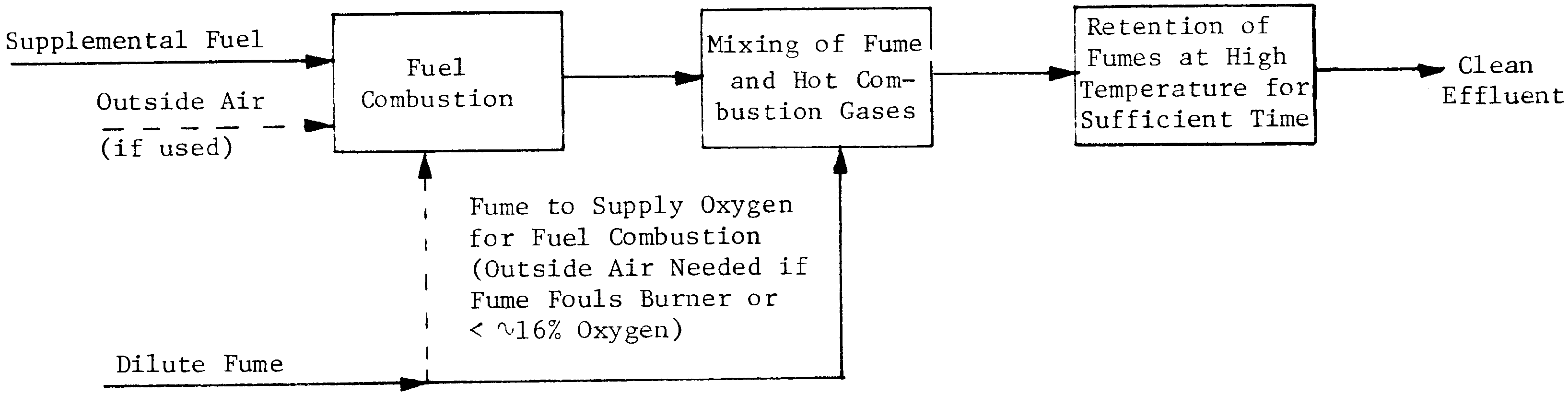
5.4.2 Commercial/Industrial Incinerators

Many commercial and industrial operations (e.g., grocery stores, apartment complexes, textile and woodworking industries) use small incinerators to burn refuse. Most of the units are batch-fed, and many are of single chamber design.[21] The following paragraphs describe several of the more widely used furnaces.

For purposes of this discussion, waste gas streams are divided into two groups--those which require supplemental fuel for incineration and those which do not. Incineration of those streams which can support combustion and therefore do not require supplemental fuel is straightforward. It can be treated as a fuel quality stream and burned in a normal waste gas burner. The resulting temperature, greater than 1200°C (2200°F), is sufficient to completely oxidize any CO.[1] In some cases it may be possible to use the waste gas as fuel in a boiler or process heater and thereby recover its heating value.

The incineration of a waste gas which cannot support combustion and so requires supplemental fuel needs careful design of the incinerator equipment to ensure good CO removal. Temperature, residence time, and the degree of mixing all directly influence the performance of the afterburner. Figure 6-1 diagrams the sequence of steps required for successful incineration of dilute waste gases.

Temperature and residence time requirements for dilute waste gas incineration are discussed together since they are interchangeable to some degree. A higher operating temperature allows use of a shorter residence time combustion chamber and longer residence times allow lower temperatures. This flexibility is limited due to the strong temperature dependence of oxidation rates. Figure 6-2 shows the general effects of temperature and residence time on oxidation rates in a flow-through reactor.[1] These curves do not represent carbon monoxide specifically, but instead give an indication of how combustible pollutants respond to these operating variables. Afterburner experience shows that temperatures of 760-790°C (1400-1450°F) are



Source: Reference 1

FIGURE 6-1. STEPS REQUIRED FOR SUCCESSFUL INCINERATION OF DILUTE FUMES

The combustion chamber and heat recovery equipment are the major pieces of equipment for an incineration system. Auxiliary equipment includes blowers, ducts, supporting structure, and de-entrainment devices. Blowers are needed if the waste gas is at insufficient pressure to move it through the ductwork and the combustion chamber. The blower may be either forced draft or induced draft. Each type of fan has advantages and disadvantages depending on the specific application.

The design and layout of the ductwork depends primarily upon the source of the waste gas and the location of the incinerator. Careful attention should be paid to its design for safety and economic reasons. Long duct runs can cost more than the afterburner itself. Condensation of combustible material can occur even in insulated ducts, causing a fire hazard. For those applications where the waste gas is at a concentration above 25 percent of the lower explosive limit (LEL) of the gas, but below the upper explosive limit (UEL), provision must be made to prevent flashback through the ductwork to the process source.[1] This is done by providing high velocity sections where the waste gas velocity is higher than the flame propagation velocity.[1] Another preventive measure is to dilute the waste gas with air to below 25 percent of the LEL. If concentrations are above the UEL, the waste gas may be ducted without the need for air dilution.[1] It is essential that air be excluded at all points between the waste gas source and the incinerator to prevent an explosive mixture from forming.[1]

The supporting structure for the afterburner represents an important piece of auxiliary equipment insofar as installation is concerned. If the system is mounted on a concrete pad on the ground, its weight will have little influence on installation. However, long duct runs can be avoided if the incinerator can be located close to the waste gas source. This arrangement results in a safer and less expensive system. Roof mounting is therefore frequently done since besides avoiding long duct runs it also saves space within the building and eliminates the need for a tall stack on the incinerator. The primary disadvantage of this location is that for roofs not strong enough to take the additional load, a special (and expensive) supporting structure will be required; or if this cost is prohibitive, lightweight afterburner designs or ground level installation will be needed.[1]

In some applications, the CO-containing waste gas may contain liquid or solid particulate matter which may significantly affect operation of an afterburner. Provisions for removal of this must be made in equipment design and selection to ensure proper operation of the incinerator. There are a large number of different types of equipment for removing particles and mists including fabric filters, electrostatic precipitators, cyclones, demisters, etc. Depending upon the nature of the solid or liquid, suitable devices can be installed upstream of the afterburner.

<u>Operating principles</u> -- Good removal of the carbon monoxide in a waste gas simply requires contacting the gas with sufficient oxygen at high enough temperature for the CO to be oxidized in the time available. Therefore, the three principles of good combustion--time, temperature, and turbulence--hold true for waste gas incineration as well. The difficulty does not come in recognizing their value, but in actually putting them into practice. The following discussion presents information on the conditions necessary for proper operation of a thermal incinerator to control carbon monoxide.

6. INDUSTRIAL PROCESS SOURCE CONTROL SYSTEMS

This section examines those control systems which are used to control carbon monoxide emissions from industrial process sources. The specific controls examined include:

1. incinerators (thermal and catalytic)
2. flares and plume burners, and
3. carbon monoxide boilers.

A technical and economic assessment is presented for each of the controls listed above. The technical assessment includes discussions on equipment and operating principles, control efficiencies, and feasible areas of application. The economic assessment includes both capital and annualized cost curves for representative systems.

6.1. INCINERATORS

Incineration is the most applicable and efficient control technology for reducing carbon monoxide emissions from most industrial process sources. There are two basic designs currently used in the pollution control field for incinerators (or afterburners)--thermal and catalytic. Both have advantages in certain applications and both have been used extensively to destroy combustible pollutants in waste gas streams by oxidation to CO_2 and water. The main use of afterburners in the past has been for odor, hydrocarbon, and smoke control. There are some applications, however, in carbon monoxide control. The remainder of this section examines the application of incinerators specifically for the control of carbon monoxide emissions.

6.1.1 Equipment and Design Parameters for Thermal Incinerators

Equipment--Carbon monoxide emissions are controlled in thermal incinerators by heating in the presence of oxygen the CO-containing waste gas to a temperature sufficient to allow complete oxidation in the residence time available. The incinerator itself is a steel shell, refractory-lined combustion chamber. A burner is located at one end through which the waste gas is introduced into the chamber along with supplemental fuel, should it be needed. Alternatively, the fuel may be burned with air and the hot combustion gases mixed with the waste gas just after the burner. This arrangement is usually used when the waste gas does not contain enough oxygen to oxidize all the fuel, carbon monoxide, and other combustible pollutants present in the waste gas.

As fuel costs have risen in recent years, the incentive for recovering available heat in the incinerator flue gas has become strong. This has led to the application of numerous heat recovery techniques. Recovery methods include heat exchange between hot flue gas and incoming cool waste gas, recycling a portion of the hot flue gas back to the process to supply heat directly, and using the heat to generate steam for other processing or heating loads in the plant. Fuel savings from employing any of these alternatives can usually pay for the cost of the heat recovery equipment.[1]

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5.4.2.1 Process Descriptions

Flue-fed incinerators are single-chamber, rectangular furnaces in which the stack also serves as a charging chute for refuse. Refuse is dried by gas burners located below the grates. Refuse is ignited through a charging door above the grates, and ash is removed through a cleanout door at the bottom of the furnace. Overfire and underfire air jets are usually installed in both doors.

Conical incinerators are used by some lumber, wood product, and textile industries to burn wood or fiber waste. Combustion control is difficult in this type of incinerator because the addition of combustion air is not controlled. A typical conical burner consists of a cone-shaped sheet metal shell with a mesh screen on top. Refuse is charged through a door near the top of the burner and falls to a fuel pile where it is ignited. Air is supplied through small tangential inlets near the base of the burner.

Silo incinerators are vertical steel cylinders which are sometimes lined with refractory brick. They are charged and fired similar to conical burners, but operate at higher temperatures because of the refractory-lined chamber. Both single- and multiple-chamber units are in current use. Combustion air is supplied through louvers located at the base of the incinerator.

Temperatures in the combustion chambers of the above incinerators will vary with the amount of combustion air, charging method, and type of refuse burned. In general, temperatures range from 540°C-980°C (1000°F-1800°F).[28] In the single chamber incinerators described above, turbulence and gas residence time are difficult to control and vary widely.

The controlled ("starved") air incinerator is a relatively recent development. This type of unit is always two-chambered. The concentration of carbon monoxide-rich exhaust gas produced in the burner's primary chamber is reduced when additional air is added in the incinerator's secondary chamber. Controlled air incinerators may be batch- or continuous-fed, and typically operate at temperatures of 1090°C-1200°C (2000°F-2200°F).[28] Secondary chamber residence time is longer than in conventional incinerators (1.25-1.60 seconds).[29] An efficient starved air incinerator is equipped with a primary burner to initiate incineration and with a secondary burner to oxidize the combustibles in the off-gases when temperatures are less than 870°C (1600°F).

5.4.2.2 Process Emission Sources and Factors

Uncontrolled emission factors for various types of commercial/industrial incinerators are given in Table 5-8.

TABLE 5-8. CARBON MONOXIDE EMISSION FACTORS FOR SELECTED COMMERCIAL/INDUSTRIAL INCINERATORS

Incinerator type	Emission rates (uncontrolled) Kilograms/metric ton	Pounds/ton
Industrial/commercial		
Multiple chamber	5	10
Single chamber	10	20
Flue-fed single chamber	10	20
Controlled air	negligible	negligible

Source: References 6, 29

Emissions estimated for 1977 are shown in Table 5-9. As the table indicates, conical incinerators produced almost 50 percent of the carbon monoxide emitted from industrial and commercial incinerators.

TABLE 5-9. ESTIMATED 1977 CARBON MONOXIDE EMISSIONS FROM COMMERCIAL/INDUSTRIAL INCINERATORS

Incinerator type	Total Mas Emissions	
	metric tons	tons
Conical, all fuels	530,700	585,000
Other, all fuels	655,000	722,000
TOTAL	1,185,700	1,307,000

Source: Reference 7

Control techniques (e.g., afterburners and draft controls) are applicable to flue-fed incinerators and other types of single- and multiple-chamber incinerators.

5.4.2.3 Control Techniques

The more simple design characteristics of most commercial/industrial incinerators make carbon monoxide control through good operating practices difficult. In single chamber incinerators, exhaust gas mixing and residence times are insufficient to achieve complete combustion of CO in the exhaust gas. Conical and silo burners have virtually no means of combustion air control, so temperatures and burn rates will vary.

Direct flame afterburners are reportedly applicable to flue-fed incinerators and other types of commercial/industrial incinerators,[6,21] This type of afterburner typically operates at temperatures of 650-980°C (1200-1800°F), with residence times ranging from 0.3-0.6 seconds.[21] Control efficiencies of 90 percent CO removal can reportedly be achieved if an afterburner is operated at temperatures of at least 760°C (1400°F).[28] Catalytic afterburners are not feasible because exhaust gas from burning refuse contains substances which foul the catalyst.

Installation of controlled air incinerators as replacements for less sophisticated units would result in substantial carbon monoxide emission reductions. These units can be used to combust a variety of wastes and are designed for capacities of 180-1360 kilograms/hr (400-3000 pounds/hr).[29] Emissions of CO from controlled air incinerators have been reported as negligible.[29]

5.4.2.4 Cost of Controls

Chapter 6 contains a detailed presentation of the capital and annualized costs for thermal incinerators. To accurately determine the costs for applying this control to refuse incinerators, flow rates and composition of the flue gas are needed. Due to the variations in operation of existing refuse incinerators, flow rates and composition of the flue gases from the units will change significantly not only from one unit to the next but also from time to time for a given incinerator. Data characterizing compositions, flow rates, and their variations were not available. Without this information accurate costs cannot be determined for thermal incineration of the flue gas from this source.

5.4.2.5 Impact of Controls

Emissions Reductions--If afterburners were applied to existing commercial/industrial incinerators, or if existing units were replaced by efficient controlled air incinerators, carbon monoxide emissions from these sources would be substantially reduced. Based on 1977 emissions data, an emissions reduction of 1,207,000 metric tons (1,331,000 tons) could be achieved assuming these controls had removal efficiencies of 90 percent.

Environment--The use of afterburners will increase the amount of nitrogen oxides (NO_x) emissions from commercial and industrial incinerators. Unless afterburner operating temperatures exceed 980°C (1800°F), however, NO_x emissions will remain relatively small (20-30 ppm).[30] Sulfur oxides emissions may increase if fuel oil rather than natural gas is used as supplementary afterburner fuel. The use of better-designed incinerators, such as controlled air incinerators, as well as afterburners, should reduce emissions of combustible particulates and hydrocarbons in addition to carbon monoxide.[29]

Energy Requirements--Supplementary fuel will be required to maintain combustion in afterburners applied to incinerator stacks. The amount of fuel will depend on the type of refuse burned and the operation of the incinerator. Typical afterburner fuel requirements are described in Chapter 6.
If controlled air incinerators are installed, the small quantities of combustion air required results in reduced amounts of fuel necessary to fire the incinerator itself.[29]

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22. Chansky, Steven H, et al. Systems Study of Air Pollution from Municipal Incineration, Vol. 2. Arthur D. Little, Inc., Cambridge, Massachusetts. March 1970.

4. antimony
5. mercury
6. lead
7. zinc
8. tin
9. sulfur
10. halogens.

All except sulfur and halogens form alloys with the metal catalyst and therefore permanently deactivate the catalyst.[1] However, sulfur and halogens, in most cases, combine in a reversible chemical reaction with the metal. Catalyst activity is usually restored when the sulfur or halogen-containing species is removed from the waste stream.[1]

6.1.3 Incinerator Control Efficiency

The control efficiency of carbon monoxide in dilute quantities in a waste stream by thermal incineration depends primarily upon three factors: residence time, temperature, and degree of mixing. Proper design of an incinerator taking these three factors into consideration can result in a thermal incinerator capable of consistent removal of CO at efficiencies exceeding 90 percent. Higher efficiencies (greater than 95 percent) can be designed for at the expense of higher capital and operating costs to achieve longer residence times and higher operating temperatures.

Control of carbon monoxide by catalytic incineration depends primarily upon the operating temperature and bed volume. Properly designed and operated, a catalytic incineration system can consistently achieve CO removal efficiencies of greater than 90 percent. Higher efficiencies (greater than 95 percent) will require greater capital outlays, mainly for increasing catalyst bed volume. Compensation for deactivation of the catalyst will have to be included in the initial design and during operation to ensure good CO removal over a period of time.

6.1.4 Applicability

Thermal incinerators are applicable to virtually all sources of carbon monoxide containing waste gases which are below the lower explosive (combustion limit. (As mentioned earlier, gases which can support combustion would not be disposed of in an incinerator, but rather flared through a waste gas burner or sent to a boiler or process furnace for heat recovery.) Catalytic incinerators would be limited somewhat in their application to dilute waste gases. This is due to the presence of catalyst poisons in some gases.

6.1.5 Energy Requirements

In general, the energy requirements for thermal or catalytic incinerators depend upon the following factors:

1. concentration of CO and other combustibles in the waste gas,
2. waste gas temperature,
3. oxygen content of waste gas,
4. incinerator operating temperature, and
5. amount of heat recovery employed.

The concentration of carbon monoxide and other combustibles in the waste gas can have a significant effect upon energy requirements for thermal or catalytic incinerators. The heat released upon oxidation of CO at a concentration of 25 percent of the lower explosive limit in a waste gas is sufficient to raise the temperature of a normal cubic meter (0.3 scf) of that gas by 340°C (650°F).

The temperature of the waste gas also affects the amount of energy required for its incineration. Most if not all of the supplemental fuel consumed for thermal and catalytic incinerators is used to raise the temperature of the waste gas up to the design operating temperature of the unit.

If the oxygen content of the waste gas is sufficient (16 percent or greater) to oxidize the supplemental fuel and combustibles in the waste gas, significant energy savings will result. This is because the use of outside air for the oxygen will require fuel to be consumed to heat the air up to the operating temperature of the incinerator.

As mentioned, the heat required to raise the waste gas (and air if needed) to the operating temperature of the incinerator is the primary energy requirement for incineration. Therefore the incinerator operating temperature as well as the waste gas temperature affect the amount of supplemental fuel needed.

Heat recovery techniques can lower the amount of supplemental fuel required for incineration significantly. The simplest and probably most common form of heat recovery employed in incinerators is the use of the hot flue gas from the incinerator to heat up the incoming waste gas. This is referred to as primary heat exchange and a simple diagram of an incineration system utilizing this technique is shown in Figure 6-1. Another heat recovery technique, commonly referred to as secondary heat recovery, utilizes the remaining heat in the incinerator flue gas after primary heat recovery. Application of this technique is limited to plants which have a use for additional heat. Secondary recovery involves further heat exchange with a process stream or use of the hot gases for drying.

To accurately estimate the energy requirements for thermal and catalytic incinerators, each of the above factors must be considered. Due to the potential for wide variation in each, reporting a single energy requirement or set of requirements would not provide an accurate representation. Plots are presented which should yield reasonable estimates of the energy requirements for incineration. Figures 6-6, 6-7, and 6-8 can be used to determine the energy requirements for a wide variety of thermal incinerator applications. Figures 6-9, 6-10, and 6-11 can be used similarly for catalytic incineration. These plots were taken from the Shell Afterburner Systems Study and modified to reflect conditions representative of incinerators designed to control waste gases containing carbon monoxide.[1]

Within the graphs, provisions are made to account for factors affecting the energy requirements for thermal and catalytic incinerators. The operating temperatures of both types of incinerators are fixed and all calculations are based on these temperatures. For thermal incinerators, the temperature chosen was 870°C (1600°F) and for catalytic, 480°C (900°F). These temperatures should be sufficient to oxidize not only all CO in a waste gas but virtually all organics as well.

To calculate the energy requirements for a particular application, it is first necessary to assume a heat exchanger recovery factor. Typical

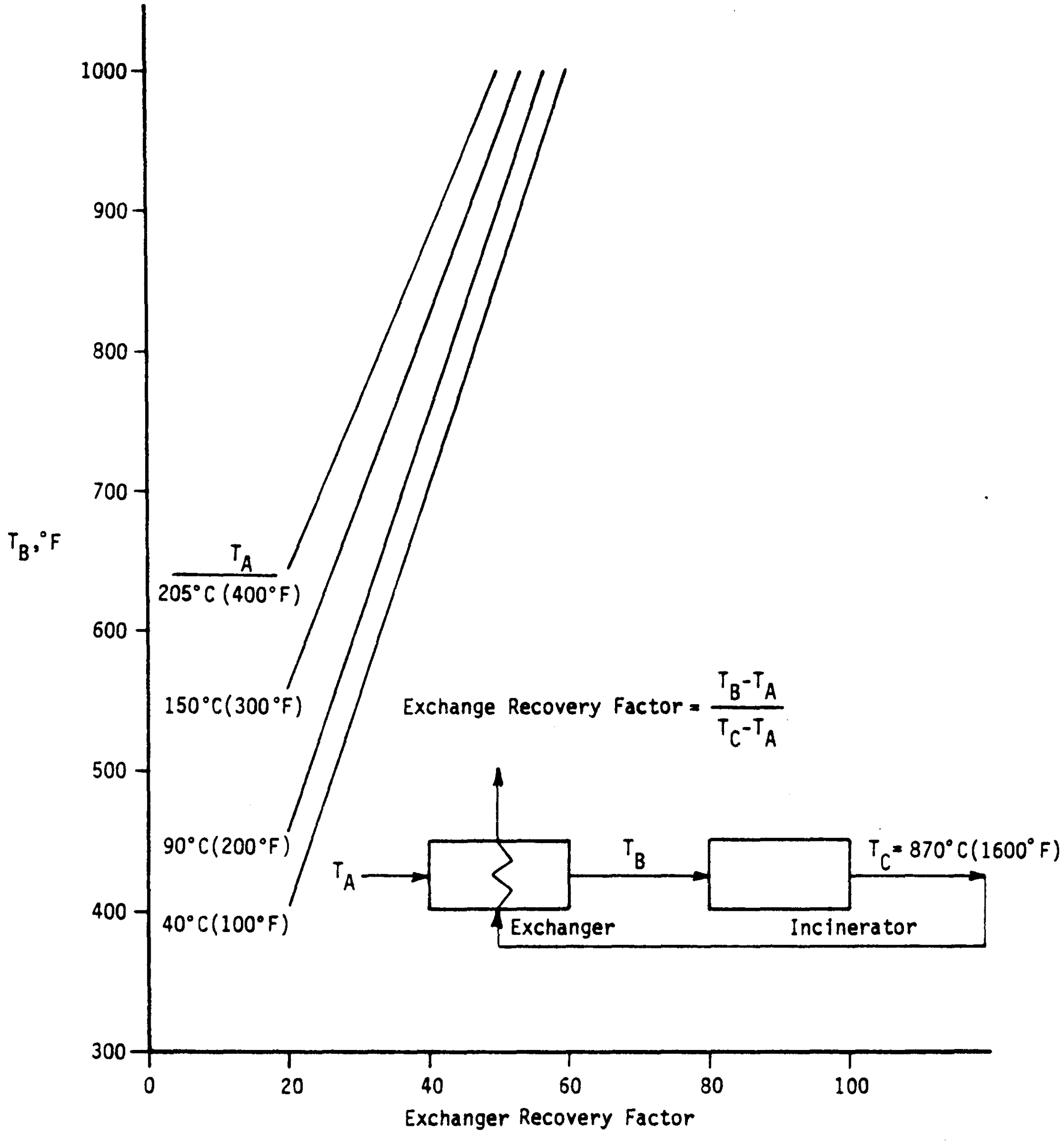

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FIGURE 6-6. EFFECT OF EXCHANGER RECOVERY FACTOR AND WASTE GAS TEMPERATURE ON INLET TEMPERATURE TO THERMAL INCINERATOR

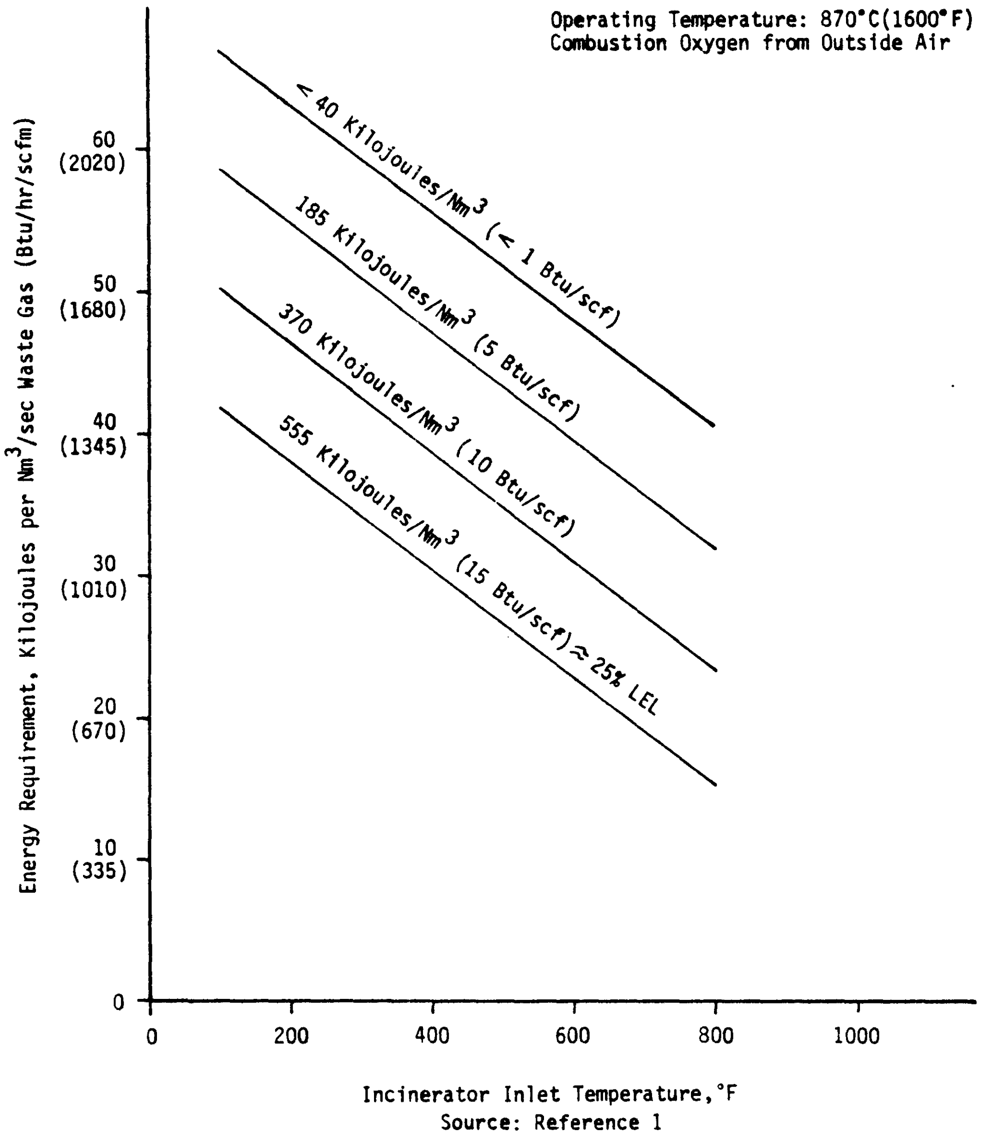

FIGURE 6-7. THERMAL INCINERATOR ENERGY REQUIREMENTS WITH NO HEAT RECOVERY OXYGEN FROM OUTSIDE AIR

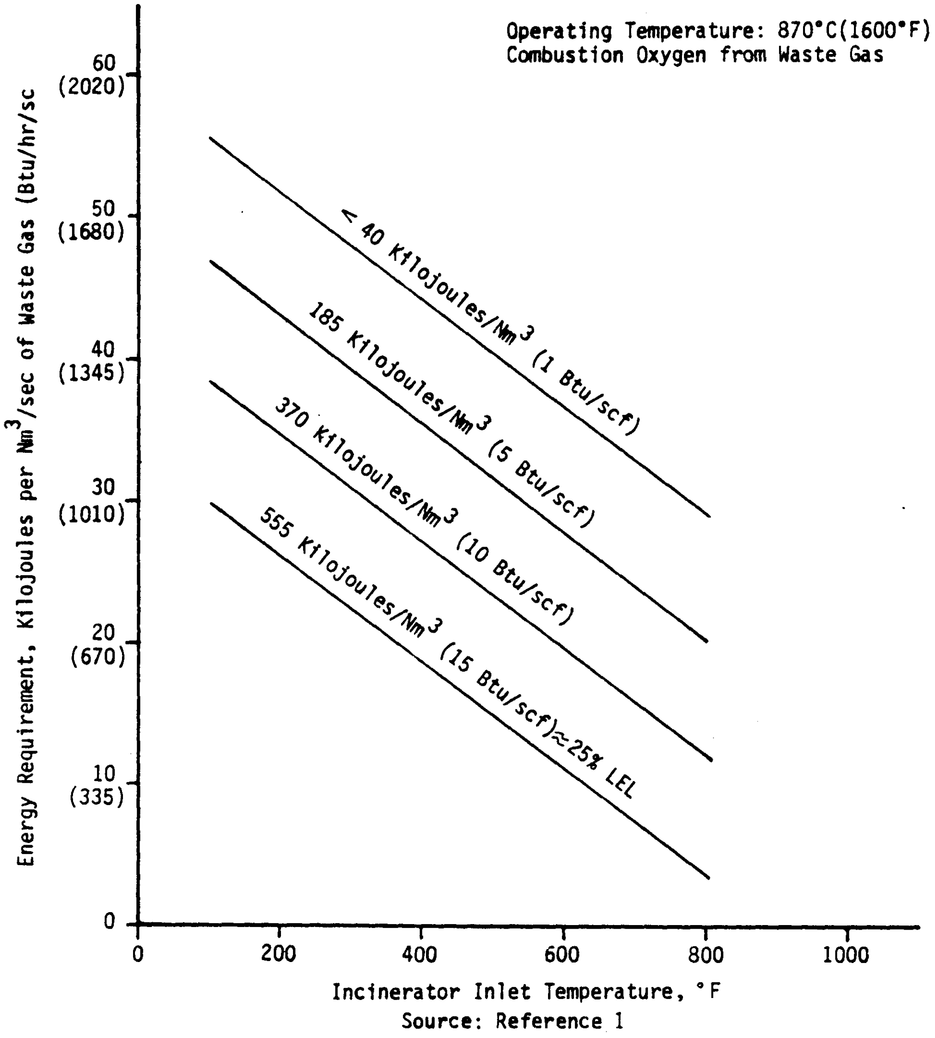

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FIGURE 6-8. THERMAL INCINERATOR ENERGY REQUIREMENTS WITH NO HEAT RECOVERY OXYGEN FROM WASTE GAS

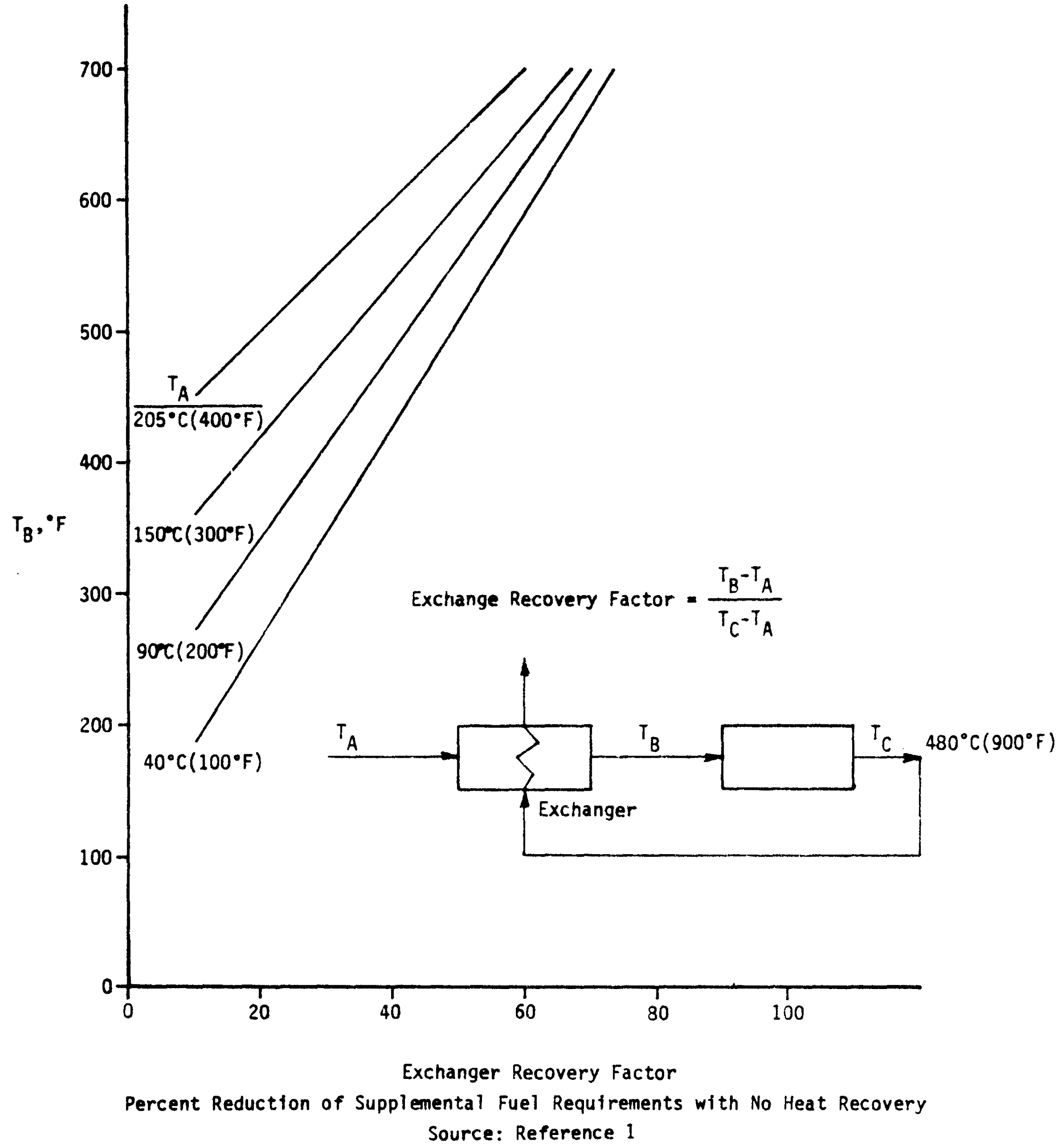

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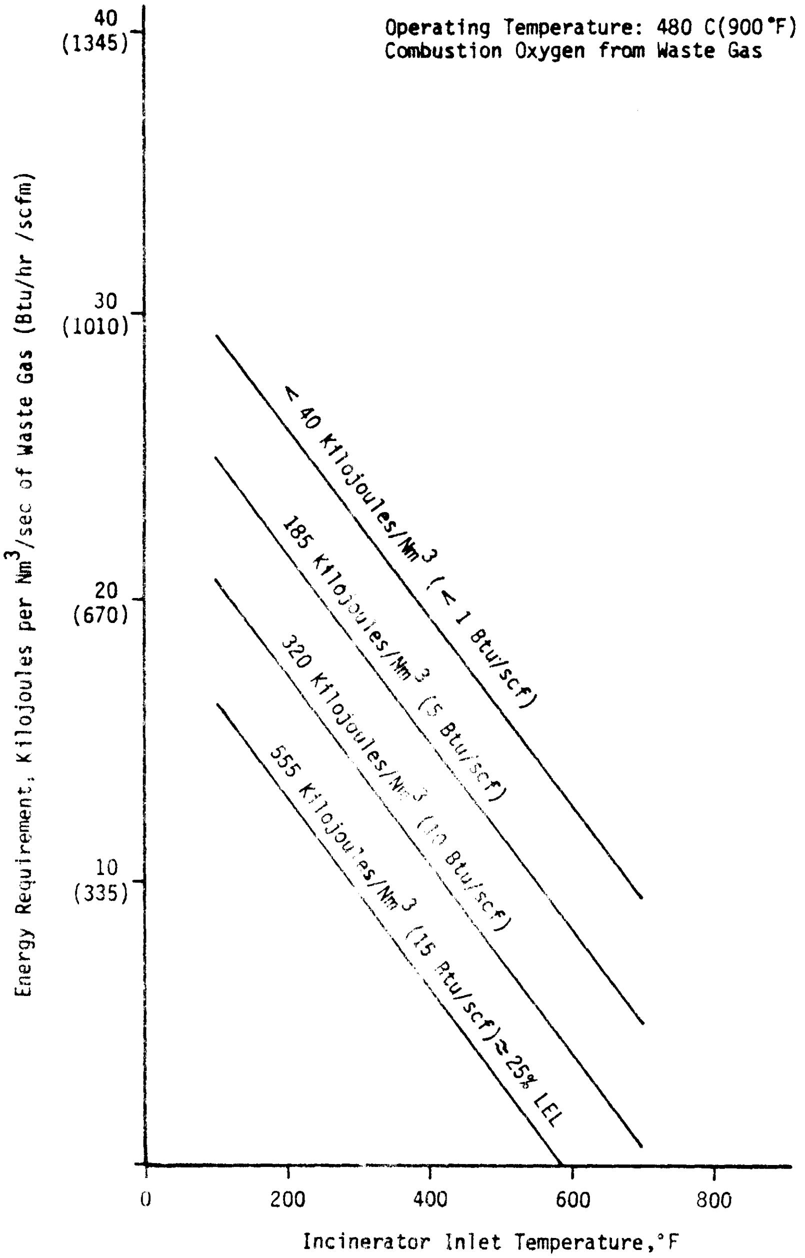
FIGURE 6-9. EFFECT OF EXCHANGER RECOVERY FACTOR AND WASTE GAS TEMPERATURE ON INLET TEMPERATURE TO CATALYTIC INCINERATOR



Source: Reference 1

FIGURE 6-10. CATALYTIC INCINERATOR ENERGY REQUIREMENTS WITH NO HEAT RECOVERY OXYGEN FROM WASTE GAS

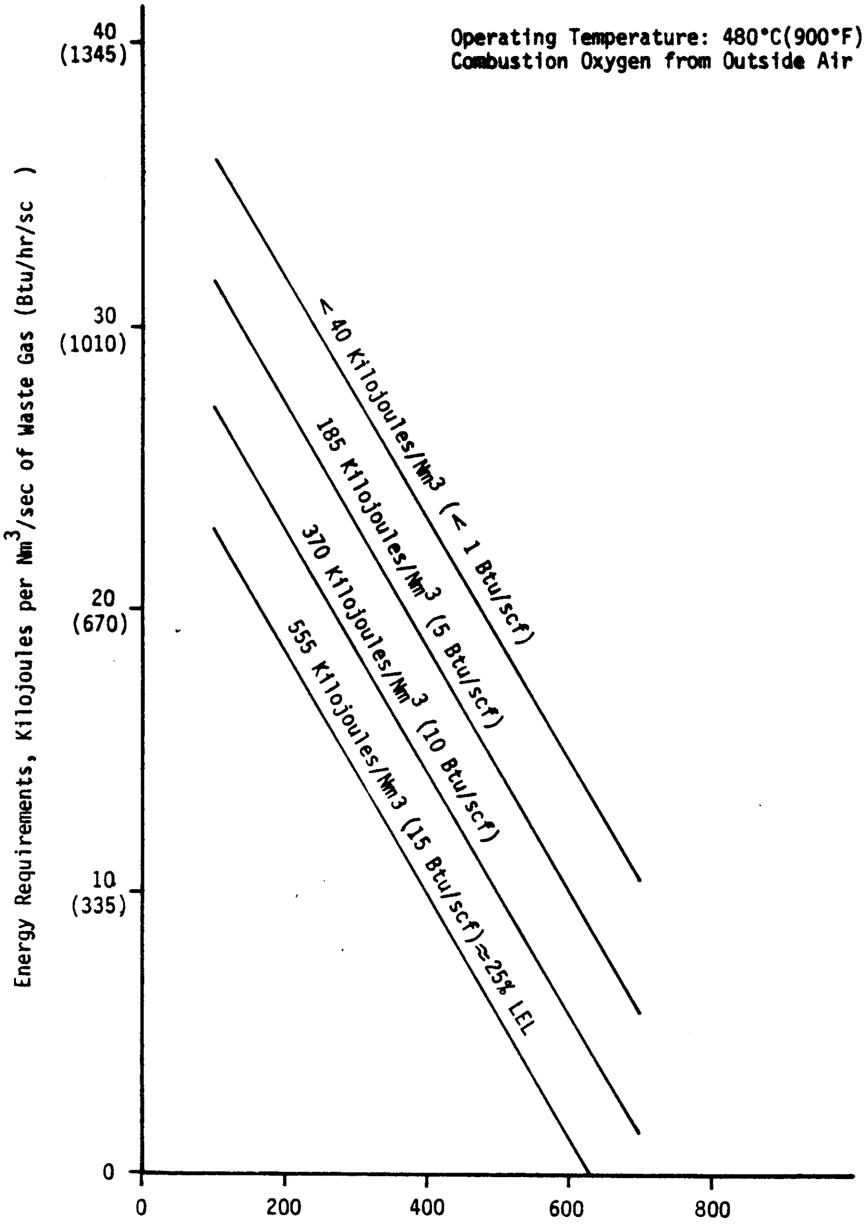


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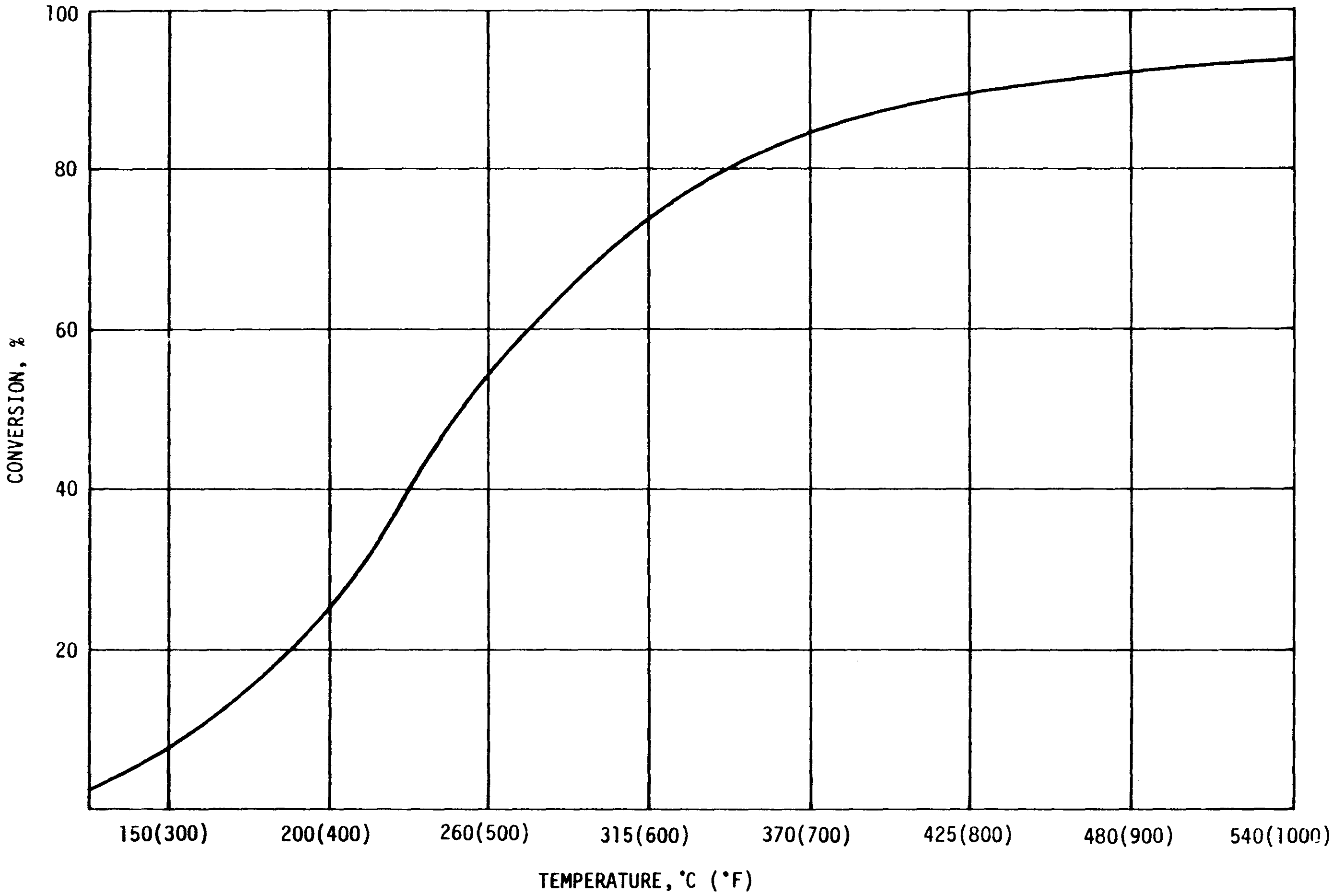
FIGURE 6-11. CATALYTIC INCINERATOR ENERGY REQUIREMENTS WITH NO HEAT RECOVERY OXYGEN FROM OUTSIDE AIR



Source: Reference 1

FIGURE 6-5. EFFECT OF TEMPERATURE ON CATALYTIC CO CONVERSION

Deactivation may occur due to several mechanisms. Thermal aging is probably the most common. It involves micro-structure changes in the active metal or the porous support and loss of active metal by erosion, attrition, and vaporization. Proper operating temperatures can slow this aging and allow satisfactory performance from a unit for three to five years.[1] However, thermal aging may be accelerated by increasing bed temperature. Upper limits of 590°C (1100°F) for alumina-based catalysts and 810°C (1500°F) for all-metal catalysts are recommended by manufacturers for maximum bed life.[1] To keep bed temperatures below these levels, it is generally recommended that catalytic incinerators be limited to waste gases with combustible concentrations below 25 percent of the lower explosive limit.[2]

A second mechanism for deactivation is the buildup of coatings on the surface of the catalyst. These are commonly condensed (and polymerized or partially charred) organic material and/or layers of inorganic particulates. They deactivate the catalyst by inhibiting contact between the gas phase and the catalyst surface. Unlike thermal aging, which is irreversible, periodic cleaning is usually effective in restoring up to 90 percent of the initial catalyst activity where surface coating is the deactivstion mechanism.[1]

The final mechanism for deactivation is poisoning by specific contaminants in the waste stream. These contaminants either combine chemically with the active metal or form alloys with it.[1] These poisons include:

1. phosphorus
2. bismuth
3. arsenic

per unit flow rate of waste gas.[1] Temperature is important because of its influence on the effective rate constant for the oxidation of carbon monoxide. The catalyst bed volume is important in that it determines the operating capability of the system and the overall CO removal efficiency. Figure 6-4 shows the relative effect of catalyst bed volumes on pollutant conversion.[1] It shows that about twice the volume of catalyst is required for 90 percent conversion as for 66 percent conversion. And twice again is required to go from 90 percent to 99 percent. This figure is not based on carbon monoxide specifically, but the general relationship should be representative of that expected for carbon monoxide. Figure 6-5 shows the effect of catalyst bed temperature on the conversion efficiency of carbon monoxide.[1] Control efficiencies greater than 90 percent can be achieved at temperatures above 430°C (800°F).[1]

Besides temperature and bed volume another factor affecting the CO oxidation performance of a catalytic incinerator is the deactivation of the catalyst with age and exposure. This must be compensated for in the initial design and also during subsequent operation of the system.[1] This compensation may include:

1. initial overdesign in catalyst bed volume,
2. raising preheat temperatures as catalyst activity decreases,
3. cleaning the catalyst during periodic shutdowns,
4. replacement of the catalyst, or
5. treating the waste gas for removal of potential poisons prior to feeding into the incinerator.

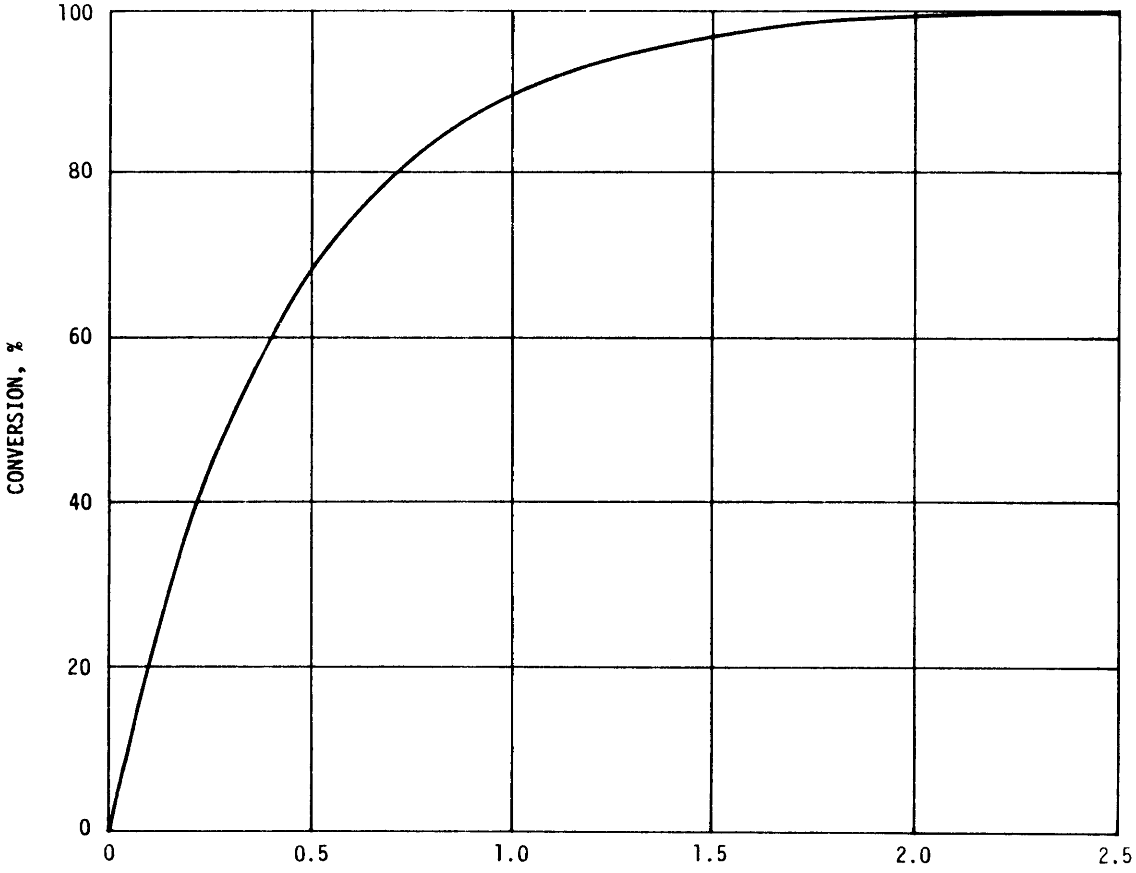


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FIGURE 6-4. VOLUME OF CATALYST/VOLUMETRIC FLOW RATE OF WASTE STREAM*

*Does not apply quantitatively to carbon monoxide.

6.1.2 Equipment and Design Parameters for Catalytic Incineration

Equipment -- The basic equipment used for a catalytic incineration system is shown in Figure 6-3. This consists of a combustion/mixing chamber upstream of the catalyst bed. A preheat burner is usually located in this chamber to bring the temperature of the waste stream up to required oxidation temperature. The chamber is also designed to achieve a uniformly distributed mixture of the combustion gases from the preheat burner and the waste gas. The catalyst bed is located at the end of the chamber. It usually consists of a metal mesh-mat, ceramic honeycomb, or other ceramic matrix structure with a surface deposit or coating of finely divided particles of platinum or other platinum family metals. The metal acts as the catalyst while the matrix structure serves to support the catalyst. The support is designed for high surface area for relatively small bed volumes to maximize the number of active sites where the catalyzed oxidation reaction can take place. Relatively small catalyst bed volumes, 0.014 - 0.057 m^3 (0.5 - 2.0 ft^3), are required per 27 Nm^3/min (1000 scfm) of waste gas.[1] This small volume and the low density of the catalyst bed contribute to relatively small sizes and light weights for catalytic versus thermal units. Heat recovery from the flue gas out of the catalyst bed may be included in the overall system design. It will be similar to that for a thermal unit; however, because of the lower operating temperatures and supplemental fuel requirements, less energy can be recovered.[r]

Design Parameters -- Catalytic incineration of carbon monoxide depends primarily upon two factors, operating temperature and catalyst bed volume

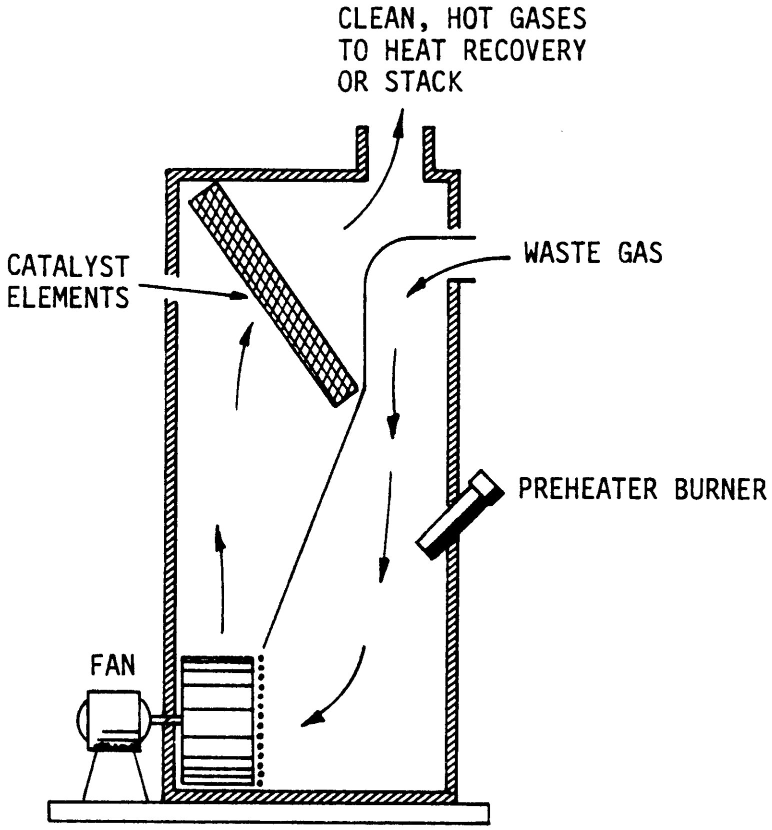
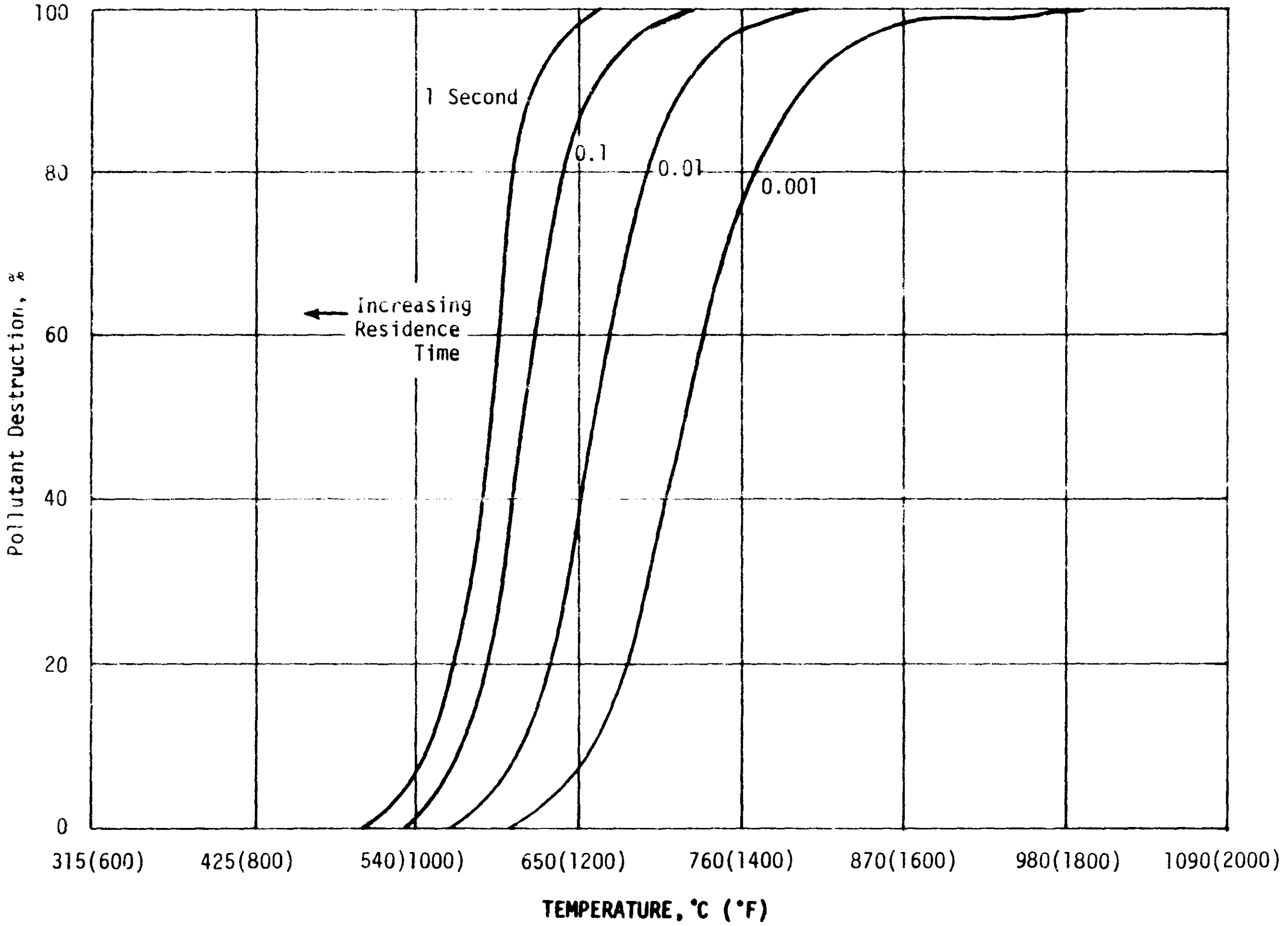


FIGURE 6-3. SCHEMATIC DIAGRAM OF CATALYTIC AFTERBURNER USING TORCH-TYPE PREHEAT BURNER WITH FLOW OF PREHEATED WASTE STREAM THROUGH FAN TO PROMOTE MIXING



Source: Reference 1

FIGURE 6-2. COUPLED EFFECTS OF TEMPERATURE AND TIME ON RATE OF POLLUTANT OXIDATION*

*Does not apply quantitatively to carbon monoxide.

required with an actual residence time at this temperature of 0.2-0.4 seconds after mixing of the waste gas and the hot combustion gases.[1] These conditions should result in nearly complete oxidation of CO.[1] However, due to difficulties in achieving complete mixing of the gases in the combustion chamber temperatures of 870-980°C (1600-1800°F) and residence times of 0.5 seconds are often designed for in actual applications to ensure good CO removal.[1]

As just noted, incinerators with designs which achieve good mixing are needed not only to ensure adequate CO removal but also to allow operation of the system as close to the ideal (and least expensive) conditions of 760°C (1400°F) and 0.2-0.4 second residence times. Operation at this lower temperature and time requires the fuel to be burned as rapidly as possible and the hot gases to be thoroughly mixed with the waste gas.

Thorough mixing can be achieved by using either distributed burners or discrete burners with internal baffles. Distributed burners are placed directly in the waste gas stream and divide the flame into many individual jets surrounded by waste gas. This subdivision greatly enhances the mixing of the waste and hot combustion gases. Distributed burners have certain limitations which make them unavailable for some applications. They are subject to fouling, have somewhat limited turndown, can burn only gaseous supplemental fuels, and are difficult to use when outside air is used to supply oxygen for combustion.[1] Where distributed burners are not feasible, discrete burners are employed. Because of their design (one burner versus several for the distributed design) mixing is more difficult to achieve. Internal baffles and/or longer residence times are needed for sufficient mixing of the gases in the combustion chamber.[1]

heat exchanger recovery factors for primary heat exchange are 35 to 45 percent. Higher recovery factors (up to 85 percent) are possible with secondary heat exchange if potential exists for utilizing this technique at a given site. Knowing the waste gas temperature (T_A) the temperature into the incinerator (T_B) may be determined from Figure 6-6 for thermal incineration or Figure 6-9 for catalytic incineration. Then, entering the appropriate graph, Figure 6-7 or 6-8 for thermal, or Figure 6-10 or 6-11 for catalytic at temperature T_B, and knowing the heat content of the waste gas, the supplemental fuel requirement can be read. Allowing for heat losses from the incinerator may add approximately 5 percent to the fuel requirement shown on the graph.[1]

6.1.6 Environmental Impact

Incineration of waste gases can increase emissions of SO_2 and NO_x. The primary source of the SO_2 is the sulfur contained in the supplemental fuel used in the incinerator. Depending upon specific conditions and sulfur content of the fuel and waste gas, SO_2 emissions may vary from negligible to over 50 ppm. This is not considered significant, however.

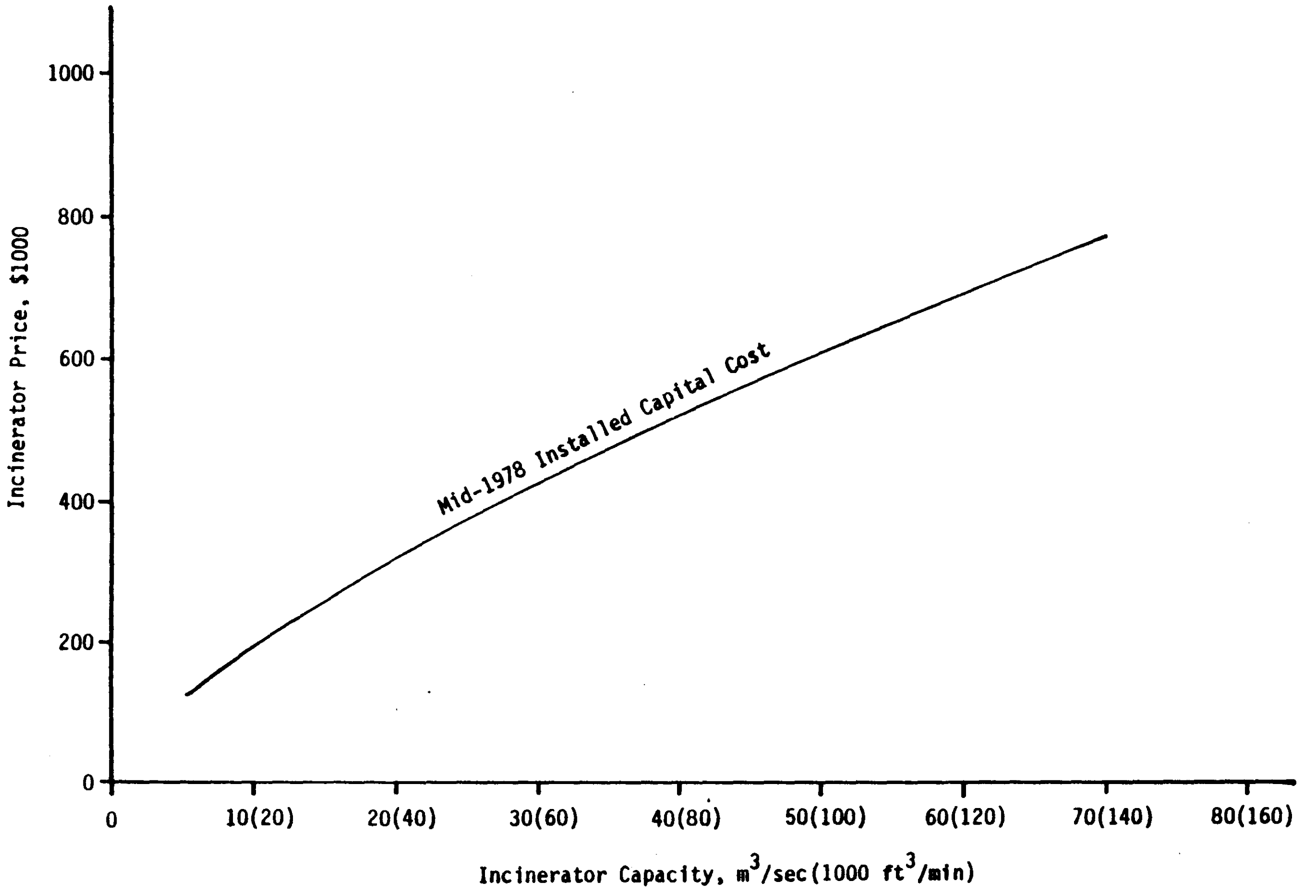
The NO_x emissions result from the oxidation of any nitrogen compounds in the waste gas as well as to a limited extent the reaction between atmospheric nitrogen and oxygen. However, due to design and operation difference, incinerators (particularly catalytic ones) have relatively low NO_x emissions. Reported levels of NO_x in the flue gas from thermal afterburners fired with gas at temperatures up to 980°C (1800°F) are 40-50 ppm and for catalytic afterburners, 15 ppm.[1,2] NO_x emissions from oil-fueled thermal afterburners fired at the same temperatures were reported to be from two to three times higher.[1]

Incineration of waste gases containing halogen compounds can result in the formation of corresponding acids, e.g. chlorine will form hydrochloric acid. Provisions must be made to remove this from the incinerator flue gas. Usually this is done by wet scrubbing.[1]

6.1.7 Costs (Mid-1978 Dollars)

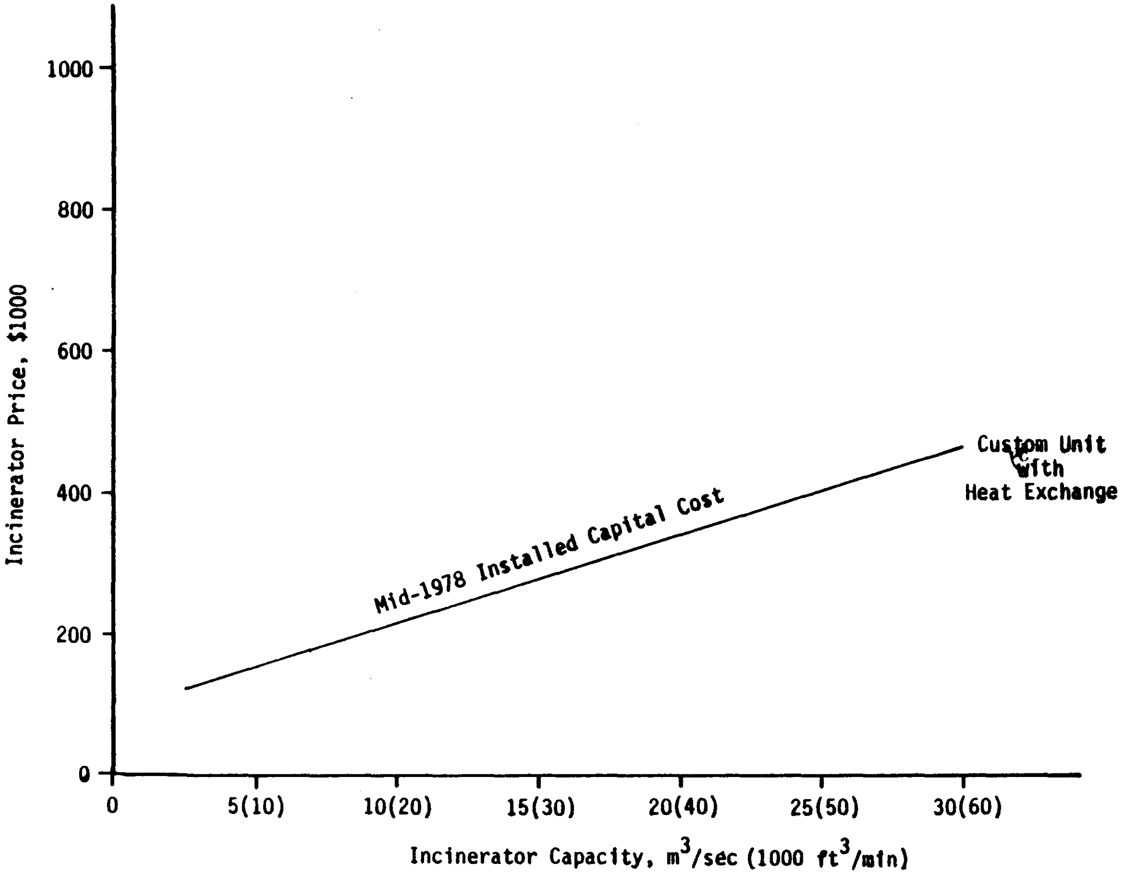
The capital and annualized costs for thermal and catalytic incinerators are presented in this section. Capital costs for incinerators depend primarily upon the flow rate of the waste gas being incinerated, but also are affected by the presence of corrosive compounds in the waste gas which necessitate expensive construction materials. Capital costs will vary to a lesser extent depending upon whether the unit is a package or custom design. Additional capital expenditures will also be incurred if the system is designed for secondary heat recovery. Figures 6-12 and 6-13 present installed capital cost estimates for thermal and catalytic incineration systems.[3] These include costs for the basic equipment as well as all auxiliary equipment such as ducts, blowers, instrumentation, demister, piping, etc., and installation charges.[3]

Annualized costs are presented for thermal and catalytic incinerators in Figures 6-14 and 6-15. These costs include operating and maintenance costs as well as capital-related charged. Table 6-1 shows an example calculation for determining the annualized costs for a thermal incinerator. Basis for the calculation is given in the table. The installed capital cost for the unit was taken from Figure 6-12. Bases for the annualized costs are given in Table 6-2.[1,3,4]



Source: Reference 3

FIGURE 6-12. INSTALLED CAPITAL COSTS FOR THERMAL INCINERATORS



Source: Reference 3

FIGURE 6-13. INSTALLED CAPITAL COSTS FOR CATALYTIC INCINERATORS

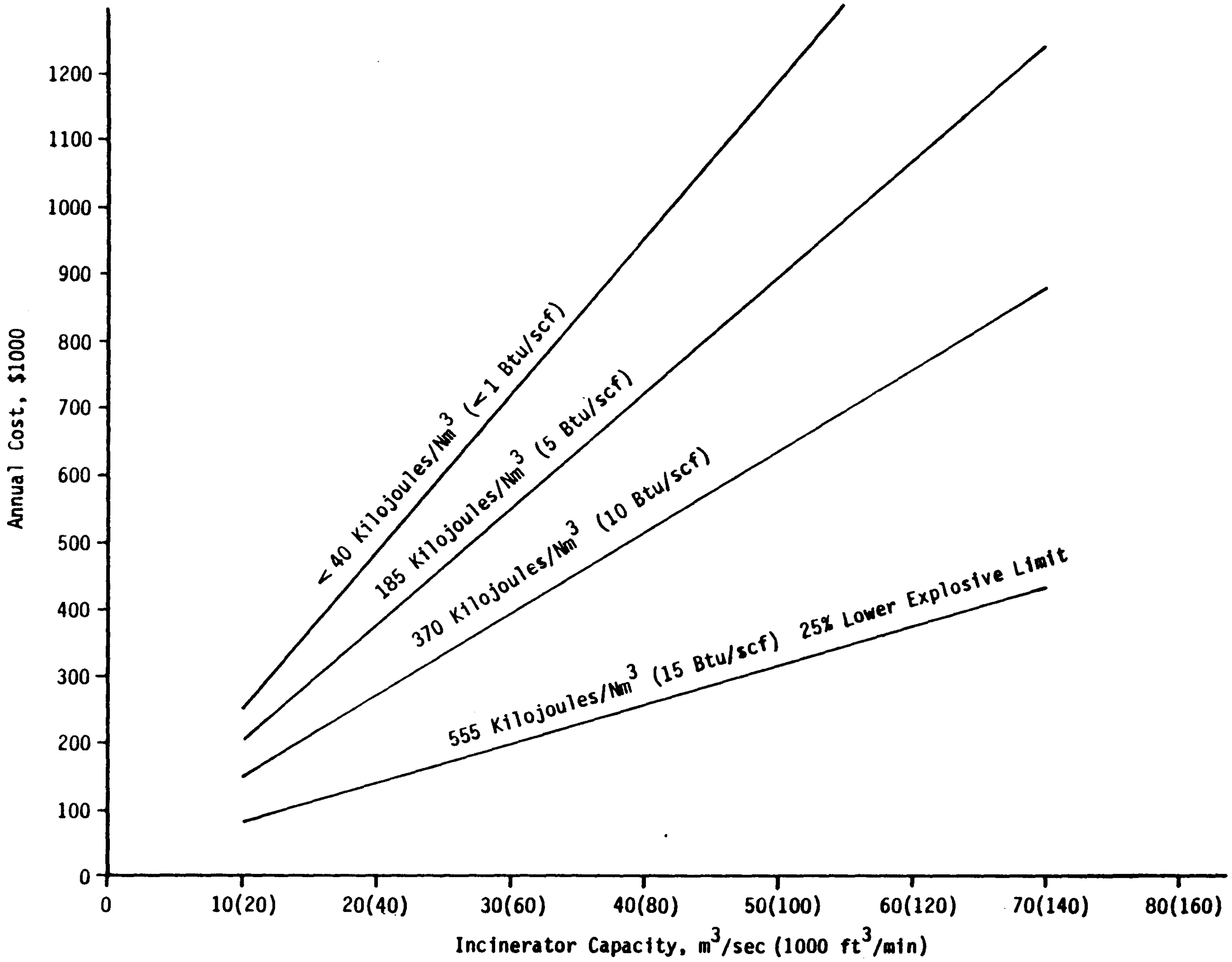


FIGURE 6-14 ANNUALIZED COSTS FOR THERMAL INCINERATORS
(mid-1978 dollars)

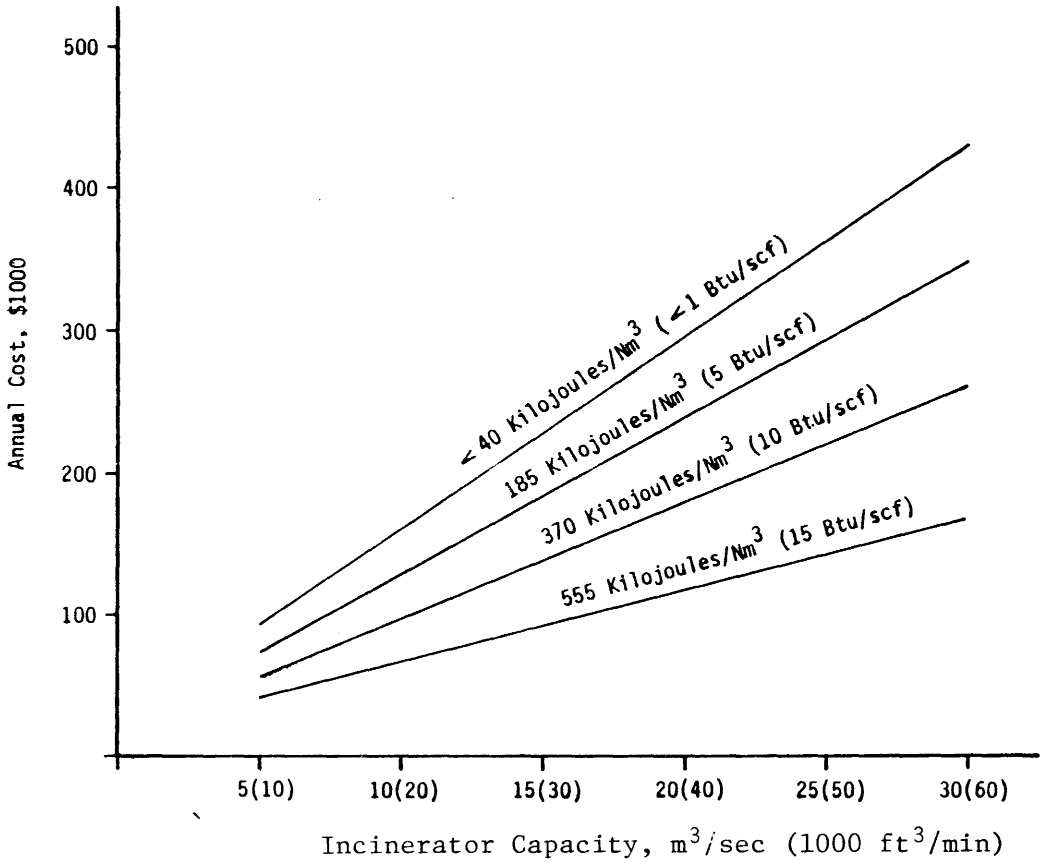


FIGURE 6-15. ANNUALIZED COSTS FOR CATALYTIC INCINERATORS (mid-1978 dollars)

TABLE 6-1

SAMPLE ANNUALIZED COST CALCULATIONS FOR THERMAL INCINERATION (Mid-1978 Dollars)

Design Bases:

Incinerator

Operating temperature = 870°C (1600°F)
Exchanger recovery factor = 0.35
Operating time = 4,000 hrs/yr

Waste Gas

Flow rate = 20 Nm^3/sec (40,000 scfm)
Heating value = 555 kilojoules/Nm^3 (15 Btu/scf)
Temperature = 150°C (300°F)

COMPONENT	COST
Operating and Maintenance	
Fuel	$ 68,000
Electricity	Neg
Labor	Neg
Maintenance	6,200
Administrative overhead	3,400
Fixed Costs	
Capital recovery	50,500
Taxes, insurance, etc.	12,400
Annualized Cost	$140,000

TABLE 6-2

ANNUALIZED COST BASES

OPERATING AND MAINTENANCE COSTS	
Fuel	$2.40/gigajoule (2.50/MM Btu)
Electricity	$0.03/kWh
Operating Labor	
Direct	$10/man-hour
Supervision	15% of direct
Maintenance	2% of installed cost
Overhead	
Plant	50% of labor and maintenance
Payroll	20% of labor

FIXED COSTS	
Capital Recovery (10 yr life, 10% interest)	16.28% of installed cost
Taxes, Insurance, etc.	4% of installed cost

Source: References 1, 3, and 4

6.2 CARBON MONOXIDE BOILERS

The control of carbon monoxide emissions by oxidation in the furnace of a boiler represents an effective and in some cases economical control technique. This method is generally applied only when the CO-containing waste gas possesses a relatively high heating value. The following sections present information on the equipment and design parameters, CO control efficiency, applicability, energy requirements, environmental impact, and economics of CO boilers.

6.2.1 Equipment and Design Parameters for Carbon Monoxide Boilers

A CO boiler is essentially a typical gas-fired steam generating boiler. A few modifications are necessary, however, due to the potential for large variations in the concentrations of combustibles and oxygen in the CO-containing waste gas. Provisions must be made so that the amount of excess oxygen leaving the unit can be determined directly.[5] This may be done intermittently by an Orsat or continuously by an oxygen recorder.

It is also necessary to provide for independent operation of the CO boiler so that its operation will not interfere with that of the process or unit which produces the CO. Water-seal tanks are installed to act as shutoff valves. They permit the CO gases to be sent to the boiler or be passed directly to the stack if the boiler is down.[5]

Supplemental fuel is required to ensure stable operation of the boiler as well as to provide high enough temperatures in the firebox to assure complete burning of the combustibles in the CO-gas stream. The following design criteria have been established for proper operation of CO boilers:[5]

1. supplementary firing should be capable of raising the temperature of the CO-gas stream to over 790°C (1450°F), which is the minimum temperature needed for CO ignition.

2. the furnace temperature should be about 980°C (1800°F) for stable operation.

3. at least two percent excess oxygen in the flue gas should be supplied.

Sizes of the CO boilers may vary from those producing less than 23,000 kg/hr (50,000 lb/hr) of steam to those producing greater than 230,000 kg/hr (500,000 lb/hr).[5] The smaller units will typically be standard pre-engineered boilers; the larger ones will be fully field-erected customized units.

6.2.2 Control Efficiency

The carbon monoxide emissions from a properly operated CO boiler should be below 200 ppm in the flue gas. Numerous applications of CO boilers in the refining industry have consistently achieved this level.[5] Since the concentrations of the carbon monoxide in the gases to the CO boiler are in the range of 5 to 10 volume percent, control efficiencies of greater than 99 percent are achievable by this method.

6.2.3 Applicability

The application of CO boilers to controlling carbon monoxide emissions from industrial sources is limited. These limitations are due to the following reasons:

1. the fuel value of the waste gas should be sufficient so that large quantities of supplemental fuel are not required. A plant or process

will be limited in the amount of steam it can use. Fuel consumption in excess of this for the purpose of incinerating low-heat waste gases is expensive. Incinerators will be able to provide adequate control of these gases at substantially lower costs.

2. the waste gas should be free of species that will foul, attack, or deposit upon boiler internals. Sodium salts, unsaturated aromatics, potassium, vanadium, halogenated compounds, and phosphorous all can result in expensive construction materials, high maintenance, and formation of plumes.

3. the waste gas source must be able to operate independent of the CO boiler.

However, there are several industrial processes which have had CO boilers applied to controlling their waste gases. These include petroleum refining fluid catalytic cracker regenerators, fluid cokers, and carbon black plants. These applications are discussed in Chapter 7.

6.2.4 Energy Requirements

Control of CO emissions by CO boilers will result in an energy savings or credit rather than a penalty. The magnitude of the credit will depend directly upon the temperature and combustibles content of the waste gas. Assuming a boiler efficiency of approximately 75 percent, then 75 percent of the heat content of the waste gas can be recovered in the steam produced.

6.2.5 Environmental Impact

The operation of a CO boiler will result in about the same environmental impacts as a regular boiler. Increased SO_2 emissions will originate from the sulfur contained in the supplemental fuel and increased NO_x emissions will result from any nitrogen compounds in the waste gas as well as thermal fixation of nitrogen contained in the combustion air to the boiler.

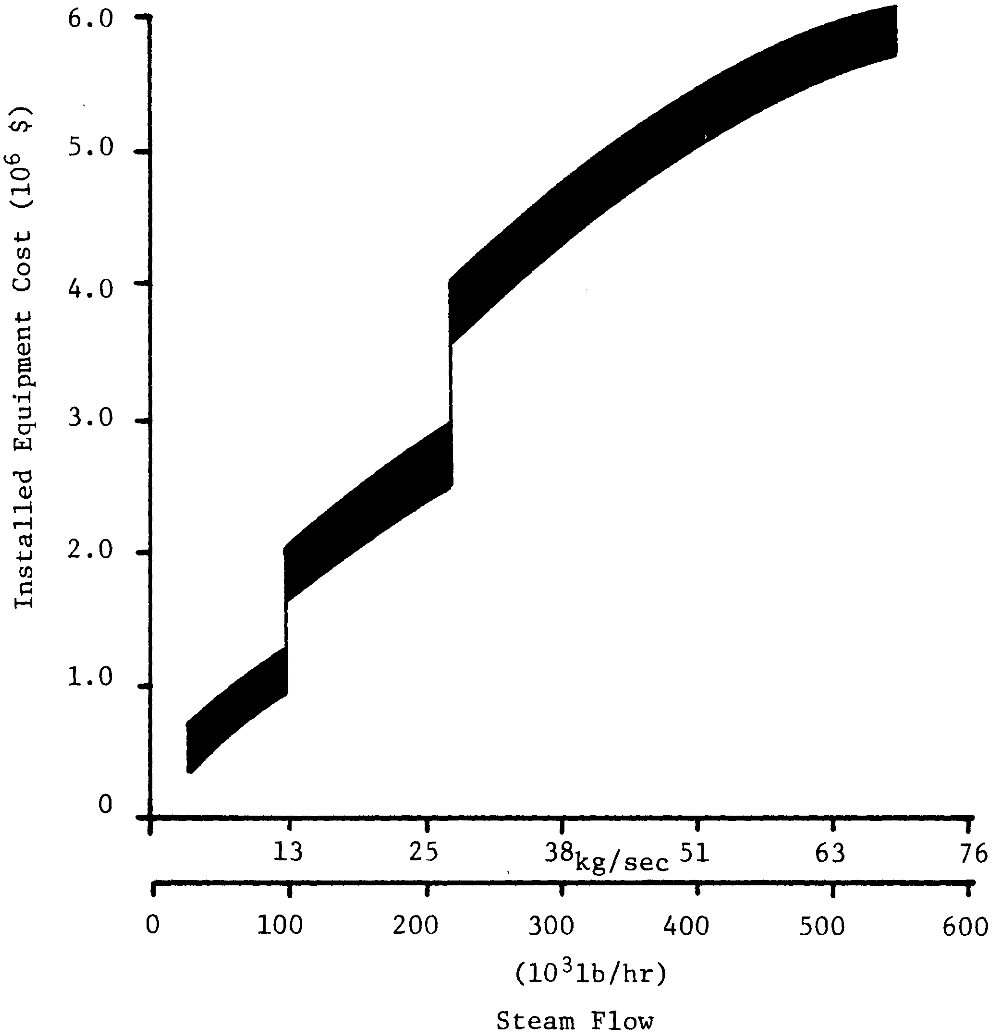
6.2.6 Costs (Mid-1978 Dollars)

The installed equipment and annualized costs for carbon monoxide boilers are presented in Figures 6-16 and 6-17, respectively. The installed equipment costs are based on information provided by a manufacturer of CO boilers.[5] The cost curves reflect data for three separate types of units. For steam flows up to 12.6 kg/sec (100,000 lb/hr), the unit would be a standard pre-engineered boiler with combustor. For a steam flow range of 12.6 to 27.7 kg/sec (100,000 to 220,000 lb/hr), the unit would be a customized pre-engineered boiler. Above this capacity, the unit would be a fully field erected customized boiler.

The annualized costs for CO boilers were developed according to EPA factors as shown in Table 6-2.[1,3,4,5] According to Figure 3-19, annualized costs decrease (i.e., a net savings is realized) as the steam flow rate increases. This savings results from the steam credit figured into the costs. Although the graph does not show it, at very low steam rates (corresponding to relatively small CO boilers) the annual costs are expected to be positive.

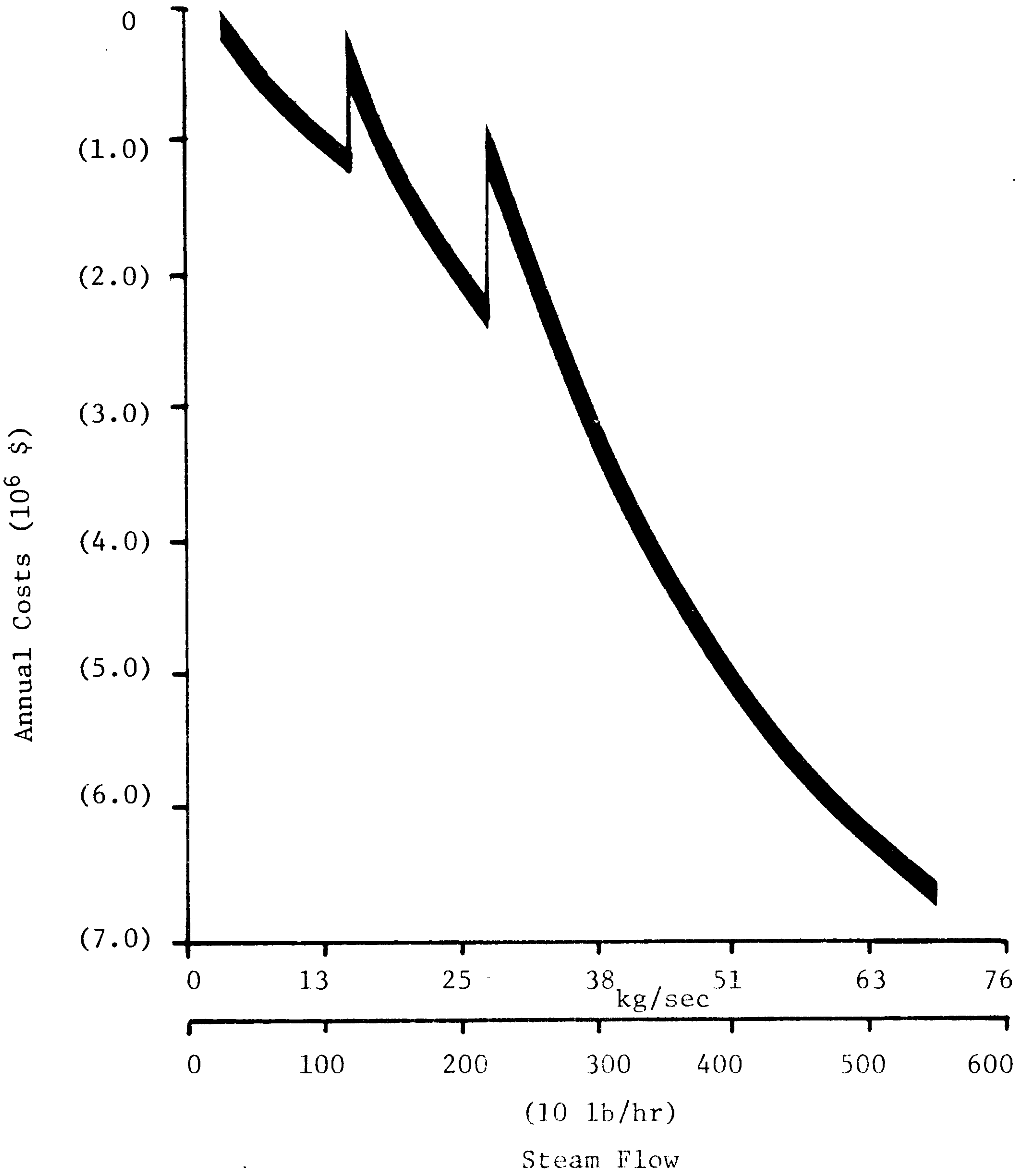
6.3 FLARES AND PLUME BURNERS

Flares and plume burners are devices which thermally incinerate waste gases, in this case carbon monoxide, with no recovery of heat. The primary distinction between a flare and a plume burner is the amount of supplemental fuel necessary to maintain combustion. A flare requires some degree of supplemental fuel for continued operation, while a plume burner is completely



Source: Reference 5

FIGURE 6-16. INSTALLED EQUIPMENT COST FOR CARBON MONOXIDE BOILERS (mid-1978 dollars)



Source: Reference 1, 3, 4, 5,

FIGURE 6-17. ANNUAL COSTS FOR CARBON MONOXIDE BOILERS (mid-1978 dollars) self-supporting. In the past flares and plume burners have been most commonly used as safety devices to incinerate waste gases from petroleum refining and petrochemical manufacturing operations. More recently other industries, such as carbon black manufacturing, have also been using flares and plume burners for disposing of waste gases.

The effectiveness of flares or plume burners for reduction of CO emissions is uncertain because there is no data on emission control.[6] This is because the combustion gases are discharged into the atmosphere making it difficult to sample the unconfined gases.[6]

REFERENCES FOR CHAPTER 6

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6. Flare Systems Study, PB-251-664, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, March 1976.

7. INDUSTRIAL PROCESS SOURCE CONTROL

Carbon monoxide emissions and controls for industrial process sources are discussed in this chapter. The industrial sources chosen for characterization include carbon black production, charcoal manufacture, the organic chemical industry, the iron and steel industry, petroleum refining, primary aluminum smelting, and the pulp and paper industry. Process descriptions are given in enough detail to indicate where emissions are produced, and emission quantities are estimated for each source. Currently applied control technology and feasible control methods are discussed, as are control efficiencies, energy requirements, costs, and environmental impact.

7.1 CARBON BLACK INDUSTRY

Carbon black is produced by the partial oxidation of hydrocarbons in a limited supply of air. The primary use of carbon black is in the production of rubber where it acts as a reinforcing agent. Currently about 95 percent of all carbon black produced in the U.S. is used by the rubber industry.[1] It is also used as a colorant for printing ink, paint, paper, and plastics.[1]

The most recent estimates available indicate that in 1977 about 2.2 million metric tons (2.4 million tons) of carbon monoxide were emitted from carbon black production in the U.S.[2] The following sections include a brief process description of carbon black production and an assessment of carbon monoxide control technology for the carbon black industry.

7.1.1 Process Description

There are three basic processes used in the United States for the production of carbon black. They are: the furnace process, the channel process, and the thermal process. Production from the furnace process accounts for about 90 percent of the total tonnage of carbon black produced.[3] Almost 10 percent is produced from the thermal process and less than 0.1 percent from the channel process.[3]

Thermal process plants use a relatively clean feedstock and can recycle almost all of the off-gas to reactors to recover the energy in the gas. Because recycle is a part of the thermal process, carbon monoxide emissions from this process are insignificant.[4,5]

In 1974, only one plant producing carbon black via the channel process was still in operation, and it was subject to a court order requiring gradual closure by 1979.[3] Because this process has been almost totally phased out, carbon monoxide emissions from it are not discussed in this document.

In the furnace process, mixed feeds of a light hydrocarbon gas and a heavy oil are used in most plants. The best oil to use for the production of modern high structure carbon blacks is highly aromatic, low in sulfur, contains high molecular weight resins and asphaltenes, and is substantially free of suspended ash and water.[1] The mixed feed is preheated and injected with a limited supply of combustion air into the reactor or furnace.

Internal reactor temperatures vary from 1300-1700°C (2400-3100°F), depending on the grade of carbon black being produced.[6]

The flue gases and entrained carbon from the reactor are cooled to 540°C (1000°F) by heat exchange with the furnace feed and sent to a water quench tower.[6] The carbon black laden gas stream is then sent to a fabric filter unit for product recovery. The gaseous effluent contains approximately 50 percent water vapor and 35 percent nitrogen. The remaining 15 percent is made up of CO, CO_2, and H_2, with small amounts of methane and acetylene.[6]

The recovered carbon black is sent to a small collecting cyclone and is then fed to a micropulverizer to break up any hard agglomerates present. The pulverized carbon black is sent to a finishing area where final processing yields a pelletized or bead product. Figure 7-1 is a simplified flow diagram for the furnace type carbon black process.

7.1.2 Process Emission Sources and Factors

In the furnace process, the gas stream containing the carbon black also contains significant quantities of carbon monoxide. After the carbon black has been removed, this stream is usually discharged to the atmosphere through a vent stack. This vent is the source of the carbon monoxide emissions from the furnace process. Table 7-1 contains a representative vent gas composition.[1] Actual vent gas composition can vary considerably from the average figures shown, depending primarily upon the grade of carbon black being produced. CO emissions tend to be higher for small-particle carbon black production.[1]

The uncontrolled carbon monoxide emission factor for the furnace process as reported by EPA is 1300 kilograms/metric ton of black produced

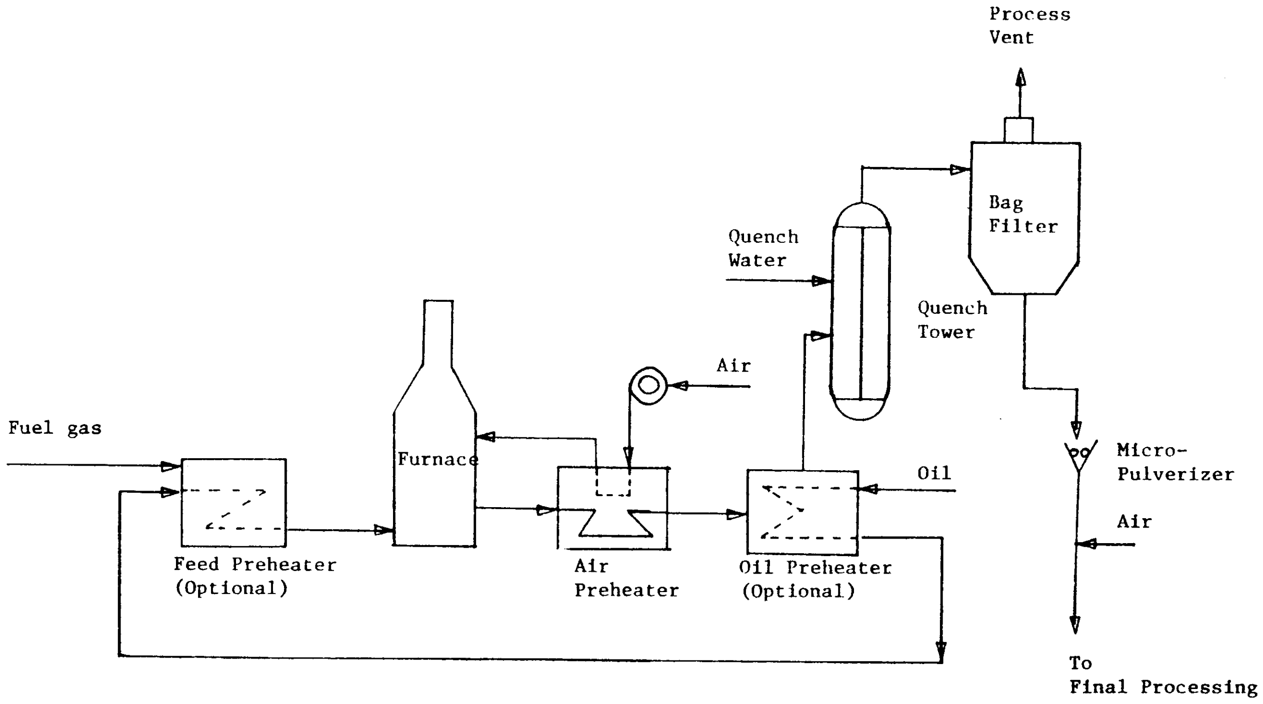


FIGURE 7-1. FLOW DIAGRAM FOR A FURNACE TYPE CARBON BLACK PLANT

TABLE 7-1

TYPICAL VENT GAS COMPOSITION FOR CARBON BLACK FURNACE OIL PROCESS

COMPONENT	RANGE IN COMPOSITION MOLE %	TYPICAL COMPOSITION MOLE %
Hydrogen	5.5 - 15	6.7
Carbon Dioxide	3 - 6.5	2.5
Carbon Monoxide	6 - 14	5.5
Hydrogen Sulfide	0.01 - 0.2	0.1
Methane	0.2 - 0.7	0.2
Acetylene	0.1 - 1.0	0.2
Nitrogen & Argon	65 - 80	35.5
Oxygen	0 - 4.9	0.3
Nitrogen Oxides (NO_2)	15 - 200 ppm(a)	44 ppm
Water	(b)	49.0

(a) High values represent values from two plants. Most producers believe actual value is toward low end of range shown.

(b) Dry basis. Stream typically contains 42-50 mole % water.

Source: Reference 1

(2600 lb/ton).[5] With a CO boiler or thermal incinerator for a control device, the reported emission factor is 5 kg/metric ton (10 lb/ton). These represent efficiencies of over 99 percent for the boiler or incinerator. There are no significant CO emissions from the thermal process.[4,5]

7.1.3 Control Techniques

In 1976, 29 carbon black plants were operating in the U.S. Of that number, three were equipped with CO boilers, two had thermal incinerators, and two were equipped with flares.[7] At that time, three additional plants were installing CO boilers.[7] Besides these control techniques, catalytic incineration represents a feasible but undemonstrated control alternative. The remainder of this section discusses the application of these control techniques to carbon black plants.

7.1.3.1 CO Boilers

The CO boiler is one method of controlling combustible gaseous emissions. However, the addition of a CO boiler to any existing carbon black plant would be costly. This is because most plants have electric-powered motors to drive their equipment and thus cannot use the generated steam without a large expenditure for turbine drivers.

Approximately 50 to 60 percent of the steam generated by off-gas combustion in a new carbon black plant can be used in the process to drive steam turbines and to supply steam for other uses.[7] Consequently, CO boilers are not used to generate steam beyond this level, unless other outlets for the steam are available.

To ensure complete combustion of the CO in the vent gas, boilers are normally designed for combustion zone operating temperatures of 870-980°C

(1600-1800°F).[1] If all the energy in the vent gas is not needed for steam production, a CO control system can be installed. In typical systems, part of the vent gas is used as CO boiler fuel and the remaining portion is sent to a thermal incinerator or flare. The excess gas may also be used as fuel for drying carbon pellets.

Testing at two carbon black plants found the carbon monoxide emissions from CO boilers ranged from 0.001 to 0.005 kg/metric ton of carbon black (0.002-0.010 lb/ton).[7]

Additional problems associated with the application of CO boilers to carbon black plants include:[1]

a) The vent gas is at low pressure, and has a high water vapor content.

b) The gas stream is corrosive.

c) Up to 35 percent of the total heating value of the gas burned in the boiler must be added as supplemental fuel in order to achieve complete combustion.

d) Flameouts causing safety problems are possible due to flame control difficulty.

e) A dependable steam supply may require a spare boiler.

f) Frequently, the type of carbon black produced is changed. This requires the complete plant system to be purged. During this time total supplemental fuel firing of the boiler is necessary because the vent gas has no heating value. Bringing the boiler back on line when the new type of carbon black is first being produced is difficult.

7.1.3.2 Flares

As of 1976 two domestic carbon black manufacturers reported the use of vent gas flares.[7] According to the operator of one plant, the minimum self-supporting heating value is about 1.87 megajoules/Nm^3 (50 Btu/scf).[1] The typical heating value for carbon black vent gas has been reported to be only 1.49 megajoules/Nm^3 (40 Btu/scf).[1]

With respect to their application to carbon black plants, flares have the following limitations:[1]

a) The burner could be extinguished due to relatively small changes in the vent gas composition if supplemental fuel and adequate instrumentation are not provided.

b) The CO control effectiveness of a flare cannot be measured accurately because it is necessary to sample and measure gas flow after the gases leave the stack outlet and mix with ambient air. (See Section 6.3.)

7.1.3.3 Thermal Incinerator

A thermal incinerator which utilizes heat recovery by preheating the air and vent gas in a heat exchanger with the products of combustion will not require supplemental fuel.[1] This is true for virtually all carbon black plants.

To achieve adequate oxidation of the carbon monoxide, the combustion zone temperature should be between 870-980°C (1600-1800°F).[1] These temperatures should result in CO removal efficiencies of over 95 percent.

In 1976, two U.S. plants were known to use thermal incineration for control of the vent gas emissions.[7] At one plant, more excess air is used than is normal (7 vs. 4 mole % O_2) and there is no air preheat. For these reasons, supplemental fuel is required for this unit.

7.1.3.4 Pellet Dryers

Vent gas may also be used as a fuel for drying carbon pellets. However, supplemental fuel would be necessary to maintain combustion. Carbon monoxide concentrations of less than 10 ppm have been measured from the exhaust of a pellet dryer using vent gas as a fuel.[7]

7.1.3.5 Catalytic Incinerator

As of 1976 no carbon black plants were using catalytic incineration to burn their process vent gases.[7] However, it has been reported that one attempt was abandoned some years ago because of catalyst poisoning.[1] If a catalyst is used that is not poisoned by sulfur, and adequate control instrumentation is employed to prevent high bed temperatures, it should be possible to use a catalytic incinerator.[1]

A 490°C (900°F) inlet temperature to the catalytic bed should be sufficient to oxidize almost all carbon monoxide in the vent gas.[1] Maximum temperature within the bed should be limited to 650°C (1200°F) in order to prevent damage to the catalyst and a resulting loss in catalyst activity. As the catalyst ages, though, its combustion efficiency will gradually decrease due to a loss in activity. At the time when excessive pollutant concentrations begin to be discharged from the incinerator, the catalyst bed must be replaced.

7.1.4 Cost of Controls

Chapter 6 contains a more detailed presentation of capital and annualized costs for the carbon monoxide control techniques described above. Both types of costs are presented graphically in terms of dollars per normal cubic meter per second ($/scfm) with several curves per graph showing the effect of the heating value of the gas being oxidized on the annualized costs. Therefore, given a representative flow rate and heating value for the vent gas from a carbon black plant, various control costs can be estimated.

As mentioned earlier, the heating value of the vent gas is typically 1.49 megajoules per normal cubic meter (40 Btu/scf). A representative vent gas flow rate for a 41,000 metric tons/yr (45,000 tons/yr) carbon black plant is about 27 Nm^3/sec (57,400 scfm).[1] This corresponds to a vent gas flow rate of approximately 20.9×10^3 Nm^3 per metric ton (0.67×10^6 scf/ton) of carbon black produced.[1]

7.1.5 Impact of Controls

The following presents information on the impact of applying the control techniques discussed earlier to the vent gas stream from carbon black production. Potential reductions in carbon monoxide emissions, environmental impact, and energy requirements for each of the controls are addressed.

7.1.5.1 Emissions Reduction

The main process vent is the primary source of carbon monoxide emissions from carbon black plants. As of 1976, 25 percent of the plants (7 plants) employed controls for this source.[7] Assuming retrofit of the remainder of the plants with control devices such as a CO boiler or incinerator with a CO control efficiency of 99 percent, annual carbon monoxide emissions could be reduced from this industry by about 2.18×10^6 metric tons (2.38×10^6 tons).

7.1.5.2 Environment

The application of controls for the CO emissions from carbon black plants will have both positive and negative impacts with respect to other pollutant discharges. The positive impact will include the oxidation of the combustible components other than CO in the vent gas (hydrogen, H_2S, methane, acetylene and most of the particulate carbon black which penetrated the fabric filters).[6]

The negative impact will include increased emissions of NO_x from all the control techniques described, conversion of some SO_2 in the gas to SO_3 in the catalytic incinerators if noble metals are used, and increased SO_2 emissions if oil is used as a supplemental fuel in the oxidation systems.

Increased NO_x emissions will depend on the operating temperature of the oxidation system being used. Reported increase in the NO_x levels in the vent gas after being oxidized in a thermal incinerator is about 4.8 grams of NO_x per Nm^3 of vent gas (3 lb/10,000 scf).[1] For catalytic incineration it is about 1.6 grams per Nm^3 (1 lb/10,000 scf).[1] Because CO boilers perform the function of providing plant energy as well as pollution reduction, no incremental emissions are attributed to CO boilers. Without the CO boiler, energy would have to be generated elsewhere and purchased by the plant. This would result in roughly equivalent quantities of combustion-related pollutant emissions.

7.1.5.3 Energy Requirements

The energy requirements associated with the application of CO controls to carbon black plants will vary significantly from plant to plant due to the variations in vent gas composition and heating value. Assuming a typical vent gas heating value of 1.49 megajoules/Nm^3 (40 Btu/scf), energy requirements for the various controls can be calculated.

Thermal and catalytic incinerators with heat recovery designs will require no supplemental fuel. A CO boiler fueled with vent gas with a heating value of 1.49 megajoules per Nm^3 (40 Btu/scf) will require approximately 7.9 megajoules of supplemental fuel per kilogram of carbon black (3,400 Btu/lb) produced at the plant.[1] If the vent gas is sent to a flare stack for oxidation of the CO, approximately 42.8 megajoules of supplemental fuel per kilogram of carbon black (18,400 Btu/lb) will be required.[1] These calculations are based on an average vent gas flow of 19 Nm^3/kg of carbon black (300 scf/lb).[1]

7.2 CHARCOAL INDUSTRY

Charcoal is manufactured by the pyrolysis (carbonization or destructive distillation) of carbon-containing materials. Raw materials can be almost any carbon-containing material but are principally medium to dense hardwoods such as beech, birch, hard maple, hickory, and oaks. Wood charcoal is used primarily as a recreational cooking fuel.

The most recent national emission estimates indicate that in 1977 about 97,300 metric tons (107,200 tons) of carbon monoxide were emitted from charcoal manufacturing.[2] Calculations based on these numbers and the uncontrolled carbon monoxide emission factors for charcoal manufacturing indicate that more than seventy percent of U.S. charcoal plant production has no carbon monoxide emission controls. The following sections include a brief process description, identification of charcoal plant carbon monoxide emission sources, and an assessment of carbon monoxide control technology for the charcoal industry.

7.2.1 Process Description

Two basic processes exist in the charcoal manufacturing industry: batch kilns and continuous multiple-hearth furnaces. Of the total yearly production of charcoal in 1975, approximately 55 percent was produced by the continuous process and 45 percent by the batch process.[8] Because the two differ significantly, two process descriptions are given.

7.2.1.1 Batch Process

The present day batch process incorporates two types of charcoal kilns. The most widely used is the Missouri type shown in Figure 7-2.

The Missouri type kiln is usually constructed of concrete, typically processing 45 to 50 cords of wood per cycle. A cycle includes loading the kiln, carbonizing the wood, allowing the charcoal to cool, and unloading the kiln. Time requirements for each component of the cycle differ greatly from plant to plant; however, the overall time period involved in a normal cycle is about 6 to 25 days.[9]

Once started, maintaining proper conditions in the kiln is the primary requirement for satisfactory carbonization. Sufficient heat must be generated to first dry the wood and then to maintain temperatures necessary for efficient carbonization. Combustion of a part of the wood volatiles generates the heat to sustain the carbonization process. By varying the size of the air port openings providing air for the combustion of these wood volatiles, control of the kiln temperature is achieved. Kiln temperatures

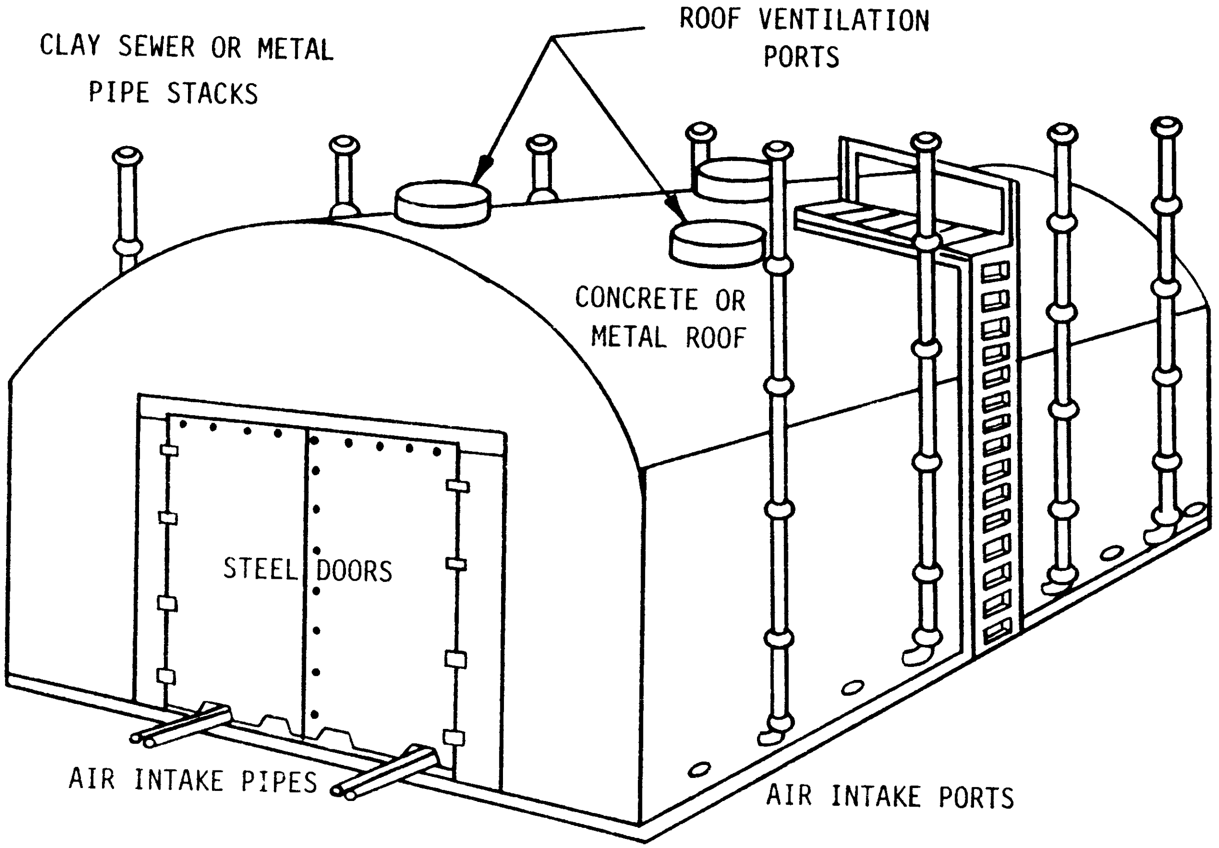


FIGURE 7-2. TYPICAL MISSOURI-TYPE CHARCOAL KILN WITH MULTIPLE EXHAUST STACKS

of from about 840-950°C (1540-1740°F) are required for the production of good quality charcoal.

The second type of batch kiln used presently is the beehive kiln which is shown in Figure 7-3. This kiln is usually constructed of concrete and consists of a cylindrical wall with a dome-shaped ceiling. The kiln structure includes ground-level air and mid-level exhaust ports located around the periphery of the wall, a steel door in the side of the wall for loading and unloading, and an opening in the dome-shaped ceiling for loading and firing. Beehive kilns typically process 50 to 90 cords of wood per cycle. The time period involved in a normal cycle is about 10 to 20 days.

7.2.1.2 Continuous Process

The Herreshoff multiple hearth furnace is the predominant continuous charcoal process in use today. This process is gaining a larger share of the total charcoal production yearly.[9]

The Herreshoff multiple hearth furnace consists of several hearths or burning chambers stacked one on top of the other as shown in Figures 7-4 and 7-5. The hearths are contained in a cylindrical, steel, refractory-lined shell, and are divided by refractory decks which function as the floor of one hearth and the roof of the hearth below. Passing up through the center of the furnace is a shaft to which two or four rabble arms per hearth are attached. As the shaft turns (usually 1 to 2 rpm), the hogged (chipped) material resting on the hearth floors is continually agitated, exposing fresh material to the hot gases being evolved. Another function of the rabble arms is to move material through the furnace. On alternate hearths the teeth

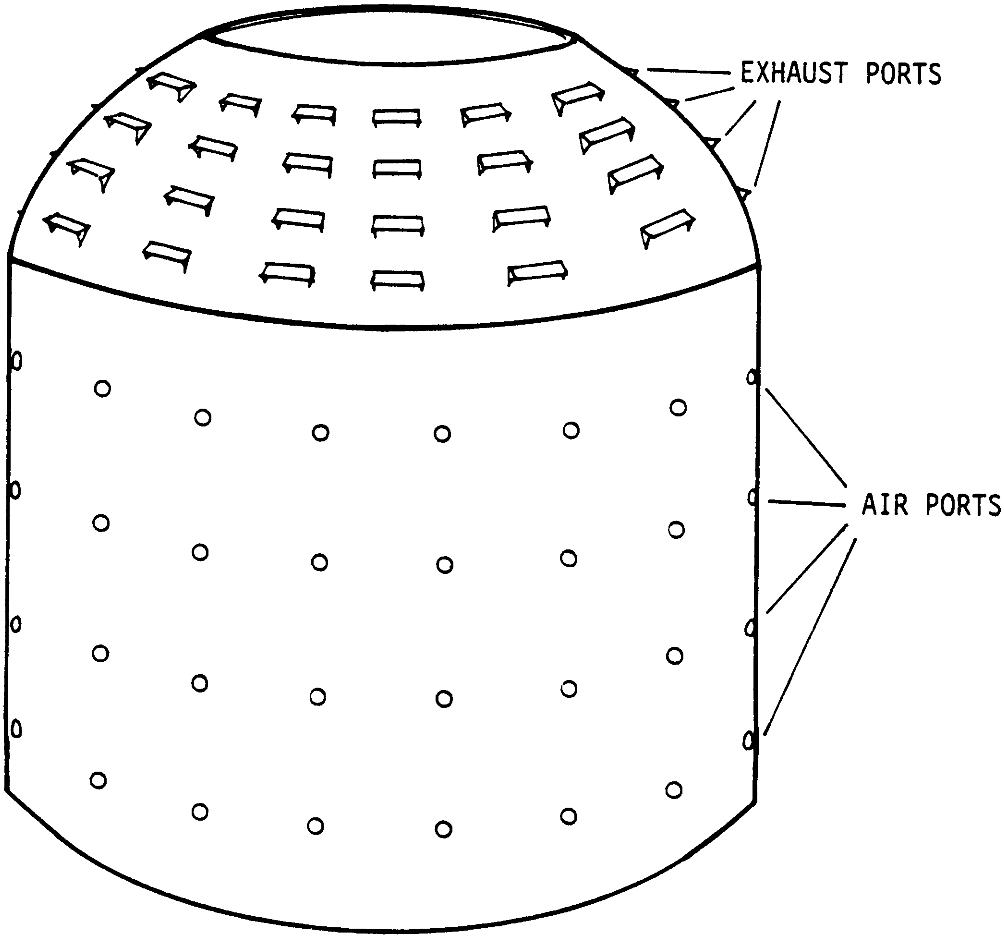


FIGURE 7-3. TYPICAL BEEHIVE KILN

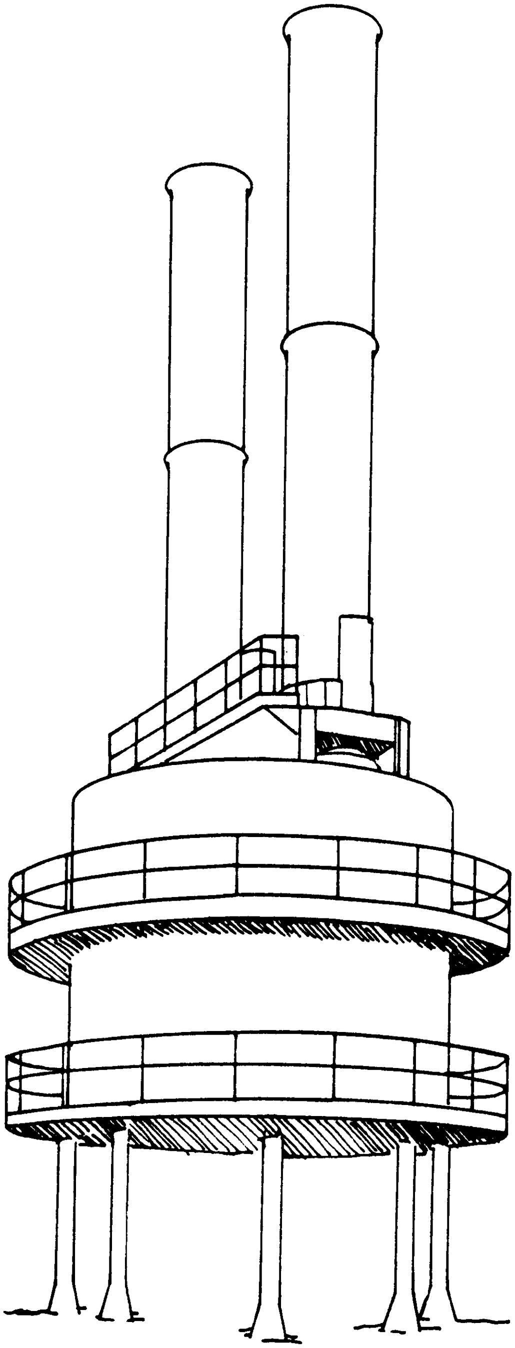


FIGURE 7-4. EXTERIOR VIEW OF A HERRESHOFF MULTIPLE HEARTH FURNACE

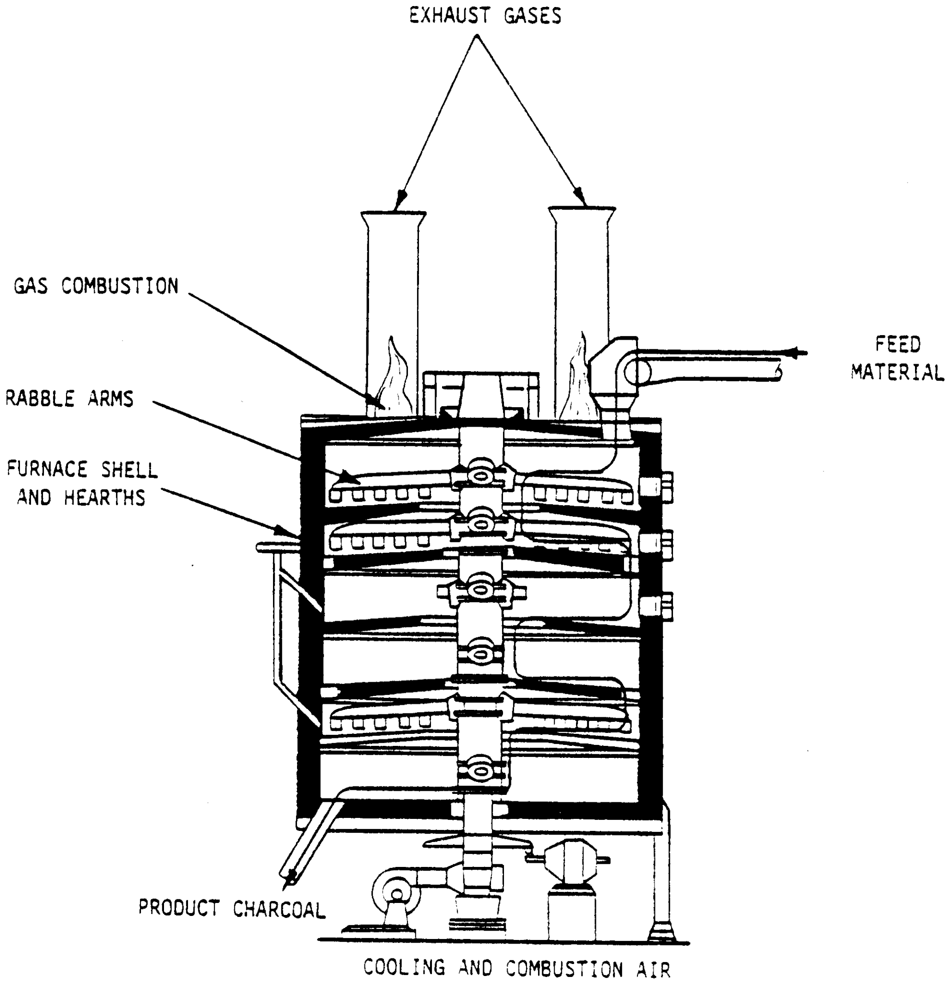


FIGURE 7-5. CROSS SECTIONAL VIEW OF A HERRESHOFF MULTIPLE HEARTH FURNACE, WITH PLUME BURNING

are canted to spiral the material from the shaft toward the outside wall of the furnace or from the outside wall toward the center shaft. Around the center shaft is an annular space through which material drops on alternate hearths, while on the remaining hearths material drops through holes in the outer periphery of the hearth floor. In this way, material fed at the top of the furnace moves alternately across the hearths at increasing temperatures until it discharges from the floor of the bottom hearth. Furnace temperatures range between 450°C and 650°C (840°F and 1200°F).

All off-gases exit from above the top hearth. These gases are either flared directly to the atmosphere through stacks located on top of the furnace as shown in Figure 7-5, or they may be further processed to use the available heat for predrying the incoming feed material, drying briquettes produced at an adjacent briquetting plant, or for producing steam in an adjacent waste heat steam boiler.

Multiple hearth furnaces require a large and steady source of raw materials. This limits their use to areas where many small or a few large sawmills and other wood waste producers are located. This criteria also eliminates the chance of replacing all batch-type processes with multiple hearth furnaces since most batch-type plants as well as their raw material sources are located in isolated areas.

7.2.2 Process Emission Sources and Factors

Large amounts of carbon monoxide are formed by the partial oxidation mechanisms within both batch kilns and continuous operating furnaces. An emission factor of 160 kilograms of CO per metric ton charcoal (320 lb/ton) has been reported for carbon monoxide emissions from charcoal production.[5] No distinction is made between carbon monoxide emission rates from batch and continuous processes. However, it is reasonable to expect that due to the higher operating temperatures in the continuous process, there will be lower carbon monoxide emissions per unit weight of charcoal produced.

7.2.3 Control Techniques

Conditions for CO control on batch processes are different than for continuous processes. Gas or oil-fired thermal incinerators are the only methods employed for control of emissions from batch process plants. Most batch process plant emissions are uncontrolled. CO emissions from continuous process plants can be controlled with thermal incinerators. At times flares are used. All continuous process plants employ either one or a combination of these two methods. Applications of controls to batch and continuous processes are discussed separately below.

7.2.3.1 Control of Batch Processes

Control of emissions from batch charcoal kilns is difficult due to the cyclic nature of the process and, as a result, the cyclic nature of the emissions. During the carbonization cycle, both the emission composition and discharge rate vary. Typically, emission rates peak early in the cycle at a flow rate over 40 percent greater than the flow rate near the end of the cycle.[8] Variations in the type of feed material, the moisture content of the feed material, and the operating practice also influence emission composition and rate.

A direct fired thermal incinerator is the only method used to control emissions from batch kilns. Afterburner temperatures of over 750°C (1400°F) with a residence time of 0.2 to 0.4 seconds are required to achieve efficient oxidation of carbon monoxide.[10]

Existing control systems have been designed primarily to reduce visible emissions (particulates and hydrocarbons) instead of CO. In a typical operation, each incinerator, directly fired with natural gas or oil, services two or more kilns. A temperature of about 650°C (1200°F) is maintained in the incinerator during the kiln burn by automatic controls which cycle the fuel fed to the afterburner on and off. The afterburner is then shut down as soon as the kiln burn is complete.[9] To provide at least 90 percent efficient CO control, these systems would have to be modified to operate at a temperature of about 980°C (1800°F).[9] This modification would increase the requirement for supplementary fuel and perhaps require incinerator redesign.

Problems associated with the application of incinerator systems to batch kilns include the following:

a) The design and operation of batch kilns must be modified to accommodate the application of incinerators. The multiple exhaust pipes or ports (as shown in Figures 7-2 and 7-3) must be converted to one large exhaust manifold. Because of this requirement, applications to beehive kilns would be costly.

b) Plants with kilns mounted far apart or on unlevel land must install long lengths of costly ductwork to connect the kilns to the incinerators.

c) The control systems consume large quantities of supplementary fuel during periods of the kiln burn.

7.2.3.2 Control of Continuous Processes

Herreshoff furnaces generate an off-gas with a relatively constant composition and flow rate. As a result, control of emissions is easier with the Herreshoff furnaces than with Missouri kilns.

The furnace off-gas can be burned in refractory-lined stacks on top of the furnace by admitting combustion air through adjustable doors in the base of the stack, as shown in Figure 7-5.[8,11] With dry feed the heating value of the off-gas is sufficient to maintain temperatures ranging from 750 to 850°C (1400-1550°F).[12] The most efficiently controlled plants are equipped with wood dryers for removing free moisture prior to the Herreshoff furnace. Table 7-2 shows off-gas characteristics for a plant equipped with a wood dryer. The off-gases from the Herreshoff furnace are used for both wood and briquette drying. The remainder of the off-gas is discharged from the furnace stack. The accuracy of the CO emission data shown are poor because Orsat CO analyses are inaccurate at low CO concentrations. If a continuous type plant is not equipped with a wood dryer, it would be necessary to apply an afterburner to achieve the outlet temperatures shown in Table 7-2.

7.2.4 Cost of Controls

The control technique identified for batch and continuous processing charcoal kilns was thermal incineration. Chapter 6 contains a detailed presentation of capital and annualized costs for this control technique.

TABLE 7-2

CHARACTERISTICS OF OFF-GASES FROM A HERRESHOFF FURNACE CHARCOAL PLANT

Capacity: 1.9 Kilograms of Dry Wood per Second (7.5 tons/hr)[a]

	FURNACE STACK	WOOD DRYER STACK	BRIQUETTING MACHINE STACK
CO-PPM[b]	3000-5000	9800	0
O_2-%	6.0-9.9	16.2	18-19.7
°C	750-850	65	72
(°F)	(1400-1550)	(150)	(162)
Stack gas volume			
Actual cubic meters per second	49.6-73.1	11.0-12.0	10.6
(ACFM)	(105,000-155,000)	(23,200-25,400)	(22,500)
Stack gas velocity			
Actual meters per second	5.9-8.7	18.7-20.5	13.8
(AFPM)	(1160-1700)	(3700-4000)	(2700)
Stack diameter			
Meters	3.28	0.86[c]	1.17x0.66[c]
(Inches)	(129)	(34)	(46 x 26)

[a] Feed free moisture-50 percent by weight

[b] Orsat analysis

[c] Dimensions of one of two stacks

Source: Reference 12

To accurately determine the costs of applying these controls to batch type charcoal plants requires data on the off-gas flow rates and composition. No information was found from which flow rates of batch type charcoal kiln off-gases could be calculated.

7.2.5 Impact of Controls

The following discusses potential reductions in carbon monoxide emissions from the carbon monoxide control techniques identified in Section 7.2.3, as well as the environmental impacts and energy requirements of these controls.

7.2.5.1 Emission Reductions

The current level of control of charcoal kiln off-gases is unknown. Consequently, even an approximation of the potential reduction of CO emissions from the charcoal industry cannot be made.

7.2.5.2 Environment

The application of controls on charcoal plants for CO will result in the oxidation and control of virtually all hydrocarbons in the gas as well as most of the combustible particulates.

The operation of these controls, though, will result in an increase in NO_x emissions. However, this increase is not expected to be substantial if the flame temperatures are kept below 980°C (1800°F).

7.2.5.3 Energy Requirements

The application of CO controls to batch kilns will require fuel. Supplementary fuel requirements vary depending on the moisture content of the raw material used, the type of fuel used in the afterburner, climatic factors, and operating methods. Fuel oil consumption has been reported to average about 3.3 megajoules/kilogram of char (2.8 x 10^6 Btu/ton of char) during the summer and about 6.6 megajoules/kilogram of char (5.7 x 10^6 Btu/ton of char) during the winter.[9]

The off-gases from continuous charcoal kilns are of a high enough heat content so that no supplementary fuel is required for their oxidation. The recoverable heat content of the gas is about 29 megajoules per kilogram of charcoal produced (25 million Btu/ton).[13,14] This heat can be used to predry raw material fed to the carbonizer or for briquette-drying.

7.3 ORGANIC CHEMICAL INDUSTRY

Substantial amounts of carbon monoxide are emitted from organic chemical processes, which partially oxidize hydrocarbons derived primarily from petroleum, coal, and natural gas into organic intermediates and products. The processes producing the largest amounts of CO are acrylonitrile, formaldehyde, maleic anhydride, and phthalic anhydride production. CO is also produced from incineration of unmarketable by-products.

Mass carbon monoxide emissions from these processes are shown in Table 7-3. Smaller amounts of carbon monoxide are emitted from many other organic chemical processes which are not discussed in this report.

Carbon monoxide emissions from the four organic chemical processes discussed in this section comprised about 76 percent of 1977 CO emissions from the U.S. petrochemical industry, 4.4 percent of the CO emitted from U.S. industrial processes, and 2.1 percent of the total amount emitted in the U.S. from stationary sources.[2]

TABLE 7-3

MASS EMISSION ESTIMATES FOR CARBON MONOXIDE FROM FOUR ORGANIC CHEMICAL PROCESSES, 1977

SOURCE	CARBON MONOXIDE EMISSIONS	
	Metric tons	Tons
Acrylonitrile production	130,400	143,700
Formaldehyde production	64,900	71,500
Maleic anhydride production	117,800	129,900
Phthalic anhydride production	50,900	56,100
TOTAL	364,000	401,200

Source: Reference 2

7.3.1 Acrylonitrile

Acrylonitrile is an important feedstock in the production of synthetic fibers and in the treatment of natural fibers to improve their properties. Acrylonitrile is also used extensively in the production of low cost, multipurpose plastics, barrier resins, and nitrile rubber.

1977 EPA estimates indicate that 130,400 metric tons (143,700 tons) of carbon monoxide were emitted in the United States.[2] The extent and type of emission control varies widely within the industry.

7.3.1.1 Process Description

Acrylonitrile is produced in the U.S. by the Sohio fluid bed catalytic process. Figure 7-6 is a simplified flow sheet of the process. Air, ammonia, and propylene are fed to a reactor at 140-310 kilopascals (5-30 psig) and 420-530°C (780-980°F) to form acrylonitrile. The chemical reaction is shown in the equation below.

$$2\ CH_2 = CH - CH_3 + 2\ NH_3 + 3O_2 \rightarrow 2\ CH_2 = CH - CN + 6\ H_2O$$

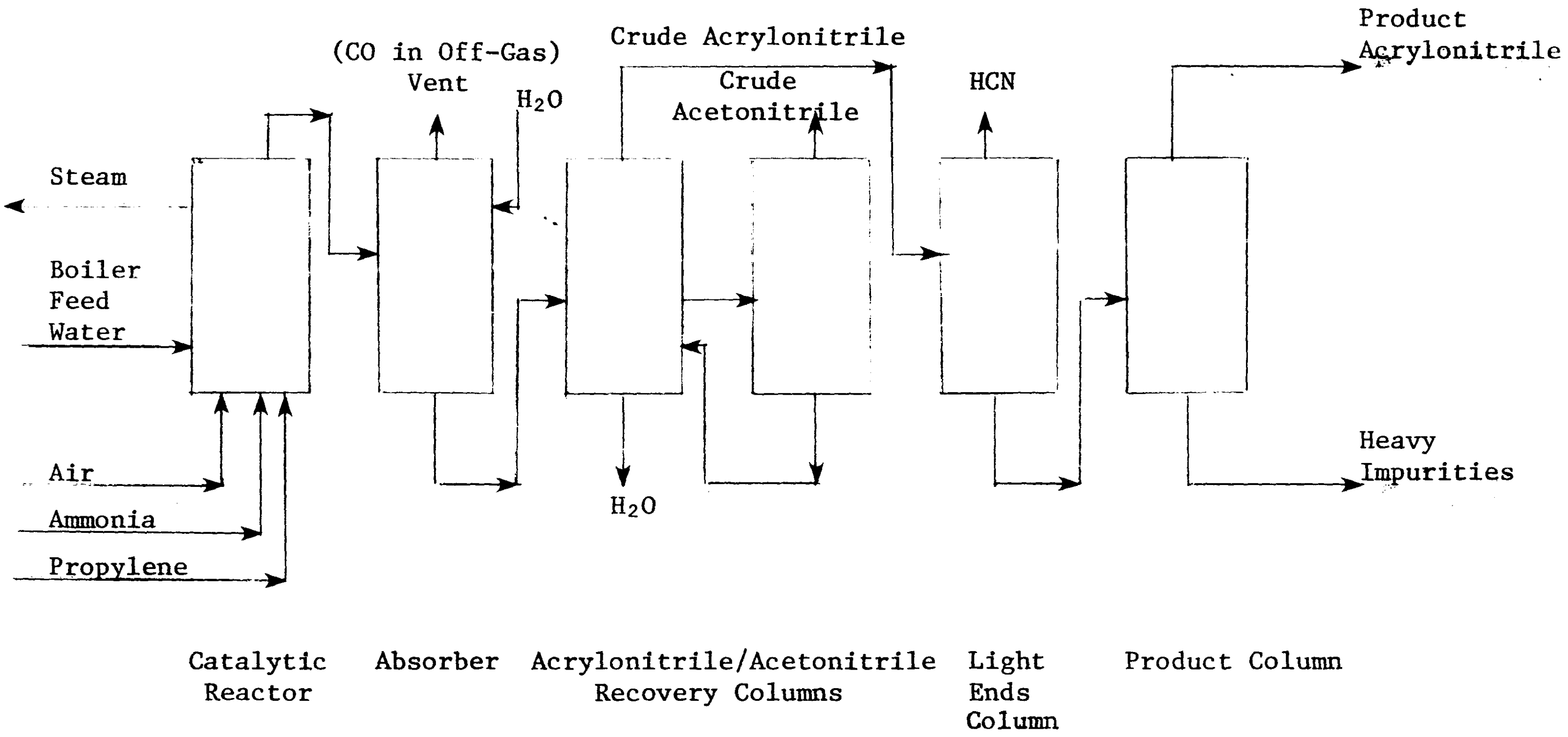


FIGURE 7-6. FLOW DIAGRAM FOR ACRYLONITRILE PRODUCTION VIA THE SOHIO PROCESS

No recycle is required, as the reaction is virtually complete. Reaction products are recovered in a water absorber-stripper system. Acrylonitrile is then separated from by-products in a series of distillations. The first fractionation of crude acrylonitrile usually removes HCN as an overhead stream. The acrylonitrile is then purified to 99+ percent in further distillation steps. The wet acetonitrile by-product is subjected to extractive distillation using water as the extractive solvent.

By-product streams may be processed to recover high purity HCN and acetonitrile for sale. The by-product streams which are not sold are incinerated. Currently, two acrylonitrile producers market acetonitrile.[15] All of the producers market HCN. Fifty percent of the HCN is sold, and the remaining 50 percent is incinerated or disposed of in deep wells.[16]

There have recently been two ammoxidation catalysts in use: Catalyst 21 and Catalyst 41. Although the yields are about the same for the two catalyst systems, Catalyst 41 provides for better utilization of ammonia and requires less oxygen. All U.S. acrylonitrile producers have switched to Catalyst 41.[16]

7.3.1.2 Process Emission Sources and Factors

The major source of CO emissions within acrylonitrile plants is the main process vent, which vents from the absorber. Currently, three acrylonitrile plants out of six in the U.S. apply CO emission control technology to emissions from their main process vents.[7] Absorber vent gas composition is affected by catalyst type, reactor operating conditions, absorber overhead temperature, reactor feed rates, and feed material composition. Catalyst type can especially influence CO emission rate. Prior to 1973, uncontrolled CO emissions from processes using Catalyst 21, a uranium-based catalyst, were estimated at 0.178 kg/kg (0.178 lb/lb) acrylonitrile.[16,17] When manufacturers switched to Catalyst 41, a bismuth phosphomolybdate catalyst, emission factors were reduced to 0.079 kg/kg (0.079 lb/lb) acrylonitrile.[17]

Controlled emission factors were derived using reported control device efficiencies and uncontrolled emission factors.[16,17] Both thermal and catalytic incinerators used as CO control devices have reported CO removal efficiencies of greater than 95 percent.[16,17] When this factor was applied to uncontrolled emission rates, controlled CO emissions from the main process vent were estimated to be less than 0.004 kg/kg (0.004 lb/lb) acrylonitrile when Catalyst 41 was used.

7.3.1.3 Control Techniques

Three U.S. acrylonitrile plants currently control CO emissions from their main process vents.[7] All use combustion devices (i.e., a catalytic incinerator or a thermal incinerator) to reduce emissions.[7] These two types of demonstrated controls are discussed in the following paragraphs.

Thermal Incinerators -- A schematic diagram of one of the three thermal incinerators currently used in U.S. acrylonitrile plants is shown in Figure 7-7.[17] This device is used for combustion of by-product acetonitrile and hydrogen cyanide as well as main process vent gas. The incinerator operates at 870°C (1600°F) and reportedly achieves >95 percent combustion of CO in the vent gas. Natural gas is used as a supplemental fuel because of the relatively low heating value of the vent gas (0.75-1.49 megajoules/m^3 [20-40 Btu/ft^3]).[17]

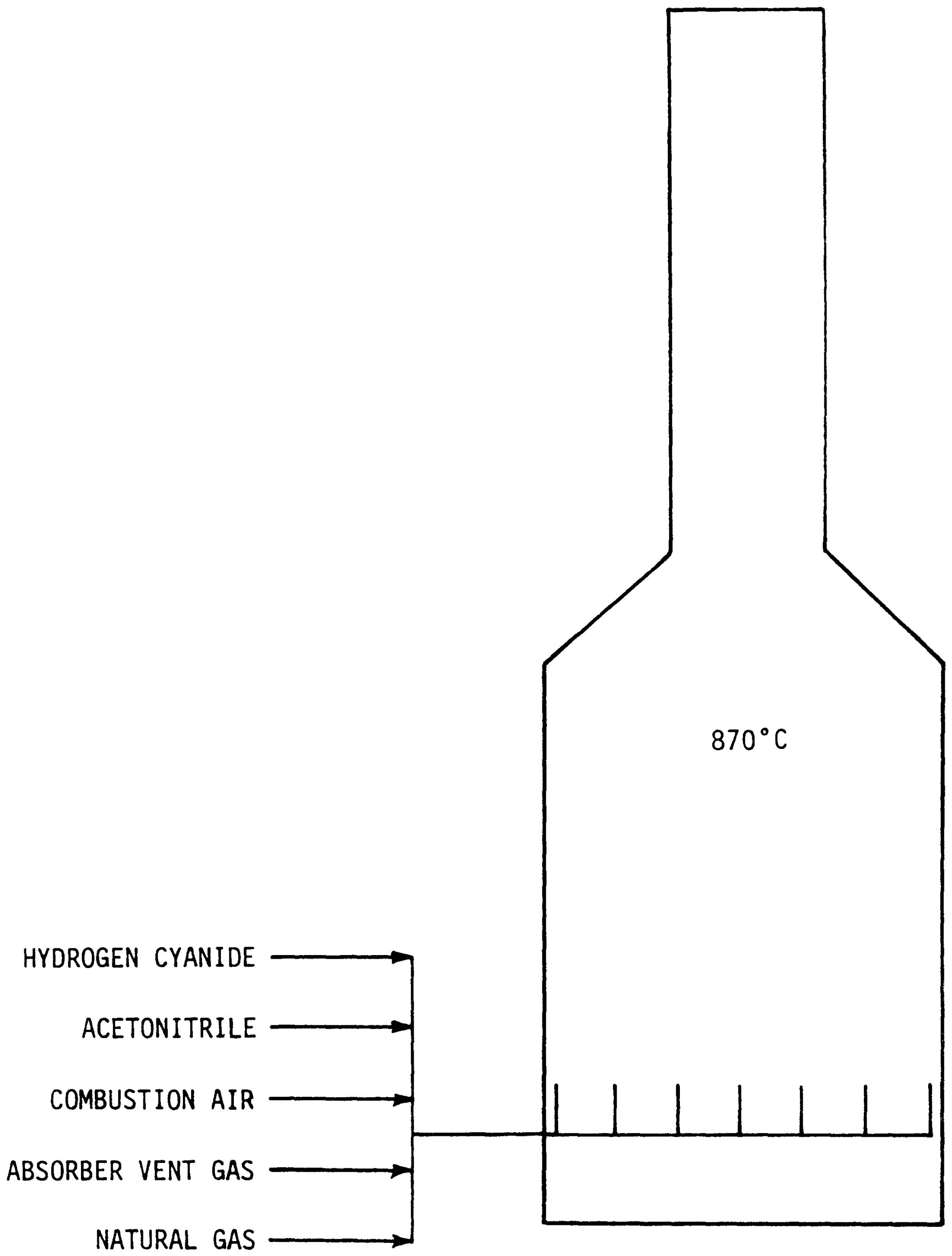


FIGURE 7-7. SCHEMATIC DIAGRAM FOR A COMBINATION BY-PRODUCT INCINERATOR/ ABSORBER VENT GAS THERMAL OXIDIZER SYSTEM

A similar thermal incinerator could be used to control CO emissions from the main process vent only. Typical main process vent gas composition is shown in Table 7-4. Operating temperatures range up to 980°C (1800°F); more complete combustion can be achieved with higher temperatures, but NO_x emissions increase rapidly at temperatures above 980°C (1800°F).

Catalytic Incinerators -- One U.S. acrylonitrile producer uses a catalytic incinerator to oxidize off-gas from its main process vent.[17] Operating parameters for this device have not been reported, but typical catalytic incinerators operate at temperatures ranging from 480-650°C (900-1200°F).[16] The effectiveness of this catalytic incinerator for reducing CO is not reported. The effectiveness of the unit for reducing hydrocarbon emissions is reported to be 42.5 percent.[7]

Because of their lower operating temperatures, catalytic incinerators use less supplemental fuel and tend to emit lower levels of NO_x than thermal incinerators. Their principal drawbacks are the moderate length of catalyst life, the tendency toward catalyst poisoning by off-gas components, and their increased operating and maintenance costs.

7.3.1.4 Cost of Controls

A detailed presentation of annualized costs for the above-mentioned carbon monoxide controls is given in Chapter 6. The following describes how this information can be applied to estimate the costs for controlling carbon monoxide emissions from acrylonitrile production. This can best be accomplished by taking a model plant and describing those parameters which will determine the annualized costs for controlling its CO emissions. These

TABLE 7-4

COMPOSITION OF MAIN PROCESS VENT GAS FROM ACRYLONITRILE PRODUCTION VIA THE SOHIO PROCESS

COMPONENT	VOLUME PERCENT
Carbon dioxide	2.6
Carbon monoxide	1.5
Propylene	0.3
Propane	0.5
Hydrogen cyanide	<0.1
Acrylonitrile	<0.1
Acetonitrile	0.1
Nitrogen	80.9
Oxygen	0.8
Water	13.3
Nitrogen oxides	<0.1

Source: Reference 17

parameters are vent gas flow per unit weight of acrylonitrile produced and the energy content of the vent gas.

The model is based on a new plant producing 9.1×10^4 metric tons (2.0×10^8 lb/yr) of acrylonitrile. Representative flow rates for the process vent gas from a plant this size have been reported to be 21 Nm^3/sec (45,000 scfm).[16] The energy content of this gas has been reported to be within a range of from 0.75-1.49 megajoules/m^3 (20-40 Btu/ft^3) with 0.89 megajoules/m^3 (24 Btu/ft^3) reported to be the most representative number.[17] Using this information and the information in Chapter 6, annualized costs can be estimated for the various applicable control techniques for an individual plant of a given size or for the entire industry.

7.3.1.5 Impact of Controls

Emissions Reduction -- The main process vent is the primary source of carbon monoxide emissions from acrylonitrile plants. Currently, emissions from three plants, or about 47 percent of the U.S. acrylonitrile capacity, are reportedly controlled.[16] It was calculated that application of incinerators or the other feasible CO controls could result in a reduction of annual carbon monoxide emissions of about 62,000 metric tons (68,600 tons), if 90 percent removal efficiency were achieved.

Environment -- When incineration is used as a means of CO emission control, the amount of NO_x in the incinerator flue gas increases. In general, higher incinerator temperatures result in higher NO_x emissions. No data were available regarding NO_x formation in catalytic incinerators. NO_x emissions from this device should be lower than for thermal incinerators because of the lower operating temperature.

At the present time, natural gas is generally used as supplemental incinerator fuel. If future shortages of natural gas require the use of fuel oil as supplemental incinerator fuel, an increase in sulfur oxides (SO_x) emissions would result. The magnitude of the SO_x emissions would depend on the sulfur level in the fuel oil and the total quantity of oil consumed.

Energy Requirements -- Both the demonstrated and undemonstrated techniques for CO emission control require the use of supplemental fuel. Energy content of the main process vent gas ranges from 0.75-1.49 megajoules/m^3 (20-40 Btu/ft^3).[16] The amount of supplemental fuel needed will vary with vent gas energy content and with the type of control device used.

Table 7-5 lists the amount of energy needed for thermal incinerators and waste heat boilers when used to control CO emissions from the main process vent. The calculations were based on a process vent gas energy content of 0.89 megajoules/m^3 (24 Btu/ft^3), from a 9.07×10^4 metric ton/yr (2.0×10^8 lb/yr) acrylonitrile plant.[17]

TABLE 7-5

ENERGY REQUIREMENTS FOR CO EMISSION CONTROLS IN ACRYLONITRILE PRODUCTION

CONTROL DEVICE	ENERGY REQUIRED(a)	ENERGY REQUIRED/ UNIT PRODUCT
Thermal incinerator without heat recovery or waste heat boiler	5.87 megajoules/sec (20×10^6 Btu/hr)	1.9 megajoule/kg (800 Btu/lb)

(a) Data from Reference 17, based on 8000 operating hours per year.

No information regarding catalytic incinerator energy requirements was available. However, this device uses less supplemental fuel than the other devices discussed above because its operating temperatures are substantially lower.

7.3.2 Formaldehyde

Formaldehyde is manufactured by two processes. One employs a silver catalyst and the other a mixed metal oxide catalyst. Approximately 23 percent of U.S. formaldehyde capacity is based on the mixed oxide process and 77 percent is based on the silver catalyst process.[18,19] Both processes are described below.[20]

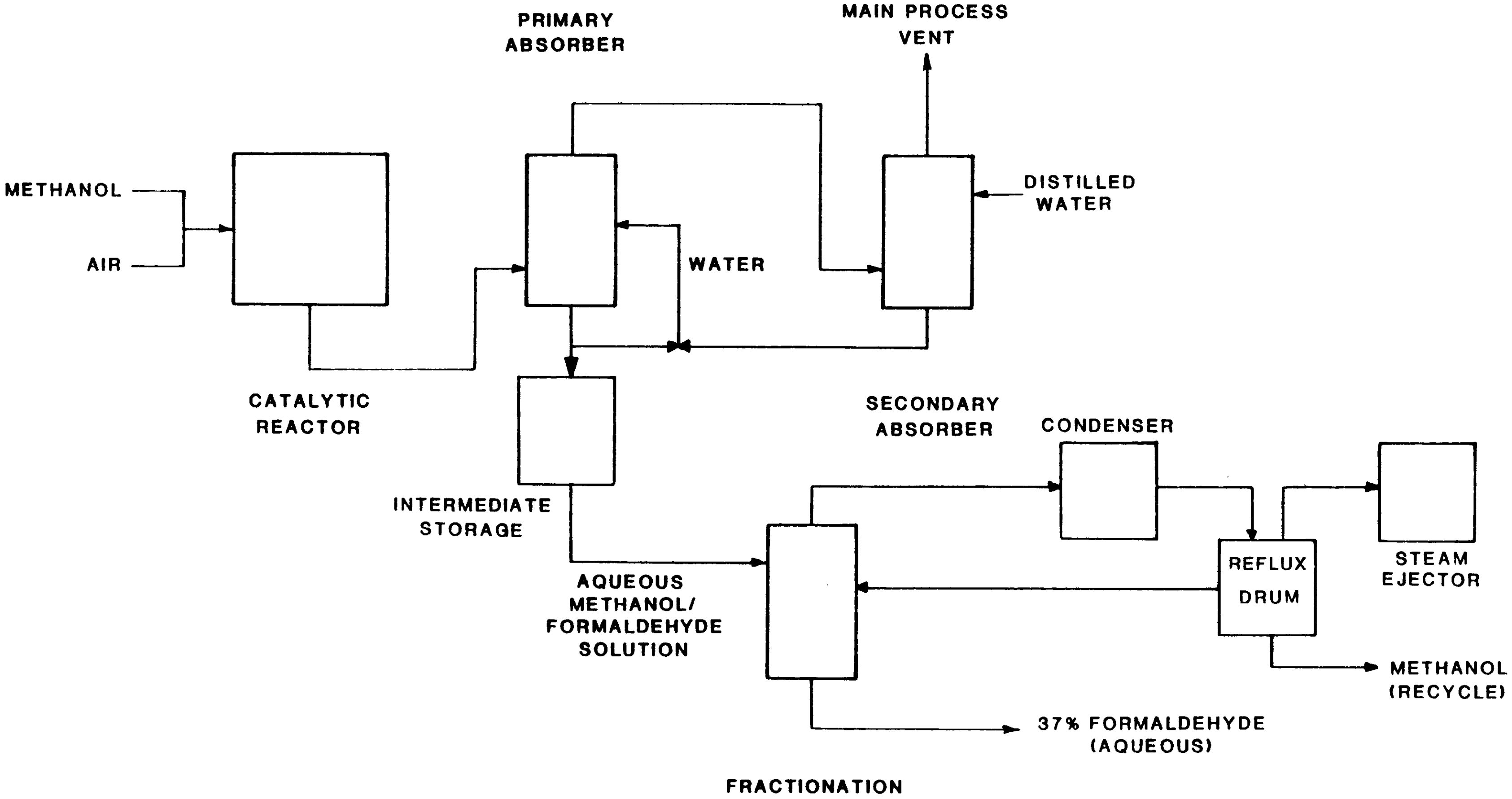
7.3.2.1 Process Description

The overall reaction for making formaldehyde from methanol with a silver catalyst is shown in the following chemical equation:

$$2\ CH_3OH + \tfrac{1}{2}\ O_2 \rightarrow 2\ CH_2O + H_2 + H_2O$$

Figure 7-8 is a simplified flow diagram of the silver catalyst process.

The feedstocks are prepared before they are introduced into the reactors. Air is washed with caustic to remove CO_2 and sulfur compounds and heated to about 80°C (180°F). The treated air and vaporized methanol are combined and sent to a battery of catalytic reactors. Some plants use a feed vs. effluent heat exchanger as the next step. Otherwise, effluent gases containing the formaldehyde go directly to the primary absorber for product recovery. The sorbent is an aqueous solution of formaldehyde and methanol, part of which is recycled back to the absorber. The other portion



Source: Reference 20

FIGURE 7-8. FLOW DIAGRAM FOR SILVER CATALYST PROCESS FOR FORMALDEHYDE PRODUCTION goes to an intermediate storage facility. Noncondensibles and uncondensed vapors are sent to a secondary absorber for further product recovery. Distilled water is used as a sorbent. The resulting solution of formaldehyde and methanol is used as makeup for the primary absorber. Noncondensibles and associated vapors (methanol, formaldehyde, methyl formate, CO) from the secondary absorber are vented overhead. The methanol and formaldehyde solution from the primary absorber is fractionated to yield 99 percent methanol and a 37 percent (weight) solution of formaldehyde containing less than 1 percent methanol. The formaldehyde product may undergo additional treatment to remove formic acid and to prevent polymerization during storage.

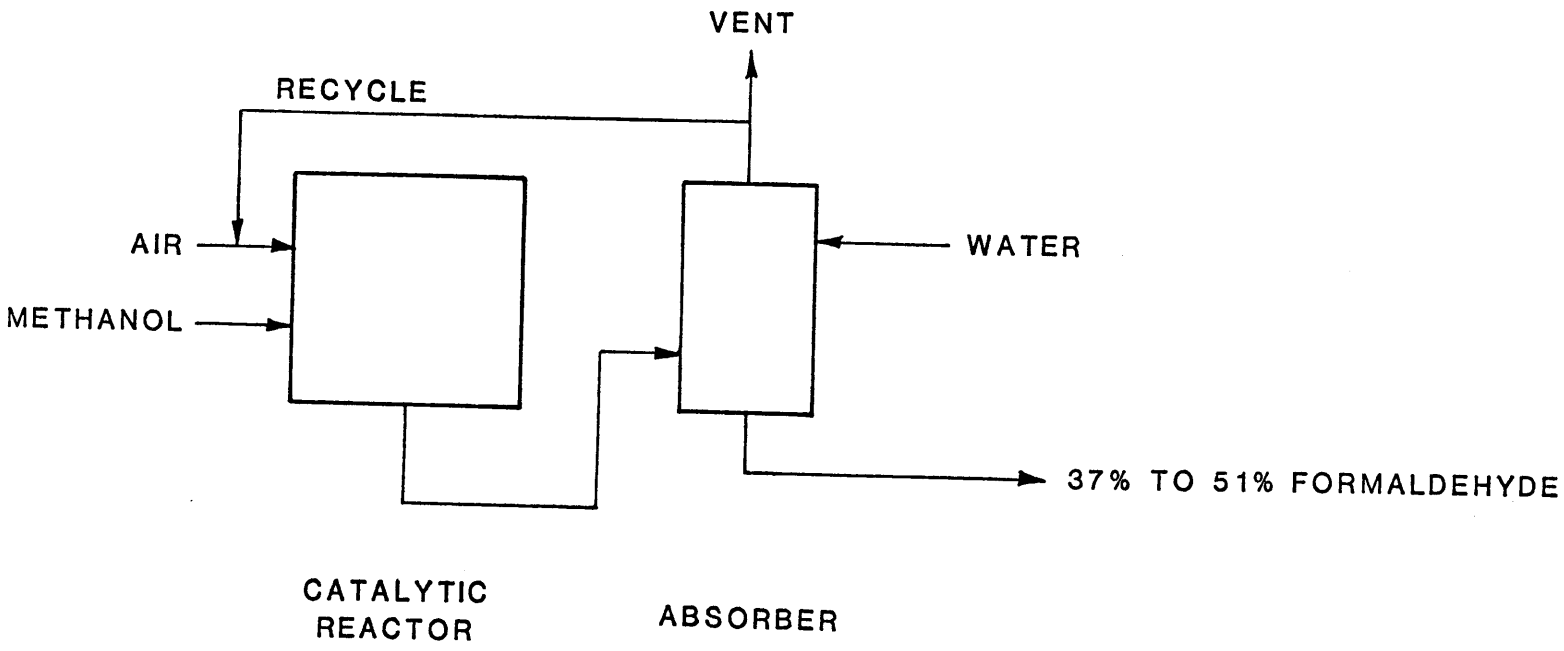
The reaction for making formaldehyde from methanol using the mixed metal oxide catalyst is shown in the following chemical equation.

$$CH_3OH + \frac{1}{2} O_2 \rightarrow CH_2O + H_2O$$

Methanol is mixed with air and recycled vent gas and heated to 105-177°C (220-350°F). The reaction takes place in the presence of a mixed oxide catalyst at temperatures between 343°C and 472°C (650°F and 880°F). The heat of reaction is removed by circulating coolant. A heat exchanger cools the effluent gases to 105°C (220°F) before they are quenched in the absorber. Water is used as a sorbent to form a 37-53 weight percent formaldehyde solution. Part of the noncondensibles are vented from the top of the absorber, and the remaining portion is recycled. Figure 7-9 is a simplified flow-sheet of the mixed oxide catalyst process.

7.3.2.2 Process Emission Sources and Factors

The main source of carbon monoxide emissions from both silver catalyst- and mixed oxide catalyst-based plants is the process absorber vent. In the



Source: Reference 18

FIGURE 7-9. FLOW DIAGRAM FOR MIXED OXIDE CATALYST PROCESS FOR FORMALDEHYDE PRODUCTION mixed oxide-based process, absorber vent gas stream composition is dependent primarily on gas recycle ratio. Other factors influencing absorber vent gas composition in this process are strengths of formaldehyde produced, catalyst formulation, catalyst age, and absorber operating temperature. The carbon momoxide emissions from the mixed oxide catalyst-process have been estimated at 0.16 kg/kg (0.16 lb/lb) 37 percent formaldehyde.[18] Table 7-6 presents a representative composition for the vent gas from the mixed oxide catalyst-process.[18]

The composition of the absorber vent gas stream from the silver catalyst process varies with catalyst age and activity. Uncontrolled emissions of carbon monoxide from this process have been estimated at 0.018 kg/kg (0.018 lb/lb) of 37 percent formaldehyde solution.[19] Controlled emissions from this process were calculated to be 10 percent of uncontrolled emissions: 0.002 kg/kg (0.002 lb/lb) of 37 percent formaldehyde solution. Table 7-7 presents a representative composition for the vent gas from the silver catalyst process.

TABLE 7-6

ABSORBER VENT GAS COMPOSITION IN THE MIXED OXIDE CATALYST PROCESS FOR FORMALDEHYDE

COMPONENT	VOLUME PERCENT
Formaldehyde	0.1
Methanol	0.1
Dimethyl Ether	0.1
Oxygen	7.7
Nitrogen	86.4
Carbon Dioxide	0.1
Carbon Monoxide	1.1
Water	4.4

Source: Reference 18

TABLE 7-7

ABSORBER VENT GAS COMPOSITION IN THE SILVER CATALYST PROCESS FOR FORMALDEHYDE

COMPONENT	VOLUME PERCENT
Formaldehyde	0.1
Methanol	0.3
Hydrogen	17.9
Carbon Dioxide	3.7
Carbon Monoxide	0.7
Oxygen	0.3
Nitrogen	74.2
Water	2.8

Source: Reference 19

EPA data indicate that carbon monoxide emissions from both formaldehyde processes were 64,900 metric tons (71,500 tons) in 1977.[2] Process-specific emissions data were not available.

7.3.2.3 Control Techniques

The majority of U.S. formaldehyde manufacturers do not currently control emissions of carbon monoxide from their process absorber vents. When surveyed in 1975, none of the producers using the mixed oxide process reportedly controlled CO emissions.[19] Four out of 35 plants using the silver catalyst process reportedly controlled CO emissions: two incinerated the waste gas without heat recovery and two used the waste gas as supplemental boiler fuel.[19] The following paragraphs describe both demonstrated and undemonstrated techniques for CO emission control.

Thermal Incinerator -- Although no performance data have been reported for thermal incinerators used on absorber vent gas streams, silver catalyst-based producers using this device have estimated carbon monoxide removal efficiency to be greater than 95 percent.[19] The thermal incinerators in use have operating parameters similar to those described in Chapter 6 but are specially designed to sustain combustion using gas with a heat content of as low as 2.24 megajoules/m^3 (60 Btu/ft^3).[19] Incinerator design details were considered proprietary. No thermal incinerator has been demonstrated in a mixed oxide plant, but the technique is also a feasible control method for this process.

The problems associated with applying thermal incineration to absorber vent gas streams are similar to those described in previous discussions of thermal incinerators. In addition, the relatively high hydrogen content of the gas in a silver oxide-based plant may pose some unique hazards.

Boiler Firebox -- Two plants producing formaldehyde via the silver catalyst process reportedly use absorber vent waste gas as supplemental boiler fuel.[19] Performance data from these plants were proprietary, but combustion of carbon monoxide should be essentially complete. A reduction in CO emissions of more than 95 percent should be achieved.[19]

It is not economically attractive to use vent gas from mixed oxide processes as supplemental boiler fuel because its energy content is very low [0.19 megajoules/m^3 (5 Btu/ft^3)].[18]

Catalytic Incinerator -- Catalytic incineration may be a feasible carbon monoxide control technique in formaldehyde manufacturing. Since no plants currently employ this technique, it is not known whether catalyst poisons are present in the vent gas. Estimated CO emissions reductions from a catalytic incinerator are comparable to those achieved by thermal incinerators. A more detailed description of catalytic incinerators is found in Chapter 6.

7.3.2.4 Cost of Controls

Annualized cost information for the above mentioned carbon monoxide controls is presented in detail in Chapter 6. Control costs for the formaldehyde industry may be determined as described in Section 7.3.1.4.

Model plant capacities, representative absorber vent gas flow rates, and average vent gas energy contents for the formaldehyde industry are shown in Table 7-8. The average flow rate for the absorber vent gas is 650 Nm^3 per metric ton of formaldehyde product (21,000 scf/ton) for the silver catalyst process and 1020 Nm^3 per metric ton (33,000 scf/ton) for the mixed catalyst process.[18,19] Using this information and the information and graphs in Chapter 6, annualized costs for the control techniques discussed in Section 7.3.2.3 can be estimated for an individual plant or for the formaldehyde industry as a whole.

7.3.2.5 Impact of Controls

Emissions Reduction -- As of 1975, carbon monoxide emission control systems were operative in only four formaldehyde plants.[19] Combined production from these plants, all of which use the silver catalyst process, represented 15 percent of total annual silver and mixed-catalyst based formaldehyde production.[18,19,20] Therefore, approximately 85 percent of the industry is uncontrolled with respect to carbon monoxide. The application of any of the control systems identified earlier for formaldehyde plants

TABLE 7-8

MODEL PLANT DATA FOR FORMALDEHYDE PRODUCTION WITH THE SILVER CATALYST AND MIXED OXIDE CATALYST PROCESSES OF FORMALDEHYDE PRODUCTION[a]

	SILVER CATALYST PROCESS	MIXED OXIDE CATALYST PROCESS
Model Plant Capacity	4.54×10^4 metric tons/yr (50,000 tons/yr)	4.54×10^4 metric tons/yr (50,000 tons/yr)
Representative Flow Rate Absorber Vent Gas	1.02 Nm^3/sec (2,170 scfm)	1.60 Nm^3/sec (3,390 scfm)
Energy Content of Gas	2.24 megajoules/m^3 (60 Btu/ft^3)	0.19 megajoules/m^3 (5 Btu/ft^3)

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[a] Data from References 18 and 19

on the uncontrolled production capacity could potentially reduce annual emissions of carbon monoxide by approximately 49,700 metric tons (54,700 tons), assuming an overall control efficiency of 90 percent. (See Section 7.3.2.2 for basis of estimate.)

Environment -- The environmental impact of the devices used to control carbon monoxide emissions from formaldehyde plants would be similar to that described in Section 7.3.1.5.

Energy Requirements -- Energy requirements of carbon monoxide control devices will vary with the type of device and the manufacturing process used. The low energy content of absorber vent gas from the mixed oxide catalyst process requires the use of substantial amounts of supplemental fuel for all feasible control devices. However, the energy content of vent gas from the silver catalyst process is high enough that specifically designed self-sustaining incineration devices may be used.

The amount of supplemental fuel needed for the control devices discussed in Section 7.3.2.3 is shown in Table 7-9. Calculations for the mixed oxide catalyst process were based on a plant producing 4.54 x 10^4 metric tons/yr (50,000 tons/yr) of a 37 percent formaldehyde solution, with a vent gas energy content of 0.19 megajoules/m^3 (5 Btu/ft^3).[18] Data for the silver catalyst process were calculated for a plant producing 4.54 x 10^4 metric tons/yr (50,000 tons/yr) with a vent gas energy content of 2.24 megajoules/m^3 (60 Btu/ft^3).[19]

7.3.3 Maleic Anhydride

Maleic anhydride is a white crystalline solid whose major use is in the formulation of polyester resins.[21] It is also an intermediate in the production of fumaric acid, agricultural pesticides, and alkyd resins.[21]

TABLE 7-9

ENERGY REQUIREMENTS FOR CO EMISSION CONTROLS IN FORMALDEHYDE PRODUCTION

CONTROL DEVICE	PROCESS	ENERGY REQUIRED[a]	ENERGY REQUIRED/UNIT WEIGHT OF PRODUCT
Thermal Incinerator			
Without heat recovery	Mixed Oxide	2.35 megajoules/sec (8 x 10^6 Btu/hr)	1.49 megajoules/kg (640 Btu/lb)
	Silver Catalyst	0.046 megajoules/sec (0.151 x 10^6 Btu/hr)	0.029 megajoules/kg (13 Btu/lb)
With 40 percent heat recovery	Mixed Oxide	1.47 megajoules/sec (5 x 10^6 Btu/hr)	0.93 megajoules/kg (400 Btu/lb)
Catalytic Incinerator	Mixed Oxide	1.47 megajoules/sec (5 x 10^6 Btu/hr)	0.93 megajoules/kg (400 Btu/lb)
	Silver Catalyst	0.037 megajoules/sec (0.125 x 10^6 Btu/hr)	0.023 megajoules/kg (10 Btu/lb)
Boiler Firebox	Silver Catalyst	(-) 1.19 megajoules/sec (-4 x 10^6 Btu/hr)	(-) 0.76 megajoules/kg (-320 Btu/lb)

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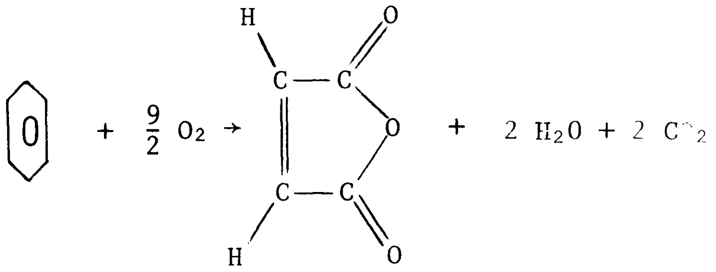
[a] Data from References 18 and 19 based on 8000 operating hours per year.

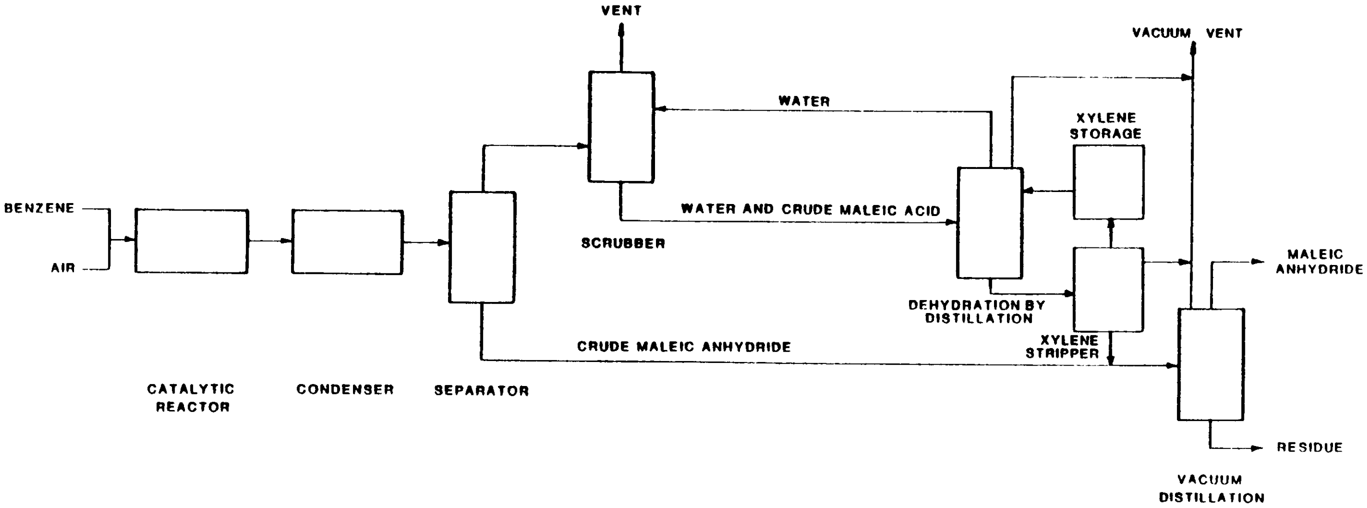
7.3.3.1 Process Description[20]

Maleic anhydride is produced by the catalytic oxidation of benzene. The reaction is shown in the following chemical equation.



Processing variations exist within the industry; however, the following process sequence is typical.[22] A mixture of benzene and air is introduced into a reactor containing vanadium pentoxide and molybdenum catalyst. Temperature control is achieved through circulating heat transfer fluid or molten salt. The reactor effluent is cooled before it passes through a partial condenser and separator. The overhead material is passed through an absorber for recovery of the anhydride as maleic acid. Maleic acid is generally dehydrated by azeotropic distillation with xylene. Some producers use thermal dehydration. The resulting anhydride is combined with maleic anhydride from the condenser. Purification is accomplished by vacuum distillation. The solid product is tableted or flaked before packaging or storage. The product may also be shipped in bulk liquid form. Figure 7-10 is a simplified flow sheet of the maleic anhydride process.

There are alternative processes using butane and butene feed. They are used by at least two U.S. producers and are used in several other countries. With the exception of raw material storage and some reactor modifications, the C_4-based system is about the same as the benzene-based



Source: Reference 20

FIGURE 7-10. FLOW DIAGRAM FOR PRODUCTION OF MALEIC ANHYDRIDE FROM BENZENE process. Small amounts of maleic anhydride are commercially produced as a by-product of phthalic anhydride production.[23]

7.3.3.2 Process Emission Sources and Factors

The only source from which carbon monoxide emissions have been reported in maleic anhydride production is the product recovery condenser vent gas.[22,24] The waste stream comes from the product recovery scrubber which is used to recover maleic acid from separator exit gas.

Uncontrolled emission estimates from the recovery condenser vent range from 0.44 to 0.87 kg CO/kg maleic anhydride (0.44-0.87 lb/lb.).[22] Controlled emission factors were calculated assuming 90 percent control efficiency: 0.087 kg/kg (0.087 lb/lb) maleic anhydride. Table 7-10 shows a representative composition of the vent gases containing carbon monoxide. Total mass carbon monoxide emissions from U.S. maleic anhydride production were estimated at 117,800 metric tons (129,900 tons) in 1977.[2]

TABLE 7-10

PRODUCT RECOVERY CONDENSER VENT GAS COMPOSITION
IN MALEIC ANHYDRIDE PRODUCTION

COMPONENT	VOLUME PERCENT
Oxygen	13.5
Nitrogen	81.9
Carbon dioxide	2.4
Carbon monoxide	2.0
Benzene	0.1

Source: Reference 24

7.3.3.3 Control Techniques

Control devices for carbon monoxide emissions are reportedly employed in three U.S. maleic anhydride plants.[24] The following paragraphs describe demonstrated CO control techniques as well as feasible, but undemonstrated CO control techniques.

Thermal Incinerators -- One U.S. maleic anhydride plant uses a thermal incinerator with 30 percent heat recovery to burn waste gas from the product recovery condenser vent.[22] The incinerator operates at 760°C (1400°F) and reportedly removes 95 percent of the carbon monoxide in the vent gas.[24] Approximately 25.4 megajoules/sec (86.7 x 10^6 Btu/hr) of supplementary fuel are required to maintain combustion in this device.[22]

Waste Heat Boiler -- At one U.S. maleic anhydride plant the vent gas is used as the primary air supply for a waste heat boiler.[22] Carbon monoxide removal efficiency for this device is reportedly greater than 95 percent.

Catalytic Incinerator -- A catalytic incinerator similar in design and operating parameters to the one described in Section 7.3.1.3 is used by one U.S. maleic anhydride producer to control emissions.[22] This device reportedly removes 80 to 85 percent of the CO present in the product recovery condenser vent stream. The problems and advantages of catalytic incinerators are discussed in Section 7.3.1.3.

7.3.3.4 Cost of Controls

Annualized cost information for the carbon monoxide control devices described above is presented in detail in Chapter 6. Control costs for the maleic anhydride industry may be determined as described in Section 7.3.1.4.

The reported flow rate for the condenser vent gas for a plant producing 23,900 metric tons per year (26,300 tons/yr) of maleic anhydride is 18 Nm^3/sec (38,000 scfm).[22] This amounts to a flow rate of approximately 21,700 Nm^3/metric ton (693,500 scf/ton) of product. A vent gas energy content of 0.56 megajoules/m^3 (15 Btu/scf) was estimated from reported material balance data.[23] Using this information and the information and graphs in Chapter 6, annualized costs for the control techniques discussed in Section 7.3.3.3 can be estimated for an individual plant or for the maleic anhydride industry as a whole.

7.3.3.5 Impact of Controls

Emissions Reduction -- As of 1977, only three U.S. maleic anhydride plants used carbon monoxide emission control systems.[22] Combined production from these plants represented 32 percent of the total annual production of maleic anhydride. Therefore, approximately 68 percent of the industry is uncontrolled with respect to carbon monoxide. Assuming application of demonstrated control technology with 90 percent CO removal efficiency, annual emissions could potentially be reduced by 72,100 metric tons (79,500 tons).

Environment -- The environmental impacts of carbon monoxide controls used in maleic anhydride plants are similar to those discussed in Section 7.3.1.5.

Energy Requirements -- The low energy content of the product recovery condenser vent gas from maleic anhydride plants requires the use of supplemental fuel in carbon monoxide emission control devices. The amount of energy required depends primarily on the type of device used.

Complete data regarding energy requirements of controls were not reported. However, data for the plant using a thermal incinerator with 30 percent heat recovery indicated that 25.4 megajoules/sec (86.7 x 10^6 Btu/hr) were necessary to maintain combustion temperatures at near-optimum levels.[24] This equivalent to 4.4 megajoules/kg (1900 Btu/lb) maleic anhydride.

No information was available on the energy requirements for waste heat boilers or catalytic incinerators used as control devices in maleic anhydride production. It is likely that energy requirements for waste heat boilers would be somewhat higher than those for thermal incinerators with heat recovery. Catalytic incinerators, however, should require substantially less supplemental energy because of their lower operating temperatures. However, if the plant can use the steam, a waste heat boiler is more energy efficient than a thermal or catalytic incineration system with heat recovery.

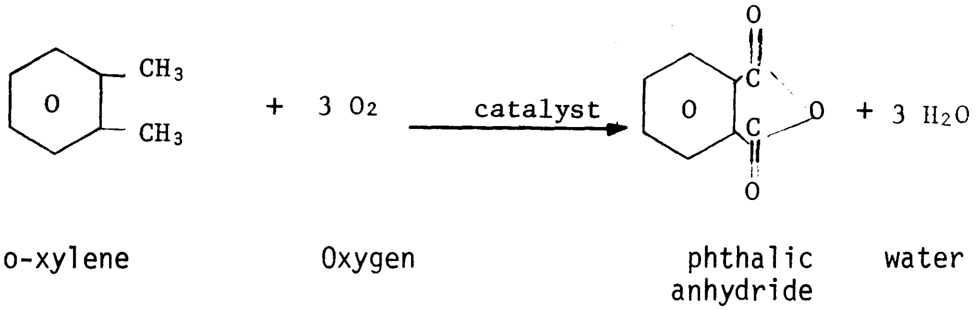
7.3.4 Phthalic Anhydride

Phthalic anhydride is produced by the vapor-phase oxidation of o-xylene or naphthalene. Approximately 67 percent of domestic-produced phthalic anhydride is produced from o-xylene; 33 percent is produced from naphthalene.[25] Since the o-xylene process is more economical (i.e., this process uses a cheaper raw material and yields slightly more product on a weight basis), future phthalic anhydride plants will probably be designed to use o-xylene as a feedstock.[26]

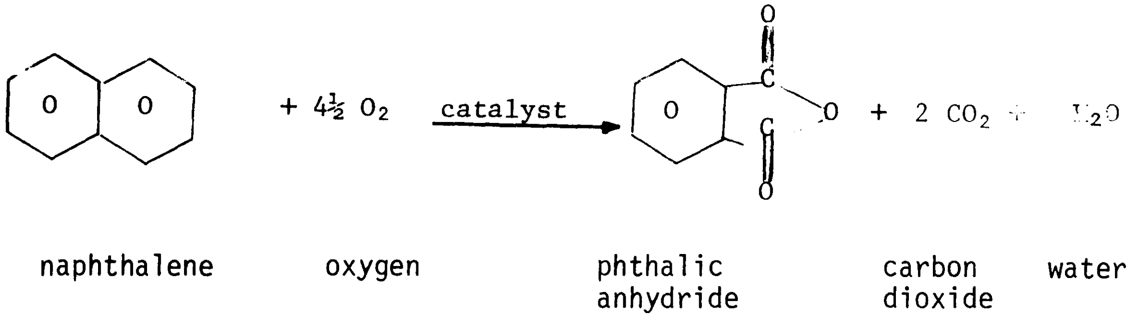
7.3.4.1 Process Description

There are basically two processes used for phthalic anhydride production in the United States. Processes using naphthalene as a feedstock use fluidized bed reactors; whereas, o-xylene-based plants use tubular fixed bed reactors. Except for the reactors and catalyst handling and recovery facilities used, the two processes are similar.

The following reaction describes the conversion of o-xylene to phthalic anhydride.



Naphthalene is converted to phthalic anhydride via the following reaction.

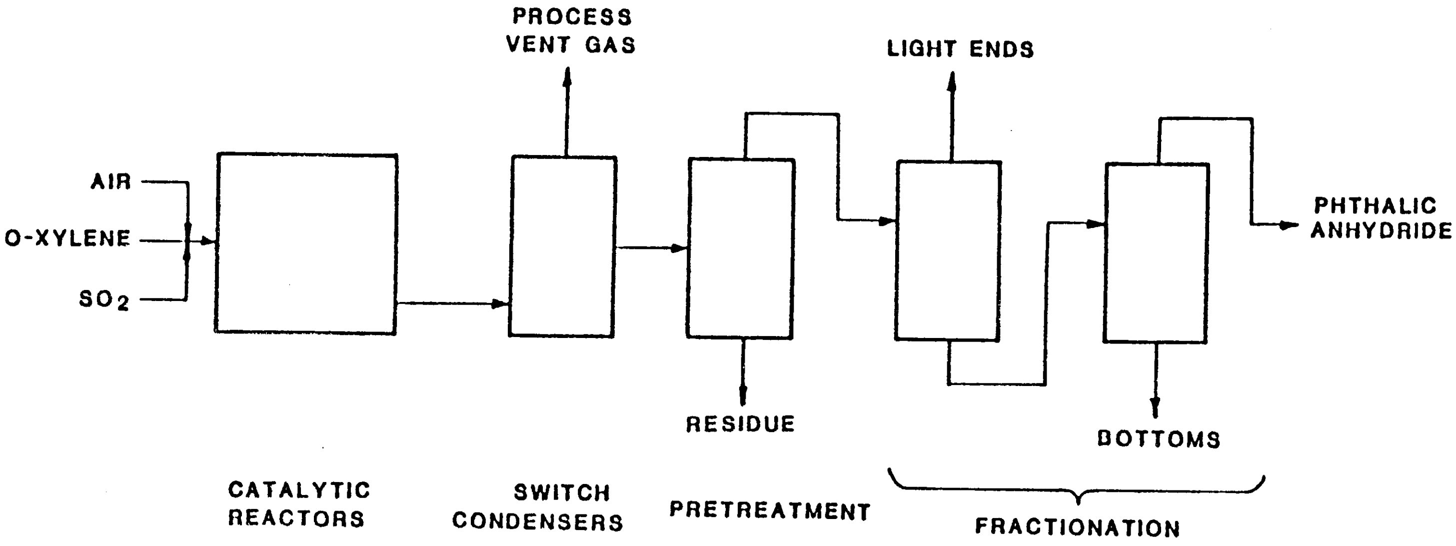


In both processes, a vanadium oxide catalyst is used. Small amounts of phthalic anhydride produced are oxidized to maleic anhydride, CO_2, and water.

Figure 7-11 is a flow diagram for an o-xylene based phthalic anhydride process. In both the o-xylene and naphthalene-based processes, filtered air is compressed to a range of 170 to 200 kilopascals (10-14 psig) and preheated.[26] Liquid o-xylene is mixed with reaction air and vaporized before it enters the fixed tubular bed reactors; whereas, liquid naphthalene is injected directly into a fluidized bed reactor and vaporized. Reactors in both processes operate at 340-385°C (650-725°F). A small amount of sulfur dioxide (SO_2) is added to the reactor feed to maintain catalyst activity.

Reactor effluent is used to generate low pressure steam in a waste heat boiler and then flows through a series of condensers (a parallel series of tubular condensers which are alternately heated and cooled). Crude phthalic anhydride is condensed as solid crystals on the condenser tube fins. It is then melted, removed from the condenser tubes, and sent to pretreatment. In this step, phthalic acid is dehydrated to the anhydride form, and impurities (water, maleic anhydride, and benzoic acid) are partially evaporated. The pretreated liquid stream is then sent to a vacuum distillation section where pure (99.8 percent) phthalic anhydride is obtained as a distillate. The pure product may be stored in a molten state or solidified to flakes and bagged for shipment.

All future phthalic anhydride industry growth is expected to be based on o-xylene feed. In 1977, only three of the ten phthalic anhydride plants in the U.S. were naphthalene-based.[25] Projected production capacity from naphthalene-based plants is expected to remain the same through 1985.[26]



Source: Reference 20

FIGURE 7-11. FLOW DIAGRAM FOR O-XYLENE BASED PHTHALIC ANHYDRIDE PROCESS

7.3.4.2 Process Emission Sources and Factors

The major source of carbon monoxide emissions from phthalic anhydride plants is the main process vent which comes from the switch condensers. Only 50 percent of U.S. plants control CO emissions from this point. Three plants reportedly use thermal incinerators and two others use a combination thermal incinerator/waste heat boiler to control emissions.[27]

Uncontrolled carbon monoxide emissions from the main process vent have been estimated at 150 kilograms of CO per metric ton of phthalic anhydride (300 lb/ton) in o-xylene-based plants, and 50 kilograms of CO per metric ton of phthalic anhydride (100 lb/ton) in naphthalene-based plants.[5] Incineration reportedly controls CO emissions to 0.125 g/kg (0.25 lb/ton) phthalic anhydride in o-xylene-based plants, and 0.05 g/kg (0.10 lb/ton) phthalic anhydride in plants where naphthalene is used as a feedstock.[25]

Recent EPA data indicated that carbon monoxide emissions from U.S. phthalic anhydride production were 50,900 metric tons (56,100 tons) in 1977.[2] Process-specific emissions data were not available.

7.3.4.3 Control Techniques

As was previously mentioned, only 50 percent of U.S. phthalic anhydride plants employ carbon monoxide control devices on their main process vent streams. The following paragraphs describe demonstrated CO control techniques as well as undemonstrated control techniques, for both o-xylene- and naphthalene-based processes.

Thermal Incinerator -- Three U.S. phthalic anhydride manufacturers use thermal incinerators to control carbon monoxide emissions from their main process vents. One plant is naphthalene-based and two are o-xylene based. Operating at 649°C (1200°F), the incinerator in one o-xylene-based plant reportedly removes greater than 90 percent of the CO in the switch condenser of gas.[25] Removal efficiencies of only 80-85 percent have been reported for a similar incinerator used in the naphthalene-based plant.[26,27]

Thermal incinerators may operate at higher temperatures than the ones currently in use (760-860°C [1400-1580°F]). Under these conditions, CO control efficiency could increase to 95 percent.[25]

Tables 7-11 and 7-12 list typical main process vent compositions for o-xylene and naphthalene-based plants, respectively. Because of the low energy content of the main process vent gas (0.075-0.112 megajoules/m^3 [2-3 Btu/ft^3]), supplemental fuel is needed to achieve complete combustion in a thermal incinerator.[25] Fuel requirements can be reduced if vent gas is preheated before being incinerated by heat exchange with the incinerator flue gas. However, preheating increases the danger of explosion if slugs of condensed phthalic anhydride are present in the vent gas.[25,26,27]

<u>Thermal Incinerator/Waste Heat Boiler</u> -- A thermal incinerator with a waste heat boiler is used to control carbon monoxide emissions from the main process vent in two U.S. phthalic anhydride plants.[27] This control technique reportedly achieves greater than 99 percent reduction in CO emissions.[27] The vent gas is not preheated prior to incineration, thereby avoiding the danger of explosion. Using an incinerator plus a waste heat boiler as a control technique requires more supplementary fuel than using an incinerator alone; however, as Table 7-13 shows, energy is recovered in the process stream produced.

TABLE 7-11

TYPICAL MAIN PROCESS VENT GAS COMPOSITION FROM O-XYLENE BASED PHTHALIC ANHYDRIDE PRODUCTION

COMPONENT	VOLUME PERCENT
Sulfur dioxide	<0.1
Carbon monoxide	0.6
Carbon dioxide	1.3
Nitrogen	76.9
Oxygen	15.7
Phthalic anhydride	<0.1
Maleic anhydride	<0.1
Benzoic acid	<0.1
Water	5.4

Source: Reference 27

TABLE 7-12

TYPICAL MAIN PROCESS VENT GAS COMPOSITION FROM NAPHTHALENE-BASED PHTHALIC ANHYDRIDE PRODUCTION

COMPONENT	VOLUME PERCENT
Phthalic anhydride	<0.1
Maleic anhydride	<0.1
Naphthoquinone	<0.1
Oxygen	12.2
Nitrogen	78.1
Carbon dioxide	5.1
Carbon monoxide	0.4
Water	4.1

Source: Reference 27

Catalytic Incinerator -- Catalytic incinerators have reportedly been used to control carbon monoxide emissions from other chemical processes. Emission reductions of 99 percent have been reported. It is not known whether any components which could poison the catalyst are present in the vent gases from phthalic anhydride plants. Since catalytic incinerators operate at lower temperatures than thermal incinerators (410-525°C [800-1000°F]), supplemental fuel requirements are somewhat less than requirements for an incinerator.

7.3.4.4 Cost of Controls

Annualized cost information for the above-mentioned carbon monoxide controls is presented in detail in Chapter 6. Control costs for the phthalic anhydride industry may be determined as described in Section 7.3.1.4.

A flow rate for the process vent gas from a model phthalic anhydride plant producing 5.9×10^4 metric tons/yr (1.3×10^8 lb/yr) is 56 Nm^3/sec (119,000 scfm).[26] An energy content of 0.112 megajoules/m^3 (3 Btu/ft^3) has been reported for vent gas containing carbon monoxide.[26] Using this information and the information and graphs in Chapter 6, annualized costs for the control techniques discussed in Section 7.3.4.3 can be estimated for an individual plant or for the phthalic anhydride industry as a whole.

7.3.4.5 Impact of Controls

Emissions Reduction -- As of 1977, carbon monoxide emission control systems were operating in five phthalic anhydride plants in the United States.[26] Four plants used o-xylene as a feedstock and one was naphthalene-based.[26]

Combined production from these plants represented 46 percent of the total annual production of phthalic anhydride. Therefore, approximately 54 percent of the industry is uncontrolled with respect to carbon monoxide. One source has estimated that if controls with at least 90 percent efficiency were applied industry-wide, carbon monoxide emissions could be reduced to less than 1,000 metric tons/yr (1,100 tons/yr).[25]

Environment -- Incinerators operating at the upper limits of their temperature range will produce more NO_x emissions than those operating at lower temperatures. It has been reported that emissions of NO_x will increase by approximately 15 percent when operating temperatures increase from 760-860°C (1400-1580°F).[10] NO_x emissions from catalytic incinerators should be negligible, since operating temperatures for this type of incinerator are considerably less than those of thermal incinerators.

If it becomes necessary to use fuel oil rather than natural gas as supplementary incinerator fuel, sulfur oxides (SO_x) emissions may increase. The amount of SO_x emitted will depend on the sulfur content of the fuel oil and the quantity of oil consumed.

Energy Requirements -- As was previously discussed, the low energy content of the main process vent gas from phthalic anhydride plants necessitates the use of supplementary fuel in the operation of any of the carbon monoxide emission control devices. The amount of energy required will depend primarily on the type of control device used.

The amount of supplemental fuel needed for several of the control devices is shown in Table 7-13. The calculations were based on a plant producing 5.9×10^4 metric tons/yr (1.30×10^8 lb/yr) phthalic anhydride with a process vent gas energy content of 0.112 megajoules/m^3 (3 Btu/ft^3).[26] Supplemental fuel data for catalytic incinerators were not available; however, because of their lower operating temperatures, substantially less energy would be required.

TABLE 7-13

ENERGY REQUIREMENTS FOR CO EMISSION CONTROLS IN PHTHALIC ANHYDRIDE PRODUCTION

CONTROL DEVICE	ENERGY REQUIRED[a]	ENERGY REQUIRED PER kg(lb) OF PHTHALIC ANHYDRIDE
Thermal incinerator without heat recovery	19.5 megajoules/sec (66 x 10^6 Btu/hr)	9.5 megajoules/kg (4.1 x 10^3 Btu/lb)
Thermal incinerator[b] + waste heat boiler	55.3 megajoules/sec (189 x 10^6 Btu/hr)	27.0 megajoules/kg (11.6 x 10^3 Btu/lb)

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[a] Data from Reference 25, based on 8000 operating hours per year.

[b] Steam production 12.2 kilograms per second (97,000 lb/hr) at 3.2 megapescals (450 PSIG) and 400°C (750°F)

7.4 IRON AND STEEL

Four methods used in making steel or smelting ferrous ore contribute heavily to the amount of carbon monoxide emitted from industrial processes. These four methods include steelmaking with basic oxygen furnaces (BOF's), ferroalloy and steel production using submerged arc and electric arc furnaces, respectively, ore dust agglomeration using sintering furnaces, and gray iron production from cupolas.

Table 7-14 lists mass carbon monoxide emissions from the processes described above. Estimated carbon monoxide emissions from these sources totaled 1.95 x 10^6 metric tons (2.15 x 10^6 tons) in 1977.[2] These emissions comprised about 23 percent of the CO emitted from industrial processes and about 11 percent of the total amount emitted from stationary sources.[2] The two major emitters of CO in the iron and steel industry are gray iron cupolas and sintering furnaces. Emissions from these sources represented about 84 percent of the total CO emissions from the iron and steel industry in 1977.[2]

TABLE 7-14

MASS EMISSION ESTIMATES FOR CARBON MONOXIDE FROM THE IRON AND STEEL INDUSTRY, 1977

SOURCE	CARBON MONOXIDE EMISSIONS Metric Tons	CARBON MONOXIDE EMISSIONS Tons
Sinter plants	624,700	688,600
Basic oxygen furnaces	99,200	109,400
Electric arc furnaces	205,700	226,800
Gray iron cupolas	1,020,800	1,125,200
TOTAL	1,950,400	2,150,000

Source: Reference 2

The following sections discuss the processes, emission factors, control techniques, and impact of cost of controls for each of the methods listed above. A discussion of blast furnace CO emissions, which are almost completely controlled, is also included.

7.4.1 Basic Oxygen Furnace

The basic oxygen furnace (BOF) process, also known as the Linz-Denowitz (L-D) process, is used to produce a major portion of steel in the U.S. The furnace is a pear-shaped, refractory-lined vessel, open at the top for charging while vertical and for pouring while tilted. This process is being increasingly used because of its high production rates, simplicity, and efficient operation.

7.4.1.1 Process Description

The feed metal used in the BOF process is typically 70 percent molten blast furnace iron and 30 percent scrap.[28] The furnace is also charged with fluxes, such as burnt lime, limestone, burnt dolomite, and fluorspar. Oxygen is blown into the charge through a water-cooled lance under pressure ranging from 1.1 to 1.3 megapascals (140 - 180 psi).[28] The process converts the hot metal into steel by oxidation of carbon, phosphorus, silicon, sulfur, and other impurities in the iron. This reaction occurs at approximately 2000°C (3600°F) and atmospheric pressure.[28] The steel is tapped into a ladle where desired alloying materials may be added. The molten steel is usually poured into ingot molds. The slag is tapped into slag pots and sent to the slag dump yard.

7.4.1.2 Process Emission Sources and Factors

Large amounts of carbon monoxide are generated by the oxidation reactions occurring in the BOF process. The exhaust gas at the surface of the molten liquid has a carbon monoxide content ranging from 87 to 95 percent.[29] Exhaust gas flow rates range from 570 to 940 Nm^3/sec (1.2×10^6 -1.99×10^6 ft^3/min).[28] Typical exit temperatures range from 1600°C - 1900°C (2900-3500°F).[28]

Uncontrolled carbon monoxide emissions from the BOF process are estimated to be 70 kg/metric ton (140 lb/ton) steel produced.[5] When control methods are applied, emissions are reduced to less than 1.5 kg carbon monoxide per metric ton steel (3 lb/ton).[5] Total mass CO emissions from U.S. basic oxygen furnaces were estimated to be 99,200 metric tons (109,400 tons) in 1977.[2]

7.4.1.3 Control Techniques

Most basic oxygen furnaces in the United States control carbon monoxide emissions by burning the waste gases with excess air in an open hood (Figure 7-12). A few U.S. facilities inhibit combustion with a retractable closed hood and flare the off-gas. Some foreign facilities collect it as fuel after cleaning (Figure 7-13).

In an open hood system, space is provided between the furnace and the hood to admit air for the combustion of carbon monoxide. Closed hood systems use retractable skirts or other methods to limit the quantity of air entering the hood. Hoods are water cooled, using either hot or cold water or steam. When either type of hood is used, reductions in carbon monoxide emissions exceed 98 percent.[5] During charging and pouring, the furnace and hood are disengaged. However, most of the CO is emitted during blowing.

7.4.1.4 Cost of Controls

The hooding design affects the cost of the total system. Open hoods draw in air on a relatively uncontrolled basis, thus increasing the capital and operating costs of the particulate collection equipment.[30]

Closed hood systems are more difficult to fabricate and maintain. In addition, provision must be made for gas accumulation or flaring. However, particulate collection costs less for closed hood systems. Economics of the

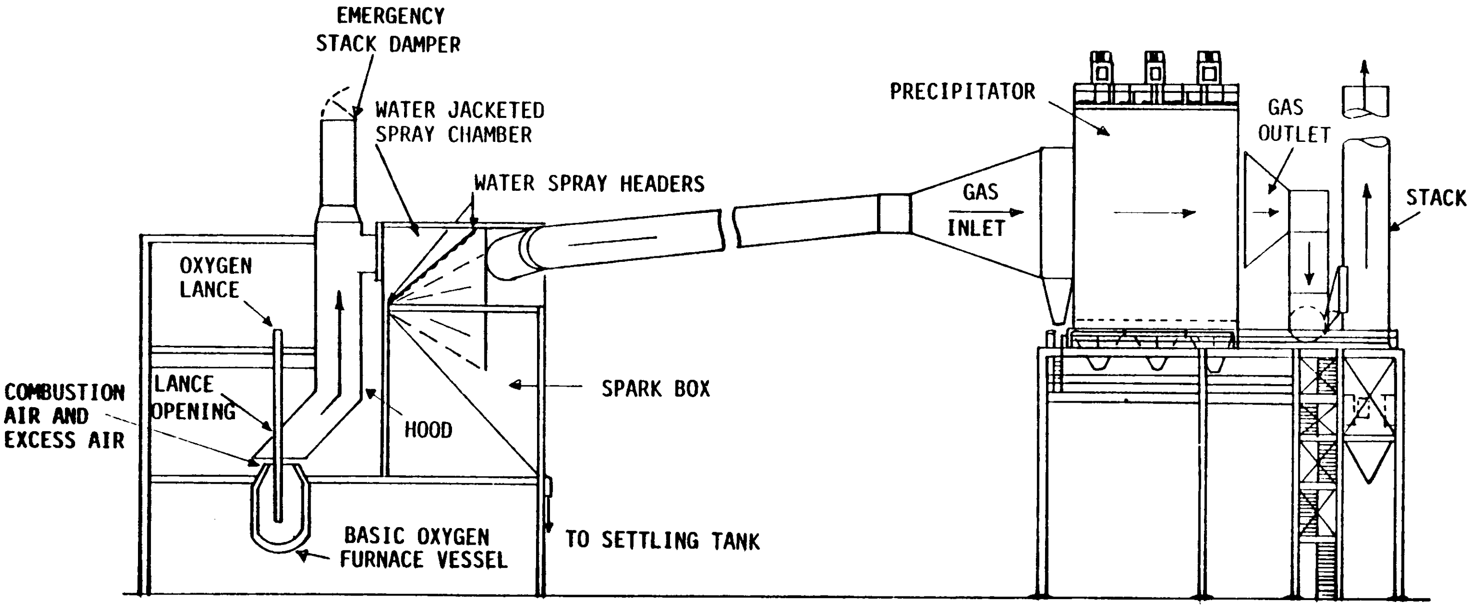


FIGURE 7-12. BASIC OXYGEN FURNACE WITH OPEN HOOD AND GAS-CLEANING AND STORAGE SYSTEM

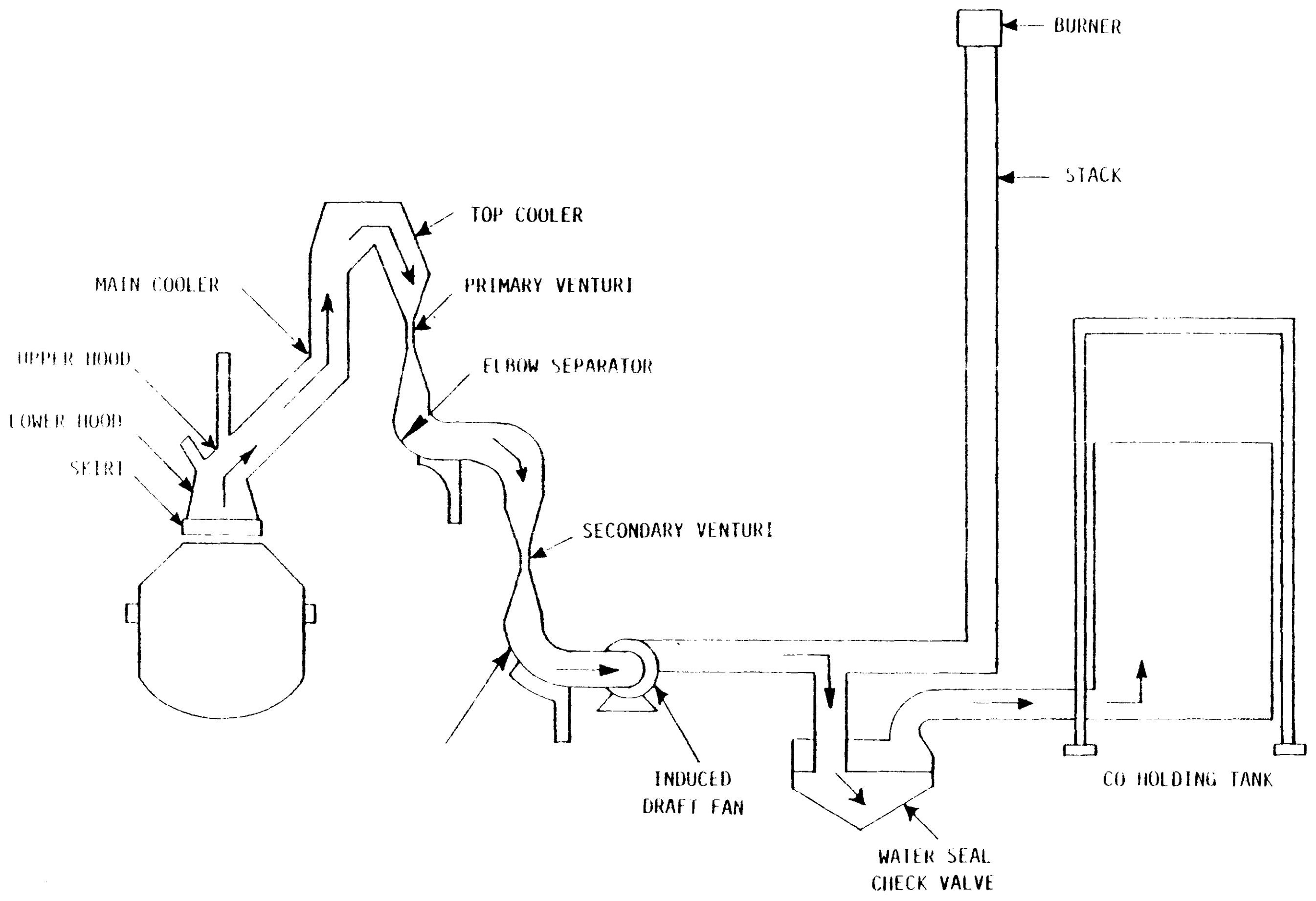


FIGURE 7-13. BASIC OXYGEN FURNACE WITH CLOSED HOOD AND GAS-CLEANING SYSTEM

entire process and particulate emission regulations will determine the more appropriate method.

7.4.1.5 Impact of Controls

Emissions Reduction -- Open hood combustion reduces CO in the furnace exhaust gas to less than 1.5 kg/metric ton (3 lb/ton).[2] If closed hood systems are used, 98 percent of the carbon monoxide produced can be recovered and used as waste heat boiler fuel.[30]

Environment -- The industry-wide acceptance of burning waste gas in steel production via the BOF process has significantly reduced CO emissions. Nitrogen oxide (NO_x) emissions during combustion of the waste gas under the open hood are about 180 to 500 micrograms of NO_x per metric ton (0.36 to 1.0 pound per ton) of steel produced.[30] There would probably be lower NO_x emissions from closed hood collection since no incineration occurs. However, there would be NO_x emissions from flaring or from burning the gases in a boiler. Particulate emissions are also greater with open hoods than with closed hoods.

Energy Requirements -- The energy content of BOF exhaust gas is high enough so that no supplemental fuel is necessary to maintain combustion in an open hood or flare. When the carbon monoxide is burned, about 470 kilojoules/kilogram (400,000 Btu/ton) are produced.[30] If closed hoods are used and the exhaust gas is cleaned and recovered, it may be used to produce steam for other process units.

7.4.2 Blast Furnace

Blast furnaces are vertical, refractory-lined shaft furnaces up to 36.6 meters (120 feet) tall and 8.5 meters (28 feet) in diamter. They reduce iron ore to molten pig iron, most of which goes directly to steel furnaces.

7.4.2.1 Process Description

Blast furnaces are so called because air preheated from 760°C to 1150°C (1400°F to 2100°F) is blown into the furnace near the bottom to burn the coke.[28] Iron ore, sinter, iron or steel scrap, coke, and flux (limestone) are charged into the top of the furnace.[28] In 1973, an average of 1.5 metric tons (1.7 tons) of charge was consumed per ton of pig iron produced.[28] Blast furnaces operate at pressure ranging from 170 to 580 kilopascals (10 to 70 psi).[28] When temperatures inside the furnace exceed 1450°C (2640°F), the combustion product, CO_2, reacts as follows to produce carbon monoxide:

$$C + CO_2 \rightarrow 2CO$$

The carbon monoxide is necessary to reduce the iron oxides present in the ores to elemental iron. As the metals descend, they are heated by the reducing gases.

As the elemental iron moves toward the furnace fusion zone, it becomes molten and collects in the hearth (See Figure 7-14). The limestone flux reacts with impurities in the ore and coke and forms a molten layer of slag on the pool of iron. Periodically, the molten iron and slag are tapped from the blast furnace. The molten pig metal typically contains 4.1 percent carbon, 0.9 percent silicon, 0.026 percent sulfur, 0.30 percent phosphorus and 0.35 percent manganese.[31]

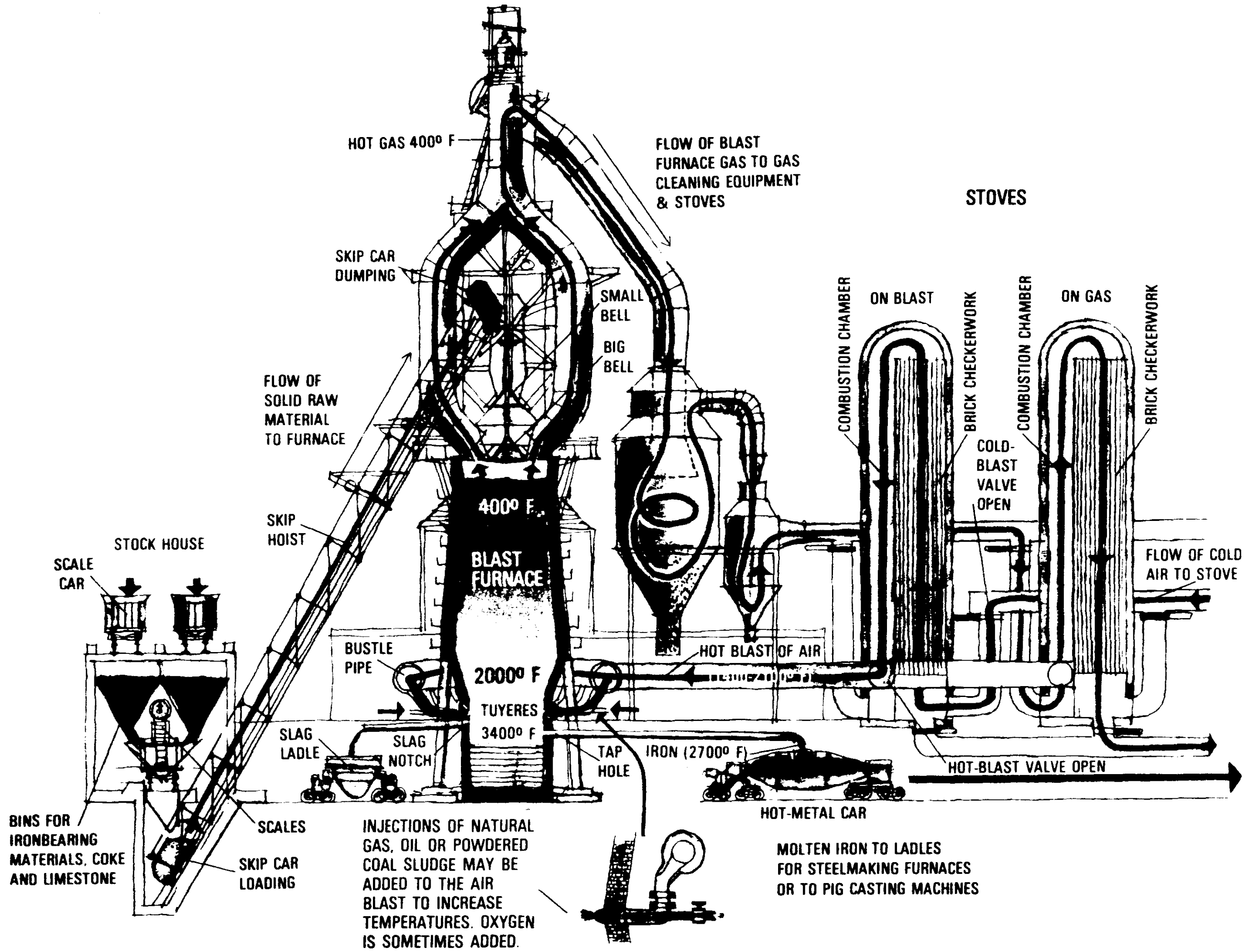
7.4.2.2 Process Emission Sources and Factors

Exhaust gases leave the blast furnace at temperatures of 180°C to 280°C (350°F to 540°F). The gas flow rate increases linearly with the coke feed rate. One source estimated that 2.2 to 3.5 kilograms of exhaust gas are generated per kilogram of pig iron produced (2.2 to 3.5 lb/lb).[30] As much as 30 percent of the exhaust gas volume may be carbon monoxide.[32] Uncontrolled carbon monoxide emissions in furnace exhaust gas average 875 kilograms of CO per metric ton of pig iron (1750 pounds per ton).[5] However, relatively little carbon monoxide is vented to the atmosphere, since 99.9 percent of the CO generated is normally collected, cleaned, and used as process fuel.[5]

Occasionally, conditions within the furnace such as "slips" (sudden movements of the charge into the furnace) generate high pressures which open the furnace's pressure relief valves. Uncontrolled amounts of carbon monoxide escape through the relief valves and the furnace charging enclosure during "slips". No emissions estimates for CO have been reported for "slip" conditions.

7.4.2.3 Control Techniques

The technique for controlling carbon monoxide emissions from blast furnaces is part of the system used to control particulate emissions. A typical system is shown in Figure 7-14. Initially, exhaust gas passes through a settling chamber or a dry cyclone, where about 60 percent of the dust is removed. Next, the gas undergoes a one- or two-stage cleaning operation, in which the remaining particles are removed by a wet scrubber



Source: Reference 33

FIGURE FIGURE 7-14. SCHEMATIC DIAGRAM OF A BLAST FURNACE or electrostatic precipitator. The cleaned gas is then ready to be used as low energy process fuel.

7.4.2.4 Cost of Controls

There are no additional costs for controlling carbon monoxide emissions from blast furnaces. The exhaust gas is used as a fuel.

7.4.2.5 Impact of Controls

Emissions Reductions -- As was previously discussed, carbon monoxide emission control from blast furnaces is relatively complete throughout the industry. Any remaining CO emissions result from escaping gas during high pressure "slips." Improved charging techniques and operating practices which closely adhere to furnace design specifications have significantly reduced the number of "slips."

Environment -- Since blast furnace gas is used as a fuel, nearly all the carbon monoxide produced is oxidized to CO_2 before it reaches the atmosphere.[32]

Energy Requirements -- The energy content of the blast furnace exhaust gas is approximately 3.73 megajoules/m^3 (100 Btu/ft^3).[32] It is therefore economical to use the exhaust gas for process fuel. About 30 percent of the cleaned gas is typically used to fire the stoves in which blast furnace air is preheated.[32] The remaining gas is used as fuel for other in-plant purposes.[32]

7.4.3 Submerged Electric Arc Furnace

Submerged arc furnaces are used in the production of ferroalloys. The basic raw materials used are metallic ores, limestone, and a reducing agent (coke or low-volatile coal).[34] The exact composition of the charge depends on the product desired. Iron, silicon, manganese, chromium, calcium, and zirconium are some of the metals which may be alloyed or reacted in the furnace.

7.4.3.1 Process Description

Submerged arc furnaces of the same general design are used throughout the ferroalloy industry. The cylindrical steel furnace shell has a flat bottom and is supported on an open foundation that permits air cooling and heat dissipation. The furnace shell's interior walls are lined with refractory brick. One or more tapholes for removing slag and metal exist at hearth level.[34]

Graphite electrodes in electric submerged arc furnaces extend three to five feet into the charge. The coke in the charge reacts with the metal oxides and reduces the ores to base metal. Maximum furnace temperature is 1570°C (2860°F). Most furnaces operate at atmospheric pressure.[35]

Continuous power is supplied to the furnace electrodes, whose depth is varied during the process to maintain a uniform electrical load throughout the charge. Oxidation begins to occur when molten metal begins to form and continues until the entire charge is in solution. At the end of the process, the electrodes are raised, and the molten product is tapped into ladles and further treated, as desired. Slag removal may occur prior to or during tapping, or at the end of the tap.

7.4.3.2 Process Emission Sources and Factors

The composition of exhaust gas from submerged arc furnaces varies with hooding practices, slagging practices, process stage, and whether or not oxygen lancing is used. Major constituents of the exhaust gas include carbon monoxide, carbon dioxide, oxygen and nitrogen. Fluorides and other vaporized metallic compounds may also be present, depending on the type of ferroalloy being produced.[35]

Emission points in electric submerged-arc furnaces include the electrode ports in the furnace roof, the tapping spout, the slagging door, and the open furnace top during charging. Uncontrolled carbon monoxide emissions from direct electric arc furnaces have been estimated at 9 kilograms CO per metric ton of ferroalloy produced (18 lb/ton).[5] Exhaust gas from a number of facilities tested contained between 60 and 95 percent CO.[36] Carbon monoxide concentrations of 80 to 90 percent are common during short periods of each cycle.[35] Typical gas volumes range from 50 to 190 normal cubic meters per second (100,000-400,000 scf/min).[35]

Recent EPA emissions estimates indicate that 205,700 metric tons (226,800 tons) of carbon monoxide were produced from both direct- and submerged-arc furnaces.[2] No process-specific data were available.

7.4.3.3 Control Techniques

A number of techniques exist for controlling carbon monoxide emissions from electric submerged-arc furnaces. The following paragraphs describe these techniques.

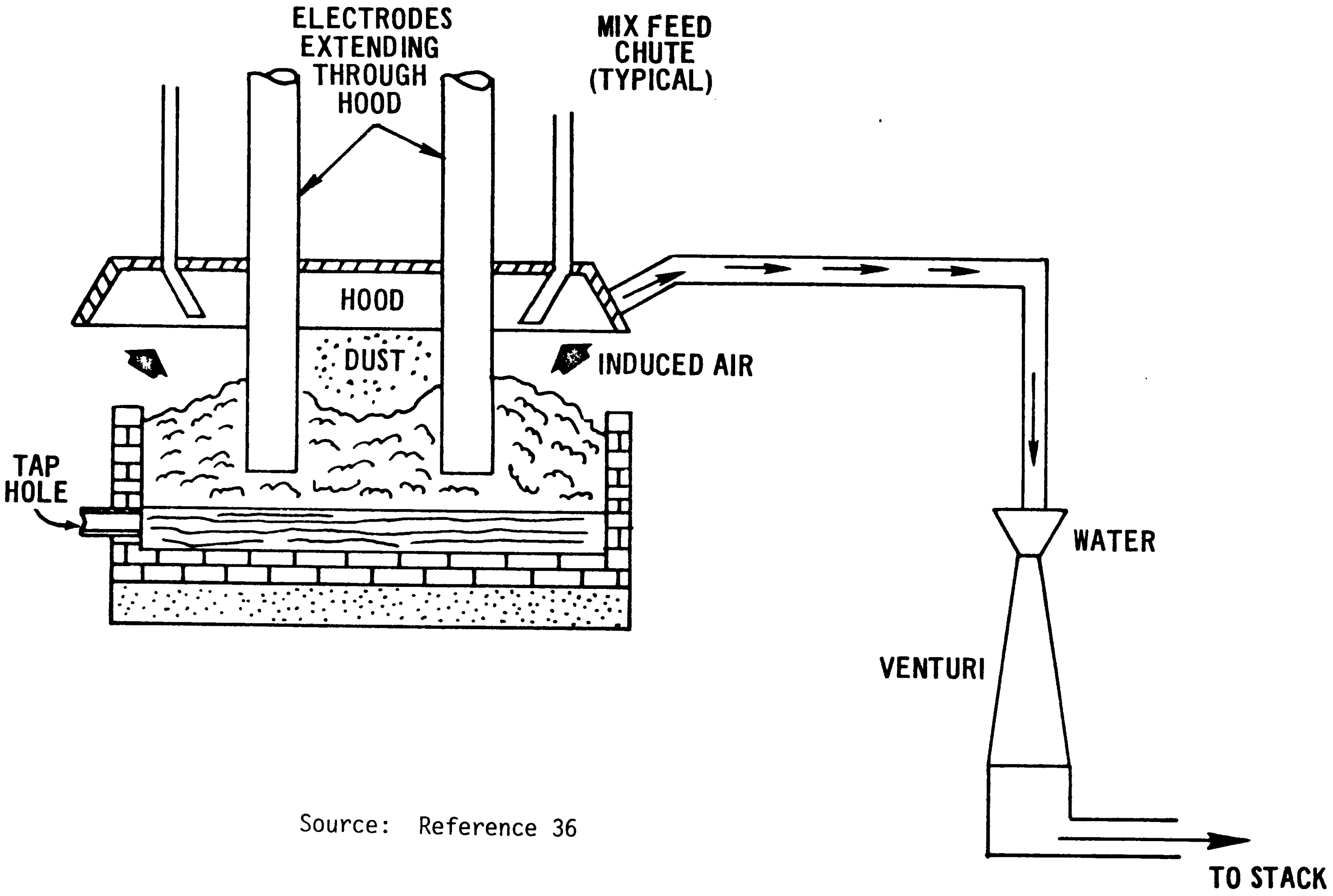
Carbon monoxide reduction in electric arc furnaces is achieved by inducing air into the exhaust hood. In a few cases the gases are collected, then burned. There are three hood configurations for submerged arc furnaces: the open, the semi-enclosed, and the sealed furnace. The type of hooding system used has an important effect on CO emission reduction. A few installations also supplement their hoods by shrouding or enclosing the furnace area to capture the pollutants emitted during charging and tapping operations.[34] The CO emissions which escape the hoods are emitted in the exhaust from the furnace building.

The open electric submerged arc furnace configuration (Figure 7-15) employs a water-cooled canopy hood 2 to 2.7 meters (6 to 8 feet) above the furnace rim. Air surrounding the furnace burns the CO as it combines with the hot gases under the hood, diluting them by as much as 50 to 1.[34]

In the semi-enclosed electric submerged arc furnace (Figure 7-16) emissions are drawn from beneath a water-cooled cover that completely seals the furnace except for annular spaces around the three electrodes through which the raw materials are charged. Because very little air enters the semi-enclosed furnace, gases from the furnace are concentrated in carbon monoxide and can be used as fuel or flared after cleaning.[35]

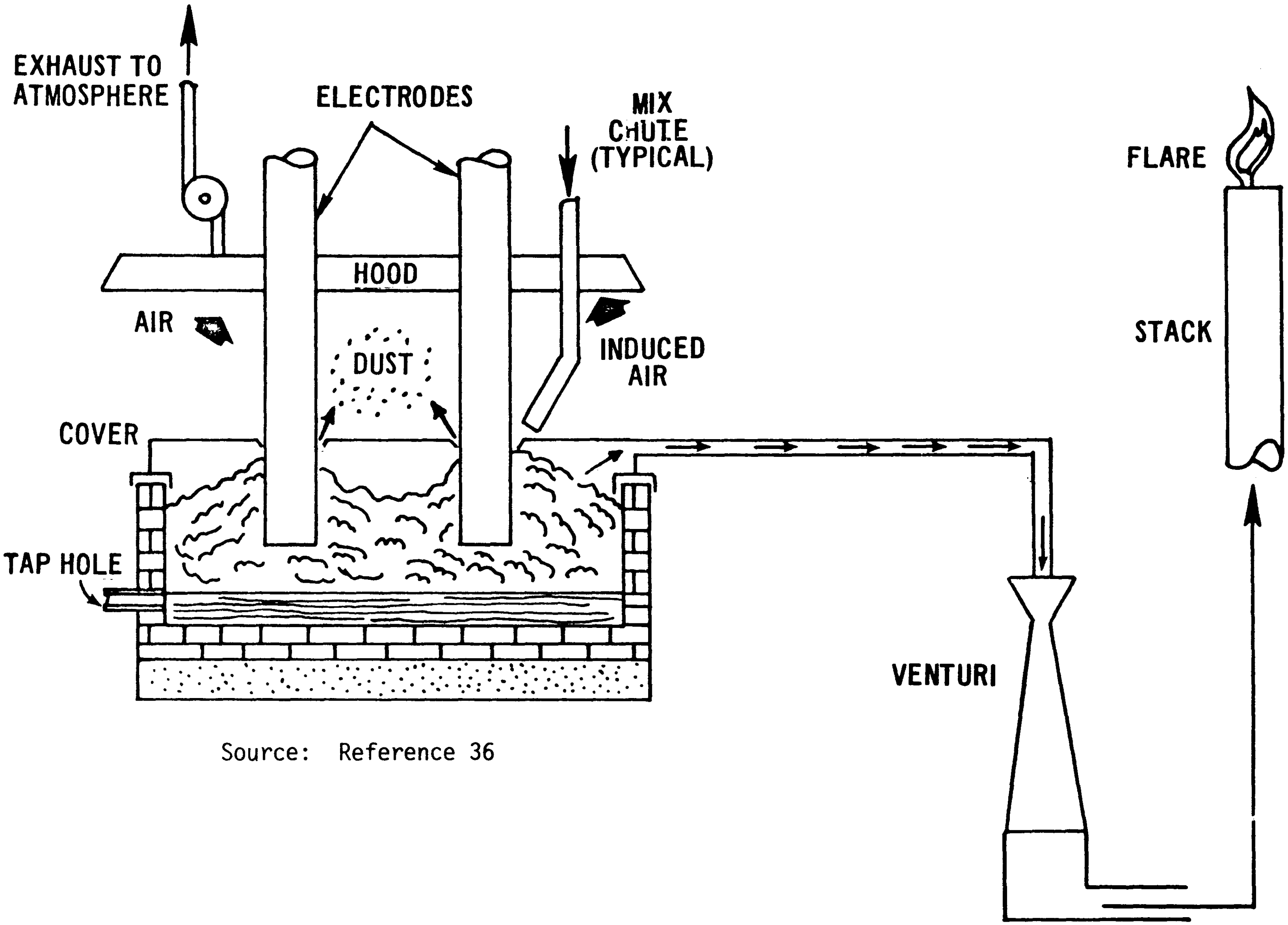
Emissions leaking through the charging holes around the electrodes can be minimized by maintaining a negative pressure within the furnace. This involves using a fan to draw gases into the dust-cleaning device. The induced air also oxidizes some of the carbon monoxide, reducing its fuel value and raising the gas exit temperature.[35]

Another way of reducing emissions from sealed furnaces (Figure 7-17) is by packing seals around the electrodes and charging chutes. In this case, the fuel value of the exhaust gas is preserved because a slight positive operating pressure is maintained, preventing leakage of air into the furnace. Gases withdrawn from sealed furnaces may be as little as 2 to 5



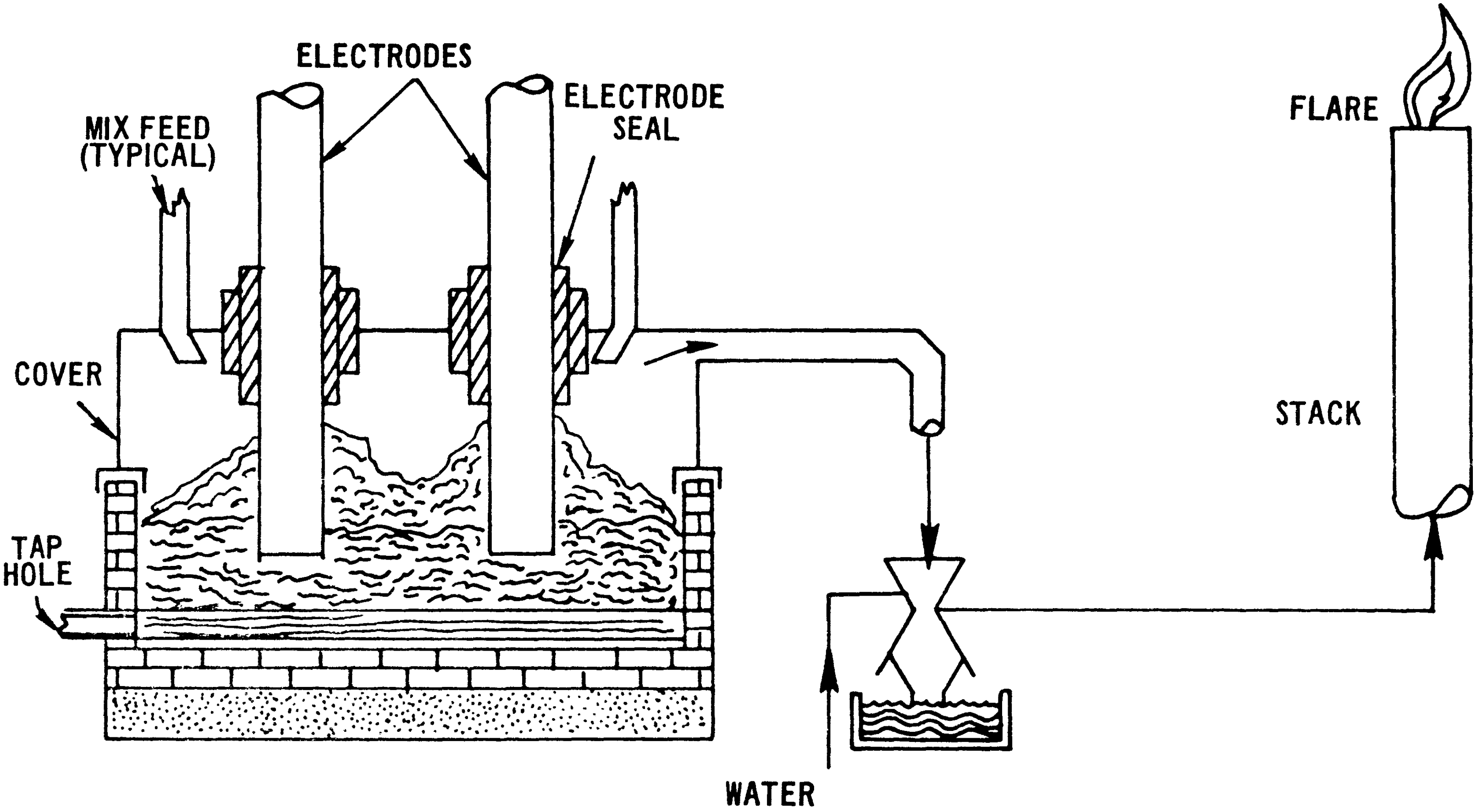
Source: Reference 36

FIGURE 7-15. OPEN FURNACE CONTROLLED BY A VENTURI SCRUBBER



Source: Reference 36

FIGURE 7-16. SEMI-ENCLOSED FURNACE CONTROLLED BY A VENTURI SCRUBBER



Source: Reference 36

FIGURE 7-17. SEALED FURNACE CONTROLLED BY VENTURI SCRUBBER percent of the volume handled in open furnaces.[35] Gases from sealed furnaces are flared or are used for fuel.

Production of silicon metal or alloys containing over 75 percent silicon are limited to open furnaces with canopy hoods because the techniques which need to be used to prevent crusting and bridging of the charge and "blows" (jets of extremely hot gas) cannot be employed with semi-enclosed and sealed furnaces.[35]

Some of the specific types of hood systems used are as follows: The roof hood or the "plenum roof" (Figure 7-18) covers the furnace roof with openings for the electrodes and overhangs above the charge door and tapping spout.[35] The direct shell evacuation or "fourth hole" system (Figure 7-19) (so-called due to the three electrode holes already in the furnace roof) ducts the exhaust gases from beneath the furnace roof. A gap in the duct elbow aspirates air to burn the waste gases. This system is totally ineffective when the roof ring is swung aside for charging and during tapping. The advantages are similar to those for sealed ferroalloy furnaces (i.e., less exhaust gas).[35]

The side draft hood (Figure 7-19) mounted on the furnace roof draws a high velocity indraft of 31 to 190 Nm^3/metric ton (1000 to 6000 ft^3/ton) to capture emissions around the electrodes. No extra air is needed to burn the escaping carbon monoxide as the hood only partially surrounds the electrodes, hence the name side-draft. However, carbon monoxide destruction may not be as complete as achieved in the direct shell evacuation system during meltdown since the side-draft hood draws in a large amount of cool air, possibly lowering the temperature of the exhaust draft below the ignition point.[35]

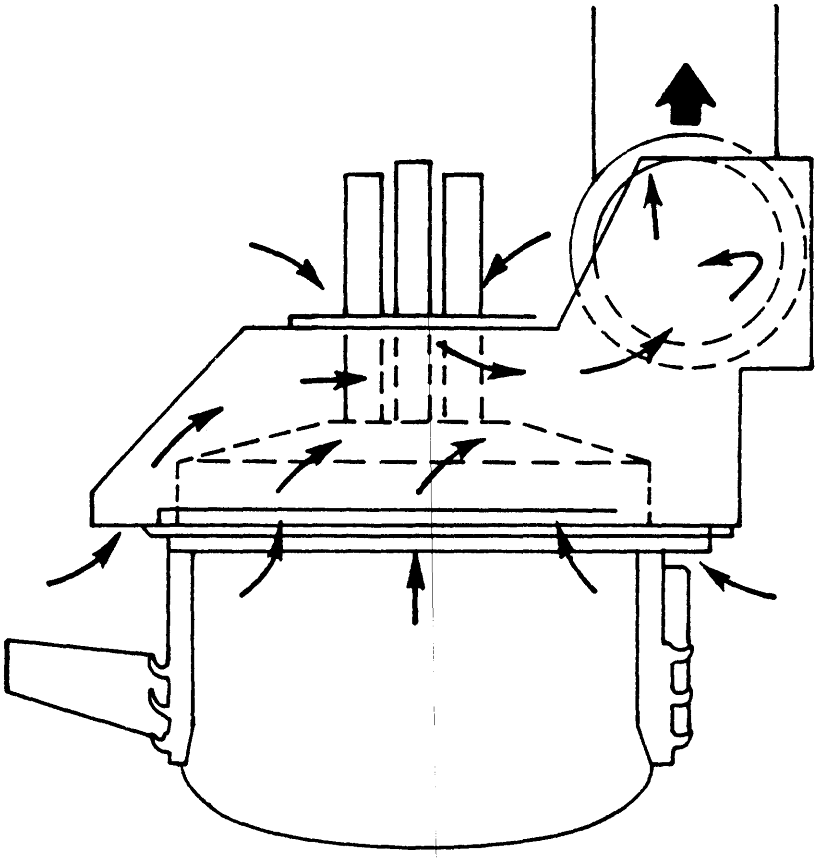
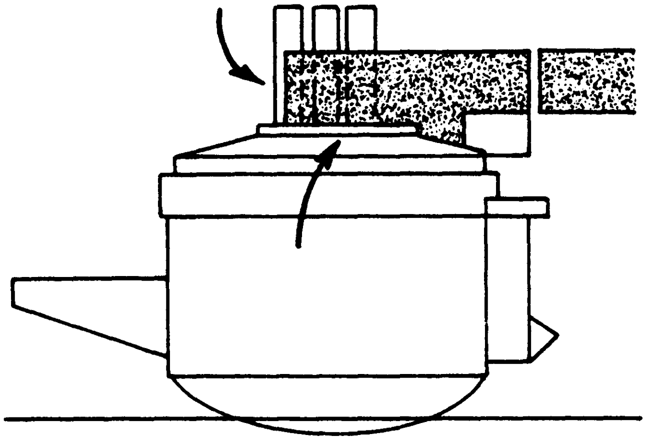
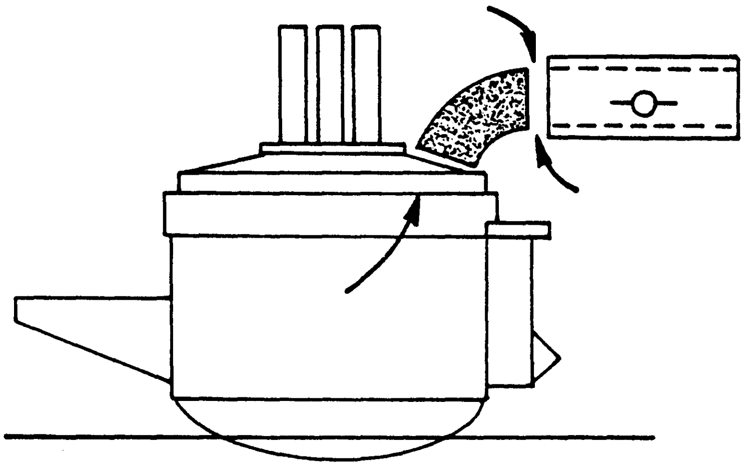


FIGURE 7-18. ROOF HOOD



SIDE DRAFT



DIRECT EVACUATION-FOURTH HOLE

FIGURE 7-19. SIDE DRAFT AND DIRECT EVACUATION HOODS

7.4.3.4 Cost of Controls

The problem of cost development for carbon monoxide emission control is similar to that described in Sections 7.4.1.4 and 7.4.2.4. Since the ventilation and transport systems used in CO control are also part of the particulate control system, it is difficult to separate costs for CO control alone.

7.4.3.5 Impact of Controls

Emissions Reduction -- When applied, the emission control techniques described in Section 7.4.3.3 are effective methods of reducing carbon monoxide emissions from electric submerged arc furnaces. If controls were employed on all submerged arc furnaces, emissions reduction of more than 90 percent should be achieved.[35]

Environment -- No nitrogen oxides (NO_x) are formed during the carbon reduction of oxidic ores.[35] Any NO_x formed as a result of carbon monoxide emission control would be due to fixation of atmospheric nitrogen. If closed systems are used and the CO-rich exhaust gas is recovered and used as process fuel, NO_x emissions should not be any greater than if natural gas were used as fuel.

Energy Requirements -- If submerged-arc exhaust gas is burned in an open hood, no supplementary fuel (other than air) is necessary to maintain combustion. Neither is supplementary fuel needed if the gas is flared.

Because the exhaust gas is 60-90 percent carbon monoxide, it can be used as a process fuel.[35] The energy content of the gas was calculated to be approximately 10 megajoules/m^3 (270 Btu/ft^3).

7.4.4 Direct Electric Arc Furnace

Direct electric arc furnaces are used in the production of high-alloy steels (e.g., carbon and stainless steels) and considerable amounts of mild steel.[28] Steel production in direct arc furnaces has steadily increased, due to the increased availability of steel scrap.[37]

7.4.4.1 Process Description

Typical electric arc furnaces range in diameter from about 1 meter (3 feet) up to 4 meters (12 feet) with holding capacities of 230 kilograms (500 pounds) to 23 metric tons (25 tons), and production rates from 115 kilograms (250 pounds) to 10.9 metric tons (12 tons) per hour.[38] Modern furnaces up to 5.2 meters (17 feet) in diameter may hold 59 metric tons (65 tons) and have production rates of over 18 metric tons (20 tons) per hour.[38]

Electric arc furnaces are basically refractory-lined crucibles with a steel shell. In almost all applications, the furnace roof can be swung aside for top charging. The roof is also refractory-lined, with ports allowing the insertion of three graphite electrodes into the furnace just above the surface of the charged metals. Maximum furnace temperature is 1570°C (2860°F). Most furnaces operate at atmospheric pressure.[35]

The charge for iron or steelmaking usually consists of steel scrap, cast iron scrap, pig iron, alloying elements, and flux. Preheating the steel scrap is not a common practice when direct electric arc functions are used. Addition of oxygen (oxygen lancing) during the melting process reduces energy consumption and increases production rates.

The oxidation process in direct arc furnaces is similar to that described for submerged arc furnaces (Section 7.4.3.1). Similar tapping and slagging procedures are employed in both processes.

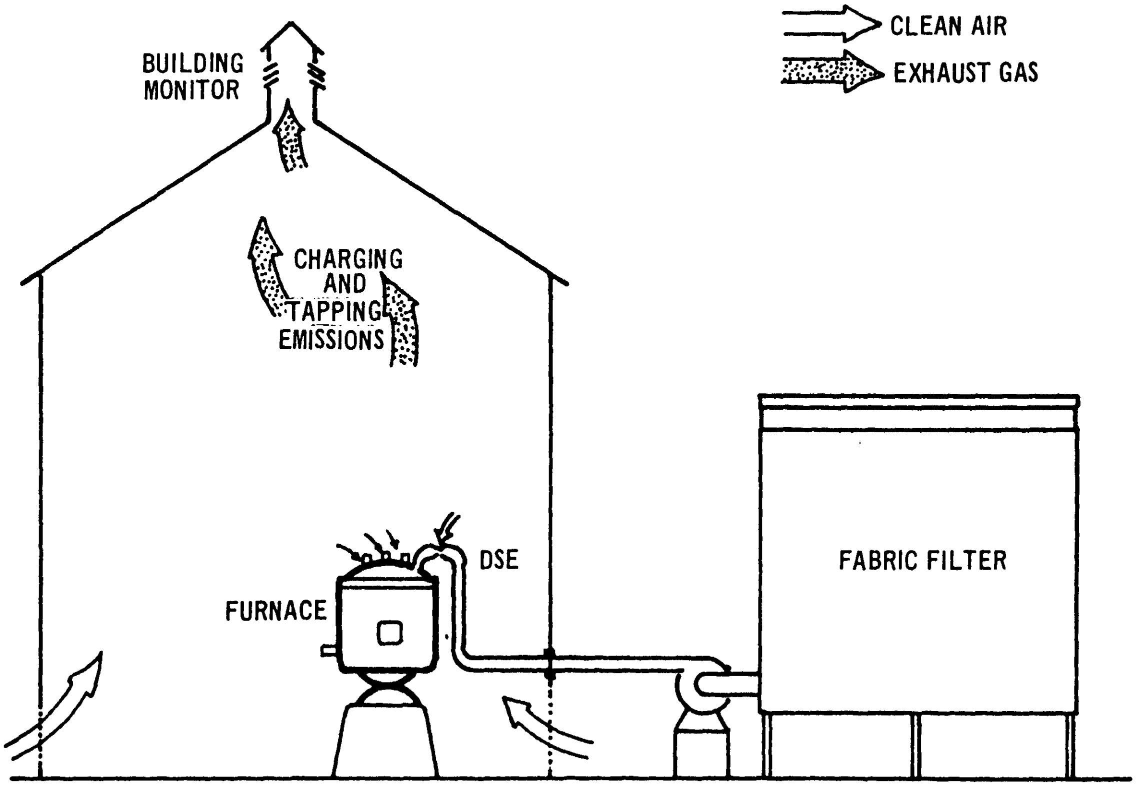
7.4.4.2 Process Emission Sources and Factors

Carbon monoxide is generated by reaction of the carbon electrodes or carbon in the steel scrap with blown oxygen or iron oxides. Major exhaust gas components include oxygen, nitrogen, carbon dioxide, carbon monoxide, and gaseous fluoride.[28] Exhaust gas composition is influenced by the stage of the heating process: typically, the CO content rises sharply at the beginning of the melt and again during oxygen lancing. The exhaust gas leaves the furnace at temperatures of 650°C to 980°C (1200°F to 1800°F).[39]

Data describing carbon monoxide emissions from direct arc furnaces are limited. However, testing at one source indicated that carbon monoxide emissions may be as high as 3 kilograms per metric ton (6 lb/ton) of steel produced.[40] Recent EPA estimates of carbon monoxide emissions from both submerged- and direct-electric arc furnaces were 205,700 metric tons (226,800 tons) in 1977.[2] No process-specific emissions data were available.

7.4.4.3 Control Techniques

The only known technique for controlling carbon monoxide emissions from direct-arc furnaces is the direct shell evacuation system.[37] This system, shown in Figure 7-20, withdraws all potential emissions from the furnace before they escape and mix with the ventilation air. The furnace roof is constructed so that it can be elevated and rotated aside during top charging and tapping and slagging. During furnace operation, the direct shell evacuation system maintains a negative pressure within the furnace. As a result, air is drawn into the furnace around the electrodes and through a small gap in the roof. It then flows through the exhaust duct, where it not only cools



Source: Reference 37

FIGURE 7-20. DIRECT SHELL EVACUATION (DSE) SYSTEM OPEN ROOF the exhaust gas but also promotes combustion of large amounts of carbon monoxide present in the gas.[37] On small steel furnaces direct evacuation is not always a viable option because of (1) lack of space for fourth hole in the furnace roof and (2) pressure fluctuations in furnace which are too rapid for automatic control of dampers in the exhaust duct.[41]

One source has estimated that direct shell evacuation systems achieve about 85 percent carbon monoxide emission reduction.[37] However, these systems cannot be used in producing some types of alloy steels. During the production of some alloys, a second "reducing" slagging takes place. Air will oxidize these slags and prevent their removal.[37]

An additional problem with direct shell evacuation systems is their inability to function during top charging, tapping, and slagging. When the roof is rotated during these times, much of the carbon monoxide in the exhaust gas is not oxidized and rises directly through the roof of the shop.[37]

7.4.4.4 Cost of Controls

As discussed in previous sections, it is difficult to separate costs of carbon monoxide emission controls from costs of particulate control systems. In almost all cases, the same ventilation and transport systems will be used for both pollutants.

7.4.4.5 Impact of Controls

Emissions Reduction -- Direct shell evacuation systems have been found to achieve up to 85 percent reductions in carbon monoxide emissions from direct arc furnaces. When applied, these systems should substantially reduce total mass emissions of carbon monoxide from this source.

Environment -- Industry data indicate that nitrogen oxide (NO_x) emissions from direct arc furnaces are less than 0.05 kilograms per metric ton (0.1 lb/ton) of steel produced.[37] Thus, almost all NO_x formed during combustion of carbon monoxide in a direct shell evacuation system would result from the fixation of atmospheric nitrogen. NO_x emissions should not increase to significant levels as a result of carbon monoxide emissions reduction.

Energy Requirements -- If exhaust gas from direct arc furnaces is burned in a direct shell evacuation system, no supplementary fuel (other than air) will be necessary to maintain combustion. Although the exhaust gas may contain up to 20 percent CO during parts of the furnace cycle, average concentrations are too low for the exhaust gas to be used as process fuel.[37]

7.4.5 Gray Iron Cupola

7.4.5.1 Process Description

Cupolas, the most common furnaces for making iron castings and ingots, may be water cooled or refractory lined. Air blown through a bed of coke near the bottom of the cylindrical furnace rises through alternating charges of pig iron and scrap, limestone flux and coke. Descending charges are preheated by rising gases which may vary between 260° and 1200°C (500° and 2200°F), depending on the blast air rate, the preheat temperature, the charge door induced draft rate and the cycle of operation.[42] Temperatures of the cupola exhaust gases drop with the addition of each charge and are cooled considerably from cold outside air induced through the charge door. Molten iron and slag are tapped below the ports which introduce the blast air into the furnace. Furnaces which preheat the combustion air are called hot-blast cupolas. The air may be heated from an external source or with an off-gas heat recovery system. One system supplies the heat by recuperating the heat of the flue gases after combusting the CO.[42]

Cupolas range in size from 70 centimeters to 395 centimeters (27 inches to 155 inches) in diameter producing one ton per hour in the smallest jobbing foundries to more than 90 metric tons per hour (100 ton/hr) in captive foundries.[43] Blast air is usually supplied at the rate of 935 cubic meters per metric ton (30,000 cubic feet per ton) of melt capacity.[42]

7.4.5.2 Process Emission Sources and Factors

Exhaust gases from the cupola furnace are a significant source of CO emissions. Recent EPA estimates indicate that 1,020,800 metric tons (1,125,200 tons) of carbon monoxide were produced in cupola furnaces in 1977.[2] Average carbon monoxide emissions have been estimated to be 72.5 kg/metric ton of metal charged (145 lb/ton).[5] Actual carbon monoxide emissions may vary with the quality of charge material, the volume and rate of combustion air, and the melting zone temperature.[38]

7.4.5.3 Control Techniques

Afterburners are applied to cupola furnaces to reduce CO emissions.[38] Besides reducing carbon monoxide emissions to 4 or 5 kilograms per metric ton (8 to 10 pounds per ton) of iron melted, afterburners also reduce the hazard of explosion and consume oil vapors and coke breeze, minimizing damage and maintenance on particulate collection devices.[38]

The afterburner chamber is located in the top part of the cupola stack above the charge door. For best gas-flame contact without quenching, the off-gas, multiple burners are installed just below the charge door. Induced drafts from the charge door are essential to insuring sufficient mixing and providing ample combustion air. To avoid stratification of the gas stream, the exhaust from the large cupolas requires a mixing aid, such as an inverted cone in the afterburner chamber, with burners angled to encourage swirling.

Recent laboratory research indicates that the carbon monoxide content of the flue gas may be reduced to one percent or less without an afterburner, achieving control efficiencies greater than 90 percent.[44] The study suggests injecting the proper amount of air at a point in the furnace below the charge door where temperatures are at least 700°C (1300°F). More details may be obtained from Reference 44.

7.4.5.4 Cost of Controls (Corrected to 1978)

Reported installed costs for afterburners were \$12,000 to \$20,000,[42] depending mostly on the size of the cupola. Fuel for the natural gas afterburners makes up the major part of the annual operating expense which is estimated at \$12,000 for an average sized foundry and may exceed \$75,000 for the cupolas melting 45 metric tons (50 tons) per hour or more, assuming 32 kilojoules required per second per metric ton of metal melted (100,000 Btu/hr/ton), a 6,000 hour per year operation and natural gas purchased at \$2.50 per gigajoule (10^6 Btu). Afterburners installed on water-cooled cupolas require more heat than refractory-lined cupolas since they maintain a hotter contact area. Charging height also affects control costs. Increasing charging height reduces off-gas temperatures. Consequently, larger afterburner systems are required which use more fuel.[43]

Charge door enclosures can decrease afterburner heat loads by reducing the amount of cold air mixed into the stack gases. The true value of an enclosure, however, depends on its reliability. A poorly constructed enclosure may interfere with the charging mechanism, demanding constant repairs and costly delays. Installing charge door enclosures may produce other undesirable side effects. Reducing the amount of induced air may affect afterburner efficiency by restricting combustion air under the necessary volume and by inhibiting stack gas mixing. Increasing charging height increases afterburner fuel costs because more fuel must be used to compensate for the lower gas temperatures.[43]

7.4.5.5 Impact of Controls

Emissions -- Only four percent of the facilities operating in 1975 reportedly controlled carbon monoxide emissions.[34] As mentioned previously, use of an afterburner could reduce carbon monoxide emissions from 72.5 kilograms per ton (145 lb/ton) of metal charged to 4 to 5 kilograms per metric ton (8-10 lb/ton). This reduction would result in estimated national emissions of 66,000 metric tons/yr (72,700 tons/yr), based on recent emissions data.[2]

Environment -- The application of afterburners would reduce emissions of hydrocarbons by combusting them along with the CO. The need for supplemental fuel introduces the possibility of SO_2 emissions from the fuel source. As with any combustion device used as a control device, NO_x emissions will be increased.

Energy Requirements -- A range of burner duties was reported at 1.5 megajoules per second per cupola (5,200,000 Btu/hr/cupola) to 4.7 megajoules per second per cupola (16,000,000 Btu/hr/cupola).[44] Typical cupola production data may be obtained from Reference 44. The same source indicates that fuel requirements are quite varied and suggests that in some cases the CO combustion might be self-sustaining.[44] Increasing charging height increases energy requirements since more fuel must be used to compensate for the lower temperature of the off-gases.[43]

7.4.6 Sintering Furnace

Sinter plants prepare small particles of iron ore and recycled flue dust for blast furnace smelting by agglomerating them into larger particles (sinter) suitable for blast furnace use. In 1976, over 40 sinter plants were operating in the U.S., with a total production capacity of over 54 x 10^6 metric tons (60 x 10^6 tons).[45]

7.4.6.1 Process Description

The sintering process converts fine ore concentrates, coke fines, limestone fines, blast furnace flue dust, and miscellaneous fines into an agglomerated product that is large enough and strong enough to be charged to a blast furnace. The mixture is placed on a travelling grate. Combustion air is added and the mixture is ignited. Temperatures of 1300-1500°C (2400-2700°F) are maintained as the mixture burns and forms a fused mass. The sinter product is then cooled, crushed and screened for use in the blast furnace.[4]

7.4.6.2 Process Emission Sources and Factors

The major source of carbon monoxide emissions from sintering furnaces is incomplete combustion of coke fines. The CO exhausts through the windbox, a compartment under the sinter bed which provides uniform distribution of combustion air as it passes through the sinter bed. Exhaust gas may leave the windbox at rates of 120 to 250 Nm^3/sec (250 x 10^3 to 530 x 10^3 scfm).[45] Gas temperature is typically 200°C (400°F) or less.[45] Uncontrolled emissions from this point have been estimated by one source to be 22 kilograms CO per metric ton of sinter product (44 lb/ton).[5] Another more recent source gave a higher estimate of 26 kg/metric ton (52 lb/ton).[45]

No techniques were reportedly used by U.S. sinter producers to control carbon monoxide emissions. Only one state regulates carbon monoxide emissions, and none of the affected sintering plants have properly complied with its control regulations.[46]

A recent EPA estimate of carbon monoxide emissions from sinter production indicated that total mass emissions were 624,700 metric tons (688,600 tons) in 1977.[2] The amount of carbon monoxide actually emitted from each plant depends on the coke content of the sinter charge, processing size, and the completeness of combustion.[45]

7.4.6.3 Control Techniques

Little data were reported regarding carbon monoxide controls used in sinter production. As was previously mentioned, no controls are reportedly currently in use in the U.S. The only applicable control devices appear to be afterburners or thermal incinerators, although these would be costly. Catalytic incinerators are not feasible because trace amounts of phosphorus in the exhaust gas would foul the catalyst.[45]

Carbon monoxide concentrations in the windbox exhaust gas can be reduced by 90 percent if an incinerator (afterburner) combustion chamber temperature of 680-800°C (1250-1500°F) is maintained.[45] The energy content of the exhaust-gas is too low to maintain combustion at these temperatures, so supplementary fuel is required.

A new development in sinter plant design may benefit the operation of afterburners for CO control. This method produces a 65 to 75 percent lower exhaust-draft than conventional sintering processes.[47] Waste gases also leave the process around 340°C (650°F), which, combined with the lower blow rate, could reduce the incineration energy load.[47] Further details are given in Reference 47.

7.4.6.4 Cost of Controls

Control costs for new plants have been taken from estimates for a thermal incinerator with and without heat recuperation installed after gas cleaning equipment.[45] Table 7-15 gives costs corrected to 1978 dollars. The annualized capital cost is small compared to the annual operating cost, largely because of the quantity of natural gas necessary to heat the enormous exhaust gas flow. Control costs for existing facilities do not differ markedly from those given in the table for new plants. As the table indicates, the cost of afterburner use is high, even with heat recovery.

7.4.6.5 Impact of Controls

Emissions Reduction -- If control systems with 90 percent carbon monoxide removal efficiency were applied industry-wide to the sintering industry, annual emissions could be reduced by 562,000 metric tons (620,000 tons). This reduction would result in total annual CO emissions of 62,500 metric tons (68,900 tons) based on 1977 emissions data.

TABLE 7-15

THERMAL INCINERATION COSTS IN SINTER PLANTS, 1978

CAPACITY metric tons of sinter/day (tons/day)	ANNUAL OPERATING COST ($ Million)	ANNUAL AMORTIZATION COST ($ Million)	TOTAL COST $/metric ton of sinter ($/ton)
Without heat recovery			
13,500 (15,000 tons/day)	31.9	.066	7.05 (6.40/ton)
6,300 (7,000 tons/day)	14.9	.057	7.07 (6.41/ton)
900 (1,000 tons/day)	2.1	.037	7.21 (6.54/ton)
With heat recovery			
13,500 (15,000 tons/day)	21.5	.151	4.78 (4.34/ton)
6,300 (7,000 tons/day)	10.1	.115	4.81 (4.36/ton)
900 (1,000 tons/day)	1.5	.057	5.02 (4.55/ton)

Operating assumptions:

1. Inlet volumetric flow rate: 0.05 Nm^3/sec/metric ton-per-day (87.8 scfm/ton-per-day) of sinter
2. Inlet temperature: 160°C (320°F)
3. Outlet temperature: 760°C (1400°F)
4. Residence time: 0.5 seconds
5. Afterburner life: 5 years

Source: Reference 45

Environment -- The use of incineration devices for carbon monoxide emission control would increase emissions of nitrogen oxides (NO_x) from sintering furnaces. This increase would be due to the large amounts of natural gas necessary to maintain combustion of the exhaust gas.

If it becomes necessary to use fuel oil rather than natural gas as supplementary incinerator fuel, sulfur oxides (SO_x) emissions would increase. The amount of SO_x emitted would depend on the sulfur content of the fuel oil and the quantity of oil consumed.

Energy Requirements -- An incinerator, operating at 90 percent efficiency in a typical 900 metric ton/day (1,000 ton/day) sinter plant, would require 31.3 megajoules/sec (1.1×10^8 Btu/hr).[45] Assuming an exhaust gas flow rate of 41 Nm^3/sec (88,000 scfm), the energy required per normal cubic meter would be 0.8 megajoules (21 Btu/scf). These amounts would be reduced if the exhaust gas was preheated.

7.5 PETROLEUM REFINING

Petroleum refining is the process of converting crude oil into salable products. Currently there are over 240 refineries in the United States processing over 2.2 million cubic meters (14 million barrels) of crude oil per day.[48] Refineries are located in 39 states with the majority of refining capacity found near the coasts.[48] Refinery sizes vary considerably from a processing rate of 500 m^3/day (3,000 bbls/day) to more than 64,000 m^3/day (400,000 bbls/day).[48]

There are several significant sources of carbon monoxide from petroleum refining. These are catalytic cracker regenerators, fluid coking, and sulfur plants. The following sections provide a brief process description of these sources and also an assessment of carbon monoxide control technology for the petroleum refining industry.

7.5.1 Catalytic Cracking

7.5.1.1 Process Description and Emissions

Catalysts are utilized by the refining industry in the operations of cracking, reforming, hydrotreating, isomerization, hydrocracking, alkylation, and polymerization. Of these, cracking catalysts are the only types which require regeneration frequently enough to produce significant amounts of CO.[49]

Several types of catalytic cracking units are presently in operation; fluid catalytic cracking (FCC) units and moving bed designs such as Thermofor (TCC) and Houdriflow (HCC) cracking units. Table 7-16 gives a breakdown of catalytic cracking capacity in the United States as of January 1978.

TABLE 7-16

DOMESTIC CATALYTIC CRACKING CAPACITY, 1978

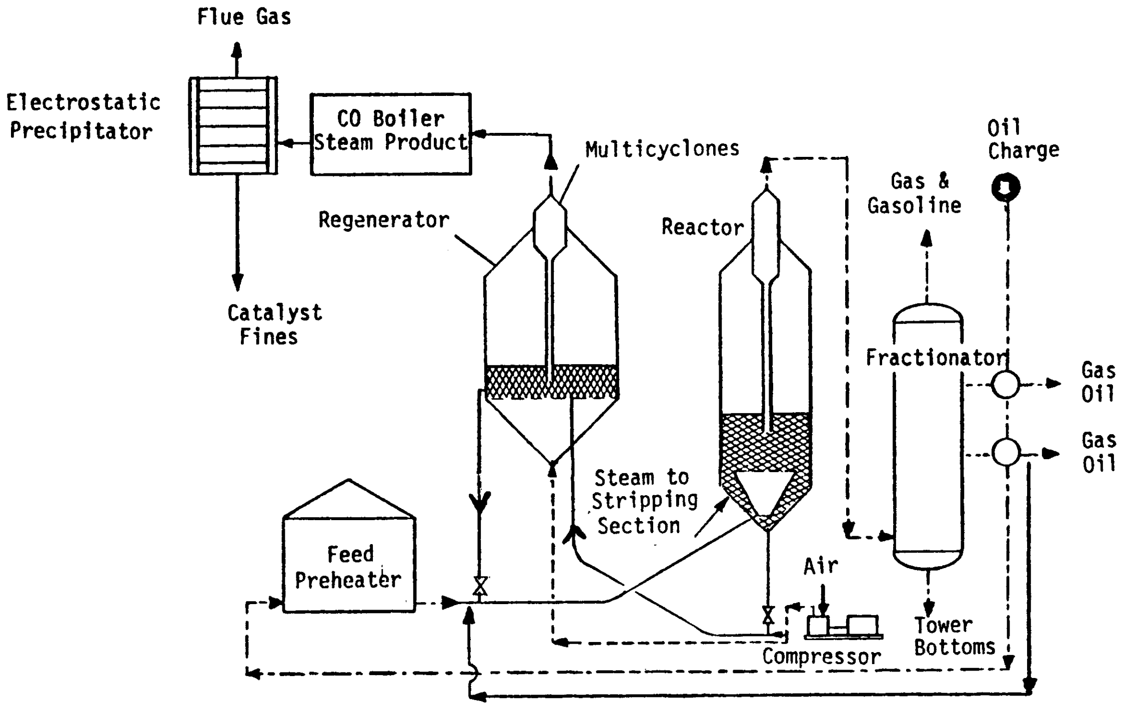
UNIT TYPE	FRESH FEED m^3/stream day	FRESH FEED (bbl/stream day)	% OF TOTAL FEED CAPACITY	# OF UNITS IN OPERATION
FCC	742,700	(4,670,000)	94.2	123
TCC	37,200	(233,800)	4.7	17
HCC	8,190	(51,500)	1.0	3

Source: Reference 48

Figure 7-21 shows a diagram of a typical FCC unit.[50] Hot regenerated catalyst, mixed with hydrocarbon feed, is transported into the reactor. The reactor contains a bed of powdered catalyst which is kept in a fluidized state by the flow of vaporized feed material and steam. Cracking of the feed, which occurs in both the riser leading to the reactor and in the fluidized bed, causes a deposit of coke to form on the catalyst particles. A continuous stream of spent catalyst is withdrawn from the reactor. The catalyst is steam stripped to remove hydrocarbons and is conveyed to the regenerator by airflow. The hydrocarbon vapor from the reactor is fractionated into a variety of products including light hydrocarbons, cracked gasoline, and fuel oil while a portion of the fractionator bottoms is recycled to the reactor.[50]

Additional air is injected into the regenerator to burn off the coke deposit and the regenerated catalyst is continuously returned to the reactor. Heat added to the catalyst during coke burn-off furnishes much of the required heat for the cracking reaction.[51]

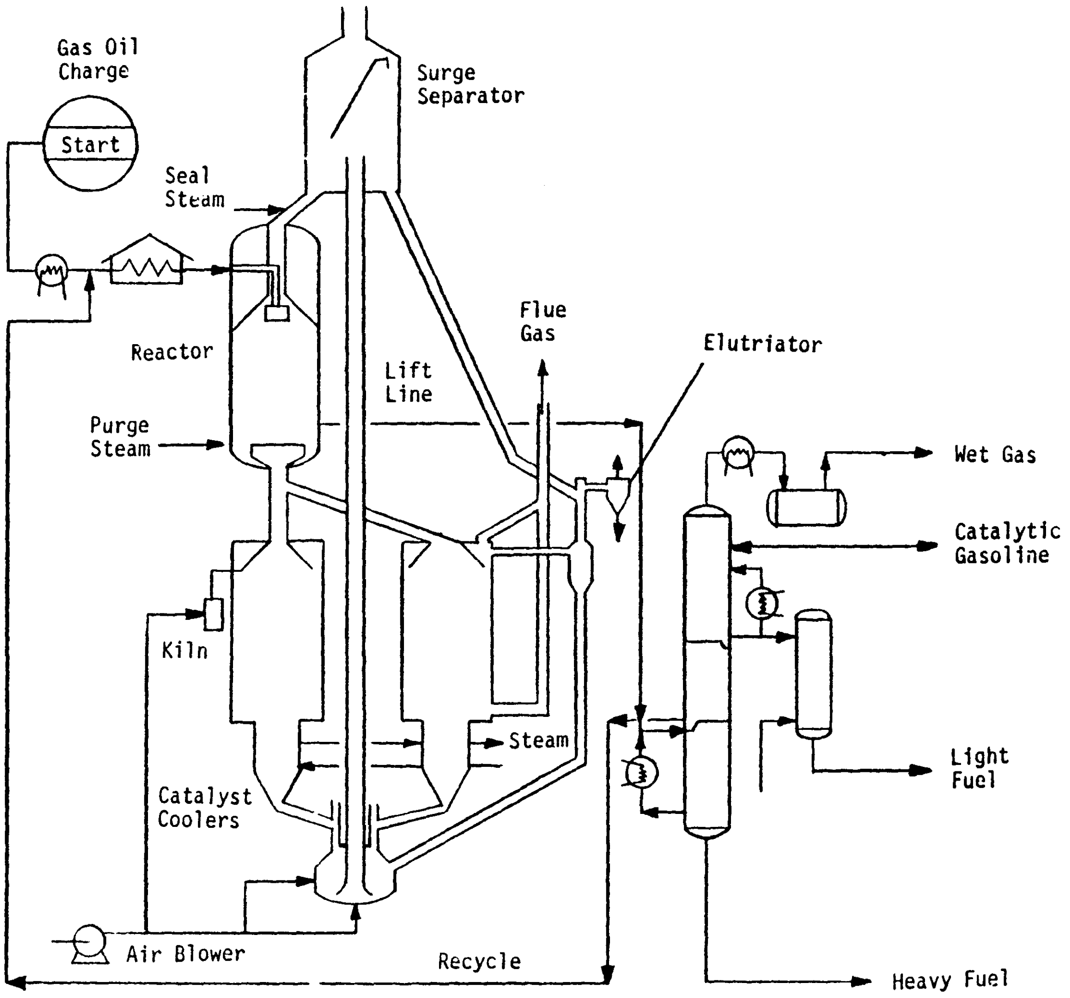
Thermofor and Houdriflow catalytic cracking units utilize beaded or pelleted catalysts. Regenerated catalyst and vaporized feed enter the top of the reactor chamber and travel concurrently downward through the vessel. The catalyst is purged with steam at the base of the reactor and travels by gravity into the regenerator chamber. Combustion air is admitted at a controlled rate to burn off coke deposits. From the bottom of the regenerator, the catalyst is conveyed by airlift to a surge hopper above the reactor. A diagram of a typical Thermoflor catalytic cracking unit is given in Figure 7-22.



FLUID CATALYTIC CRACKING UNIT

Source: Reference 50

FIGURE 7-21. FLUID CATALYTIC CRACKING UNIT



Source: Reference 52

FIGURE 7-22. THERMOFLOR MOVING-BED CATALYTIC CRACKER

Carbon monoxide is formed when the coke deposits are burned off the cracking catalyst during regeneration. EPA emission factors for conventional uncontrolled fluid catalytic cracking units and moving bed units are 39.2 and 10.8 Kg CO/m^3 of fresh feed (13,700 and 3,800 pounds CO per 1,000 barrels of fresh feed), respectively.[5] The exact amount of CO produced depends on the method of regeneration employed by the refiner. EPA estimates of total CO emissions from fluid and moving bed catalytic cracking operations are given in Table 7-17.

TABLE 7-17

EPA ESTIMATED 1977 UNCONTROLLED CO EMISSIONS FROM U.S. CATALYTIC CRACKING UNITS

UNIT TYPE	TOTAL U.S. CAPACITY m^3/stream day (bbl/stream day)	EMISSION FACTOR Kg CO/m^3 feed (lb CO/1000 bbl)	CATALYTIC CRACKING CO EMISSIONS metric tons/year (tons/year)
Fluid Catalytic Cracker	742,700 (4,671,000)	39.2 (13,700)	2,385,000 (2,629,000)
Thermoflor Catalytic Cracker	37,170 (233,800)	10.8 (3,800)	40,400 (44,500)
			2,425,100 (2,673,200)

Source: References 2, 5

With the advent of new catalysts, major design and operational changes have been incorporated in fluid catalytic cracking unit operation. By contrast, no major changes in moving bed type units have been observed and these units are being phased out.[48] Several of the operational changes in fluid catalytic cracking units that directly affect CO emissions are discussed below.

Conventional Fluid Catalytic Cracker Operation -- Coke is removed from cracking catalysts to restore their activity. Spent catalyst contains roughly 6 percent coke while coke levels on the regenerated catalyst vary from 0.2-0.3 percent.[54] The amount of air supplied to the regenerator is insufficient for complete combustion which results in flue gas CO concentrations of 5-10 percent.[54] The oxygen level in the flue gas is low enough so that combustion does not continue in the regenerator "dilute phase" where no catalyst heat sink is available. Combustion in the dilute phase, called afterburning, can result in damage to the catalyst, the cyclones, and other regenerator equipment due to high temperatures. To avoid equipment damage, the regenerator is operated below 620°C (1150°F).[53,54,55]

High Temperature Regeneration -- Zeolite catalysts first appeared on the market in the mid-1960's. The major features of these catalysts are summarized below:[54,56]

1) naphthenes and paraffins are cracked rapidly with excellent selectivity,

2) aromatic nuclei crack slowly with poor selectivity,

3) high hydrogen transfer rates are observed,

4) the rate of cracking is relatively unaffected by boiling range, and

5) catalyst activity is adversely affected by coke deposits which limit zeolite availability.

The use of zeolite catalysts has accelerated the trend to more fully regenerate these coke sensitive catalysts as even slight improvements in regeneration can provide substantial yield benefits. Very low carbon on regenerated catalyst (CRC) levels have been achieved using a technique called high temperature regeneration (HTR). The key to this process is complete conversion of coke to CO_2 within the regenerator. This situation is quite different from that of conventional regeneration where conversion of CO to CO_2 is minimized.[55] High temperature regeneration can be utilized in new units, or applied as a retrofit to existing units. The major features of high temperature regeneration are:

1) Extremely low levels of coke on the regenerated catalyst are possible. Typical values are 0.05-0.1 percent coke. Amoco Oil Company reported regenerated catalyst levels of 0.01 percent with their UltraCat regeneration technique.[50,55]

2) CO emission levels of 500 ppm in the regenerator flue gas can be obtained. This level is sufficiently low to meet federal New Source Performance Standards and most state emissions regulations.[55,57,58,59]

3) Complete regeneration increases catalyst activity which means a lower catalyst-to-oil ratio is possible. Thus, unit capacity can be increased if bottlenecks are removed from the rest of the process.[50,54,55,56,57]

4) Temperatures in the regenerator vary from 540-730°C (1000-1350°F). This is 40-65°C (100-150°F) higher than conventional regeneration. Since CO afterburn is possible, flue gas temperatures in the dilute-phase can be several hundred degrees higher than the dense-bed temperature.[51,55,57,58]

5) The extremely active catalyst produced from HTR is most effectively used in a short contact time riser cracking reactor. The advantage of riser cracking over bed cracking lies in avoiding secondary reactions such as the recracking of gasoline.[54,57]

6) Recovery of thermal energy in waste heat boilers.

7) Increased catalyst selectivity and the use of riser cracking can result in a 20 to 30 percent reduction in the amount of coke produced. Therefore, the increase in combustion air required to completely burn CO and coke can be offset in some cases by lower coke production such that overall combustion air usage can remain essentially constant.[50]

The operating conditions for conventional fluid catalytic crackers and units using high temperature regeneration are compared in Table 7-18.

TABLE 7-18

TYPICAL OPERATING CONDITIONS FOR FLUID CATALYTIC CRACKING

Reactor Temperature, °C (°F)	470 - 550 (885 - 1025)
Regenerator Temperature, °C (°F)	
Conventional Regeneration	540 - 590 (1000 - 1100)
High Temperature Regeneration	590 - 730 (1100 - 1350)
Coke Content of Spent Catalyst, Wt %	
Conventional Regeneration	6
High Temperature Regeneration	5
Coke Content on Regenerated Catalyst, Wt %	
Conventional Regeneration	0.2 - 0.3
High Temperature Regeneration	0.01 - 0.1

Source: References 50, 57

Existing fluid catalytic cracking units may be revamped to incorporate high temperature regeneration. The required changes to convert to high temperature regeneration depend on the design of the unit and the desired coke content on the regenerated catalyst. To withstand higher regenerator temperatures, steel components within the regenerator may require replacement by components made with more heat resistant materials such as chromium-nickel alloy stainless steel. Other modifications may include an improved combustion air distribution system or in the installation of a riser cracking reactor. In general, switching to high temperature regeneration increases the capacity of the process and some modifications in downstream equipment may be required to remove bottlenecks.[58,59]

Combustion Promotion Catalysts -- The most recent development in fluid catalytic cracking technology is the use of "promotion" catalysts to completely convert CO to CO_2.[59] The first type to become available (1975) was a fluid catalytic cracker catalyst modified with a small concentration of noble metal promoting agent.[59] In 1977, a number of manufacturers began producing a solid promoter. This powder is mixed with make-up catalyst, roughly 0.5-5 kg/metric ton (1-10 lb/ton) of fresh catalyst. Liquid promoters, injected directly into the regenerator, are also available.[59]

The advantage of using combustion promoters is that CO is converted to CO_2 within the dense-phase of the regenerator. This avoids the problem of CO afterburn in the regenerator dilute phase, a common problem in units using high temperature regeneration. Thus, in units where temperature limitations prohibit the use of high temperature regeneration, CO emissions below 500 ppm can be obtained using combustion promoting catalysts.[55] Essentially complete conversion of CO can be obtained with bed temperatures of 620-650°C (1150-1200°F).[55,57] However, regeneration of the catalyst is not quite as effective at the lower temperature and selectivity of the catalyst is slightly poorer in that more coke is produced.[57] The thermal energy from the regenerator is usually recovered through steam production.

7.5.1.2 Control Techniques

There are a variety of ways to control CO emissions in the flue gas of catalyst regenerators. The most widely used method is burning the flue gas in a carbon monoxide waste-heat boiler. In addition to reducing CO emissions, valuable thermal energy is recovered from the flue gas. The CO boiler produces steam from sensible heat in the flue gas as well as from hea produced by CO combustion. Carbon monoxide emissions from a properly operated CO boiler can be very low. In one study in which five CO boilers were sampled, CO levels in the flue gas of 0, 0, 5, 10 and 25 ppm were obtained.[57] Typical fluid catalytic cracker regenerator flue gas compositions before and after incineration in a CO boiler are listed in Table 7-19.

Thermoflor and Houdriflow catalytic cracking unit regenerators produce significantly less flue gas than fluid catalytic cracking unit regenerators and may not justify the installation of a CO boiler. Flue gas from these sources can be incinerated in a process heater.[57]

Another method of limiting CO emissions described earlier is high temperature regeneration. High temperature regeneration can be used with conventional catalysts or with combustion promotion techniques. CO emission levels of less than 500 ppm have been reported for fluid catalytic cracking units using this type of regeneration.[57,58]

Exxon Corporation has reported using a medium temperature regeneration technique in their fluid catalytic cracking units to obtain the benefits from improved catalyst selectivity without requiring the replacement of the regenerator internals. However, lower CO content in the flue gas means additional auxiliary fuel consumption in their CO boilers.[57,59]

TABLE 7-19

EMISSION RATES FROM FCC UNIT REGENERATORS, BEFORE AND AFTER CO BOILER

EMISSIONS	BEFORE CO BOILER	AFTER CO BOILER[a]
SO_2, ppm	140 - 3300	Up to 2700
NO_x (as NO_2), ppm	8 - 394	Up to 500
CO, % Vol.	7.2 - 12.0	0 - 14 ppm
CO_2, % Vol.	10.5 - 11.3	11.2 - 14.0
H_2O, % Vol.	13.9 - 26.3	13.4 - 23.9
N_2, % Vol.	78.5 - 80.3	82.0 - 84.2
Hydrocarbons, ppm	98 - 1213	-
Ammonia, ppm	0 - 675	-
Aldehydes, ppm	3 - 130	-
Cyanides, ppm	0.19 - 0.94	-
Particulates, grains/scf	0.08 - 1.39	0.017 - 1.03
g/m^3	0.18 - 3.18	0.039 - 2.36
Temperature, °C	538 - 645	250 - 440
°F	1000 - 1200	485 - 820

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[a] Emissions after the CO boiler will be affected by the operating conditions and the type of auxiliary fuel.

Source: Reference 57

Industry acceptance of high temperature regeneration and combustion promotion techniques has been very good given the short length of time that these methods have been available.[55] The types of regeneration methods currently employed by U.S. refiners are listed in Table 7-20.

7.5.1.3 Cost of Controls

Although the cost of new CO boilers is quite high, the associated fuel savings can make this an attractive investment, particularly if additional steam generating capacity can be utilized. A typical CO boiler, operating with a conventional fluid catalytic cracking unit, can recover approximately

400 megajoules/m^3 (60,000 Btu/bbl) of fresh fluid catalytic cracker feed.[20] Information on investment and operating costs for CO boilers is given in Section 6.2. In all but small refineries, the cost of CO boilers can be recovered in a few years.

The cost of converting a conventional fluid catalytic cracking unit to high temperature regeneration or promotion catalysts can vary over a wide range depending on the original design of the unit and the degree of regeneration desired. Insufficient information was available, however, to adequately develop capital and annualized costs for these control methods.

TABLE 7-20

CURRENT DOMESTIC FLUID CATALYTIC CRACKER REGENERATION TECHNIQUES (August 1978)

REGENERATION TECHNIQUE	% OF ALL FLUID CATALYTIC CRACKING UNITS THAT USE THIS TECHNIQUE	REMARKS
Conventional regeneration	53	Most units have CO boilers
High temperature regeneration	26	May be used in conjunction with a CO boiler
Combustion promoting catalysts	10	May be used in conjunction with a CO boiler
Combustion promotion, separate from catalyst	11	May be used in conjunction with a CO boiler

Source: Reference 60

7.5.1.4 Impact of Controls

Emissions Impact -- CO emission levels from fluid catalytic cracker regenerators are summarized in Table 7-21.

TABLE 7-21

EFFECT OF CONTROLS ON CO EMISSIONS FROM FCC REGENERATORS

CONTROL TECHNIQUE	TYPICAL EMISSIONS LEVEL
Conventional regeneration, (uncontrolled)	5-10% CO in regenerator flue gas; AP-42 emission factor 39.2 kg/m^3 (13,700 lb CO/1000 bbl) feed
Conventional regeneration, (CO boiler)	<50 ppm in CO boiler flue gas
High temperature regeneration or combustion promotion	200-2000 ppm CO in regenerator flue gas; <500 ppm CO can usually be obtained

Source: Reference 57

CO emissions from a properly operated CO boiler are nearly zero. This represents a control efficiency of greater than 99.5 percent.[20] The emissions from units utilizing high temperature regeneration or combustion promotion catalysts are roughly one percent of those from conventional units of the same feed capacity.[20] Assuming that roughly 50 percent of all FCC units use high temperature regeneration or combustion promotion and that all the remaining catalytic cracking units were controlled by CO boilers or other forms of CO incineration, annual CO emissions from this source could be reduced to an estimated 47,800 metric tons per year (52,500 tons/yr).

Environmental Impact -- Hydrocarbon emissions are reduced by the application of CO control techniques. Hydrocarbon levels of less than 10 ppm have been reported in the flue gas of high temperature regenerators as well as from CO boilers.[57] The combustion reactions seem to be rate-limited by the combustion of carbon monoxide, not the combustion of hydrocarbons.[57]

Temperatures within the CO boiler are above 980°C (1800°F) in order to promote complete combustion of carbon monoxide.[57] This is considerably hotter than the maximum temperatures observed in high temperature regeneration. Hence, NO_x emissions could be higher for fluid catalytic cracking units that utilize CO boilers due to production of thermal NO_x. Also, nitrogen compounds present in the auxiliary fuel supply can also contribute to NO_x emissions. Typical NO_x emission levels from CO boilers are 100-300 ppm. NO_x emissions from high temperature regeneration units are somewhat lower.[57]

The amount of sulfur oxides emitted from catalytic cracking units depends on the sulfur content of the feed and the amount of coke burned. Adding a CO boiler to an existing unit will result in increased SO_x production due to sulfur compounds in the auxiliary fuel. A unit utilizing high temperature regeneration produces a more selective catalyst which can reduce coke yield. In addition to reducing total SO_x emissions, lower coke yield can result in reduced particulate emissions as well.[57]

Energy Impact -- The flue gas from uncontrolled fluid catalytic cracking units contains from 5-10 percent CO which represents a substantial energy loss if released to the atmosphere.[20] This energy is recovered in a CO boiler by producing steam. Often, the entire cost of a CO boiler can be justified on the basis of steam production alone.

Energy recovery from high temperature regeneration is about the same as for CO boilers, estimated at 400 megajoules/m^3 (60,000 Btu/bbl) of fresh feed.[20] This energy manifests itself in the increased yield of valuable liquid products and increased waste heat boiler steam production resulting from higher flue gas temperatures.[20]

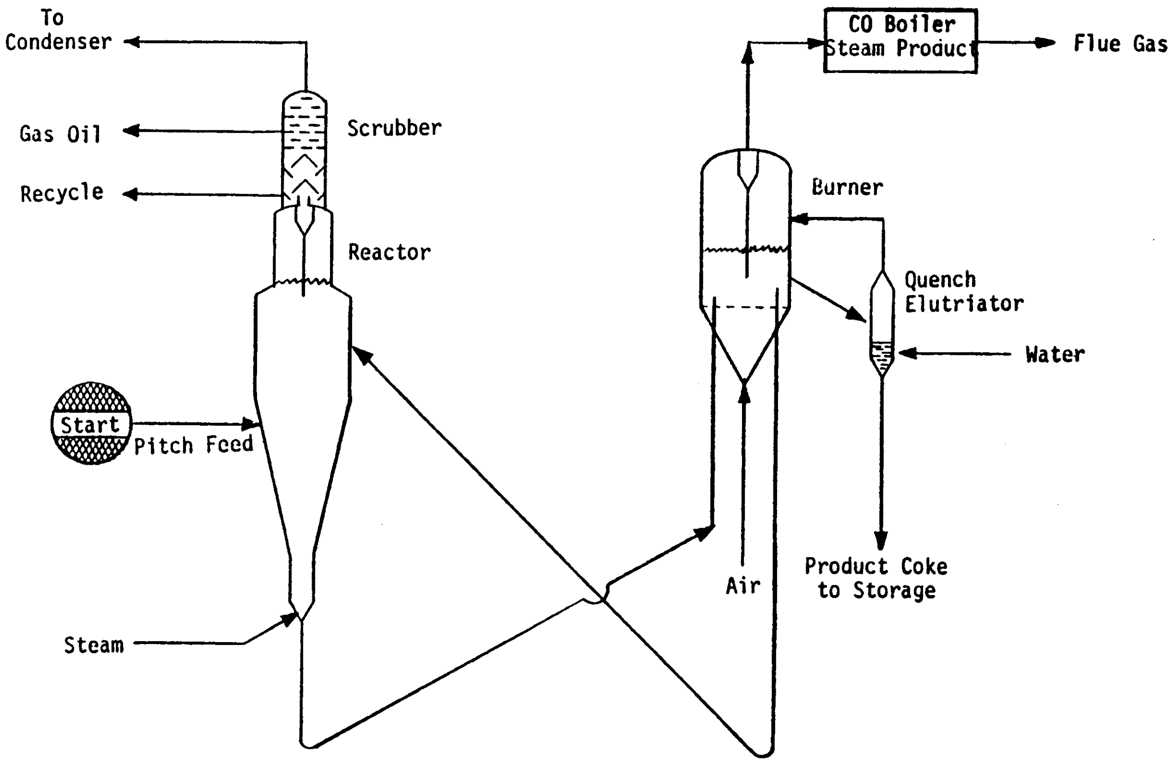
7.5.2 Fluid Coking

7.5.2.1 Process Description and Emissions

Coking processes convert residual oils, tars and resins into lighter, more valuable liquid products and coke. Two processes, delayed and fluid coking, account for most of the domestic petroleum coke production. However, only fluid coking results in a discharge of carbon monoxide.[48] There are only five fluid cokers currently in operation in the U.S.[48]

Fluid coking is a continuous thermal cracking process that involves the injection of feed into a fluidized bed of hot coke particles. The hot oil is cracked and carbon is deposited in thin layers on the coke particles. The bed is kept fluidized by the injection of steam. The coke particles travel from the reaction to a burning chamber where approximately 25 percent of the coke is burned to provide process heat. The heated coke particles (600-650°C, 1110-1200°F) circulate back to the reactor section. Since more coke is produced in the reactor than is burned, a coke product stream is withdrawn. The coke produced in fluid coking is unsuitable for most industrial uses. Consequently, most of this coke is sold as fuel or is used in the refinery to produce steam.[52,61] A diagram of a fluid coking unit is given in Figure 7-23.

Typical operating conditions for fluid coking are presented in Table 7-22.



Source: Reference 52

FIGURE 7-23. FLUID COKING PROCESS

TABLE 7-22

TYPICAL FLUID COKER OPERATING CONDITIONS

	REACTOR	BURNER
Temperature, °C	510	620
°F	950	1150
Pressure, kilopascals	170	180
psig	10	11
Bed Velocity, m/sec	.30 - .91	.61 - .91
ft/sec	1 - 3	2 - 3
Bed Depth, m	9.1 - 15	3.0 - 4.6
ft	30 - 50	10 - 15

Source: Reference 62

Carbon monoxide is formed in the burner section where coke is burned in limited air. It is estimated that CO emissions average 86 kg/m^3 (30 pounds per barrel) of fresh feed.[49] The energy content of the flue gas can be recovered by burning in a CO boiler, or, if the CO content is high enough, the flue gas could be used to fire a process heater. All five domestic fluid cokers presently in operation utilize one or the other of these methods.

The most recent advancement in coking processes is Flexicoking, developed by Exxon Research and Engineering.[20] Flexicoking integrates conventional fluid coking with coke gasification. The gaseous products are referred to as coke gas. The coke gas contains considerable quantities of carbon monoxide, hydrogen, carbon dioxide and water vapor and it may be substituted for refinery fuel gas or natural gas to fire process heaters or boilers. No commercial Flexicokers have yet been installed in the United States.[20]

7.5.2.2 Control Techniques

Control techniques for CO emissions from fluid cokers consist of burning CO in either a CO boiler or a process heater. As summarized in Table 7-23, all domestic fluid coking capacity is controlled by one or the other of these methods.

TABLE 7-23

CO CONTROLS ON DOMESTIC FLUID COKING UNITS

REFINERY LOCATION	REFINERY CRUDE CAPACITY, m^3/stream day (bbl/stream day)	FLUID COKING CAPACITY, m^3/stream day (bbl/stream day)	CO CONTROL METHOD
Exxon			
Benicia, Ca.	16,200 (102,000)	3,910 (24,600)	Flue gas used to fire crude pipestills
Billings, Mont.	7,300 (46,000)	1,190 (7,500)	CO boiler
Tosco			
Avon, Ca.	20,000[a] (126,000)	6,680 (42,000)	CO boiler
Bakersfield, Ca	6,360 (40,000)	1,110 (7,000)	CO boiler
Getty			
Delaware City, Del.	23,850 (150,000)	7,000 (44,000)	CO boiler

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[a] bbl/calendar day

Source: Reference 49

7.5.2.3 Cost of Controls

Chapter 6 contains a detailed presentation of capital and annualized costs for CO boilers. These costs are presented graphically in terms of dollars per normal cubic meter per second ($/scfm) with several curves per graph showing the effect of the heating value of the gas on annualized costs. Therefore, given a representative flow rate and heating value of the burner off-gas, control costs for CO boilers can be estimated.

The flow rate and heating value of the off-gas was estimated, based on the following assumptions:

1) coker feed density - 1.0 g/cm^3 (360 lb/bbl)[62]
2) coke production - 28 wt % of fresh feed[62]
3) coke burnoff rate - 25% of total coke production[62]
4) CO production rates - 85 kg/m^3 (30 lb/bbl) of fresh feed[50]

Using these values, the off-gas flow rate is estimated at 534 cubic meters of gas per cubic meter of fresh coker feed (3000 scf/bbl feed). The heating value of the gas is 1.61 megajoules per normal cubic meter (43 Btu/scf).

7.5.2.4 Impact of Controls

Emissions -- At the present time, CO emissions from all five domestic fluid coking units are controlled, either by CO boilers or by incineration in a process heater.[61]

Environmental Impact -- The application of CO boilers or other methods of gas incineration to control CO emissions will have both positive and negative impacts with respect to other pollutant discharges. The positive impact includes the combustion of some of the particulates which escape from the burner section cycle. The negative impacts include increased levels of SO_2 and NO_x.

Increased SO_2 emissions will occur if supplemental fuel is required. Most of the sulfur in this fuel will be discharged as SO_2.

Temperatures within the CO boilers are above 980°C (1800°F) in order to promote complete combustion of carbon monoxide. At this temperature, NO_x can be formed from elemental nitrogen and oxygen which are present during the combustion process. In addition, nitrogen compounds in the burner off-gas or the supplemental fuel can also form NO_x. Typical NO_x emission levels from CO boilers are 100-300 ppm.[57]

Energy Impact -- The burner off-gas from fluid coking units contains substantial quantities of CO which would represent a considerable energy loss if released to the atmosphere. This energy is recovered in a CO boiler by producing steam. Often the entire cost of a CO boiler can be justified on the basis of steam production alone.

7.5.3 Sulfur Plants

7.5.3.1 Process Description and Emissions

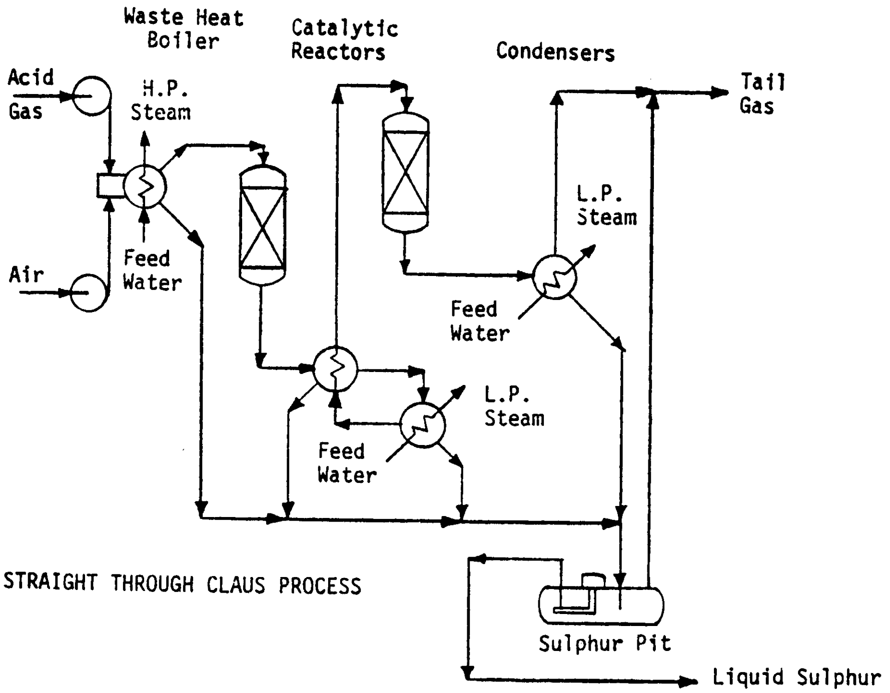
Claus sulfur plants -- Many refineries utilize a Claus sulfur plant to recover elemental sulfur from H_2S laden gas streams produced within the refinery. The first step in the process is the oxidation of part of the H_2S stream to SO_2.[63] Sulfur is then formed in two to four catalytic reactor stages by the Claus reaction:

$$2\ H_2S + SO_2 \rightleftarrows \frac{3}{n} S_n + 2\ H_2O$$

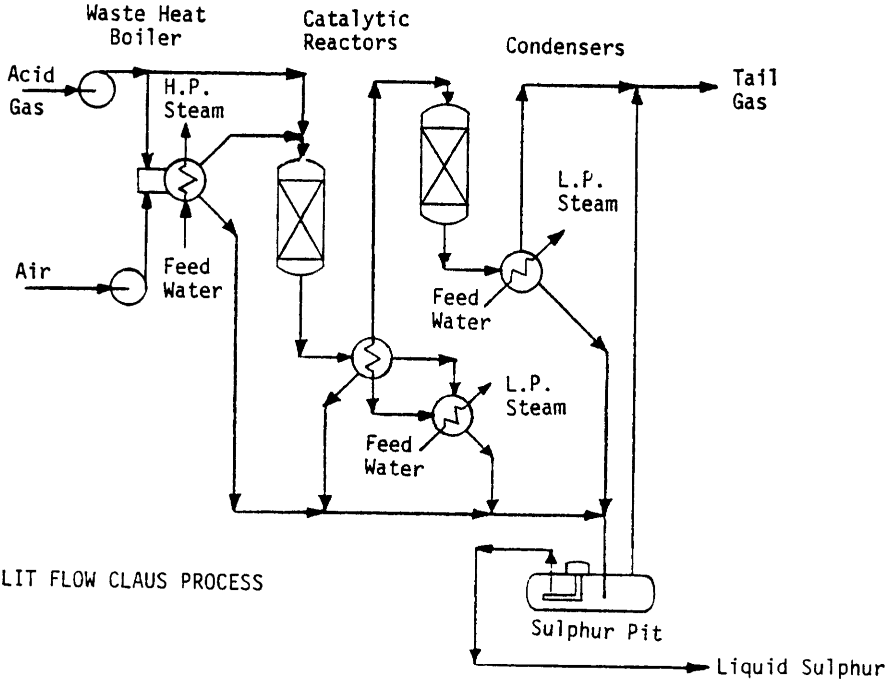
As indicated in Figure 7-24, several flow schemes are available for the Claus process.[64] In the most common type, the "once through" design, the H_2S feed stream is burned in a limited amount of air to convert one-third of the H_2S to SO_2. The Claus reaction is initiated in the combustion step and continues in the catalytic reactors. After each step, sulfur is condensed and is removed as a liquid.

In the bypass or split-flow designs, only one-third of the feed stream is burned. This stream is burned more completely and most of the H_2S is converted to SO_2. No sulfur is formed in the combustion step using this flow scheme. The hot gas from the furnace is cooled and combined with the bypass stream which then enters the reactor section. The split flow scheme is useful when the H_2S content of the feed is below 50 percent.[63] Additional fuel is necessary to support stable combustion at lower H_2S concentrations and the split flow design reduces fuel consumption by reducing the amount of inert gas which must be heated. Most refinery sulfur plant feed streams contain H_2S concentrations greater than 50 percent and the once-through design is the most prevalent.[63,65]

Carbon monoxide is formed in the combustion furnace from small amounts of hydrocarbon and carbon dioxide present in the feed stream. Since only partial combustion of the H_2S is desired, not enough oxygen is supplied to convert all the CO formed to CO_2. CO produced in the combustion process proceeds through the reactor-condenser section and ends up in the tail gas. The composition of the tail gas from a typical Claus unit is given in Table 7-24.



STRAIGHT THROUGH CLAUS PROCESS



SPLIT FLOW CLAUS PROCESS

Source: Reference 64

FIGURE 7-24. CLAUS SULFUR PLANTS

TABLE 7-24

TYPICAL CLAUS TAIL GAS COMPOSITIONS[a]

COMPONENT	SOUR GAS FEED VOLUME %	CLAUS TAIL GAS VOLUME %	THERMALLY INCINERATED TAIL GAS VOLUME %
H_2S	89.9	0.85	0.001
SO_2	0.0	0.42	0.89
S_8 vapor	0.0	0.10 as S_1	0.00
S_8 aerosol	0.0	0.30 as S_1	0.00
COS	0.0	0.05	0.02
CS_2	0.0	0.05	0.01
CO	0.0	0.22	0.10
CO_2	4.6	2.37	1.45
O_2	0.0	0.00	7.39
N_2	0.0	61.04	71.07
H_2	0.0	1.60	0.50
H_2O	5.5	33.00	18.57
H.C.	0.0	0.00	0.00
	100.0	100.00	100.00
Temperature, °C	40	140	400
°F	104	284	752
Pressure			
Kilopascals	150	110	100
Psig	6.6	1.5	0
Total Gas Volume[b]	--	3.0 x feed gas volume	5.8 x feed gas volume

---

[a] Two catalytic reactors - overall efficiency of 94%

[b] Gas volumes compared at standard conditions

Source: Reference 66

The tail gas still contains substantial quantities of H_2S which can pose a serious health hazard. Consequently, most refiners incinerate the tail gas before discharge to the atmosphere.[63] Incineration converts all sulfur values to SO_2 and simultaneously converts CO to CO_2.

Tail Gas Cleaning -- Claus plant sulfur removal efficiency depends on many factors including the concentration of H_2S in the feed, the number of reactor stages, and the level of impurities such as CO_2, water vapor, and hydrocarbons in the feed. Claus plant efficiency can range from 90 to 97 percent; however, increasingly strict state and Federal emission regulations can require up to 99.9 percent sulfur removal.[67] To achieve this efficiency tail gas cleaning is required.

Many different processes have been developed which can reduce the sulfur level in the tail gas. Several of these use incinerated tail gas as feed. Incineration converts sulfur species such as elemental sulfur, H_2S, COS, and CS_2 into SO_2, which is removed in the tail gas cleaning unit. The Wellman SO_2 recovery process, Shell's flue gas desulfurization process, and the SNPA Wet Contact Aid process are of this type.[67]

Carbonyl sulfide and carbon disulfide are produced from side reactions occurring in the thermal reactor section of the Claus plant.[64] Even with improved Claus unit catalysts, these contaminants are present in the tail gas and account for a sizable portion of the total sulfur loss. As an alternative to incineration, followed by the so-called "oxidation-scrubbing" systems, several tail gas cleaning processes have been designed which reduce all sulfur compounds to H_2S. Examples of this type of process are the

Beavon, SCOT, and Clean Air processes.[67] The reaction takes place at 260-320°C (500-610°F) over a cobalt/molybdenum catalyst with H_2, H_2O, and CO as reducing agents. Carbonyl sulfide and carbon disulfide are removed by hydrolysis;

$$COS + CS_2 + 3\ H_2O \rightleftarrows 3\ H_2S + 2\ CO_2$$

while SO_2 is hydrogenated:

$$SO_2 + 2\ H_2 \rightleftarrows S + 2\ H_2O$$

$$S + H_2 \rightleftarrows H_2S$$

The same catalyst is effective for hydrolysis of carbon monoxide via the water-gas shift reaction:

$$CO + H_2O \rightleftarrows H_2 + CO_2$$

The hydrogen produced here, together with that initially present in tail gas, is usually sufficient to convert all sulfur species to H_2S.[68] If not, additional hydrogen can be supplied from other units or from fuel rich combustion of natural gas ahead of the hydrogenation reactor. The H_2S is then removed using conventional H_2S removal techniques. For example, the Beavon process consists of a catalytic hydrogenation reactor followed by a Stretford H_2S removal system.

Carbon monoxide emission levels can be reduced using these "reduction-scrubbing" processes. Actual sampling data was limited; however, the developer of the Beavon process reported that tail gas CO levels of a few hundred ppm were typical.[69]

Tail gas compositions for a representative Beavon unit are given in Table 7-25.

TABLE 7-25

REPRESENTATIVE TAIL GAS COMPOSITIONS FOR THE BEAVON SULFUR REMOVAL PROCESS

COMPONENT	CLAUS TAIL GAS INPUT, VOL %	BEAVON PROCESS TAIL GAS, VOL %
H_2	2.5	Varies
CO	1.0	0.2
CO_2	10.0	14.0
N_2	56.2	80.8
H_2O	26.0	5.0
S	.07	0.0
H_2S	2.0	0.0
SO_2	1.0	0.0
COS	0.3	Less than 250 ppm
CS_2	0.3	0.0

Source: Reference 69

Two additional tail gas cleanup methods, the IFP and the Sulfreen processes, are continuations of the Claus reaction. Carbonyl sulfide and carbon disulfide are not removed by these processes and the tail gas usually requires incineration.[67]

7.5.3.2 Control Techniques

Carbon monoxide emissions from refinery sulfur plants can be reduced by incinerating the tail gas. The incinerator is a refractory lined vessel with one or more burners. Temperatures in excess of 650°C (1200°F) with residence times of 0.5-0.6 seconds were recommended by several manufacturers to assure complete conversion of H_2S to SO_2.[68] An auxiliary fuel supply such as natural gas or fuel oil provides the heat necessary for incineration as the heating value of the tail gas, estimated from the data in Table 7-24, is only 0.37-0.75 MJ/m^3 (10-20 Btu/scf).[66] Excess air levels of 20 - 30 percent are used and the flue gas is vented through a tall stack to disperse SO_2.

The recommended temperature and residence time given above is effective for conversion of H_2S to SO_2. However, higher temperatures, in the range of 870-980°C (1600-1800°F), are required to oxidize CO to CO_2. Therefore, additional auxiliary fuel may be necessary to provide a sufficiently high temperature for complete CO oxidation.

The primary motivation for installing an incinerator is to remove H_2S, not carbon monoxide. Although other methods of gas incineration such as flares or existing process heater could reduce CO emissions, these methods are not recommended for H_2S disposal because of inadequate gas residence time, insufficient stack height, or safety considerations.

Some tail gas treating processes have the capacity to reduce CO levels in the tail gas (see Table 7-25). These "reduction-scrubbing" systems utilize CO in the tail gas as a reactant in the catalytic reduction of all sulfur species to H_2S.

7.5.3.3 Cost of Controls

A detailed presentation of annualized costs for waste gas incinerators is given in Chapter 6. Capital costs are based on the volume of gas that requires incineration. An estimate of the tail gas volume, calculated from the data in Table 7-24, is 2.5 cubic meters per kilogram of sulfur recovered (40 scf/lb sulfur). The heating value of this gas, also estimated from the data in Table 7-24 is 0.37-0.75 megajoules/m^3 (10-20 Btu/ft^3). Using this information and the information in Chapter 6, annualized costs can be estimated for Claus plant tail gas incinerators.

7.5.3.4 Impact of Controls

Emissions -- Uncontrolled CO emissions from refinery sulfur plants have been estimated at 28800 metric tons per year (31700 tons/yr).[70] Based on a total refinery sulfur plant capacity of 8500 metric tons per day (9300 tons/day),[70] and a tail gas production estimate (calculated from data in Table 7-24) of 2.5 cubic meters per kilogram of sulfur (40 scf/lb) the average level of CO in the tail gas was estimated at 0.3 volume percent. Although only a limited amount of actual sampling data were located, typical CO levels from incinerated tail gas averaged approximately 0.1 volume percent. Assuming this level of CO in the incinerated tail gas with the incinerator fired at 25 percent excess air, controlled CO emissions from all refinery sulfur plants would be 11000 metric tons per year (12100 tons/year). This represents a reduction in total CO emissions of 62 percent. Further reduction in total CO emissions could be obtained by operating the incinerators at higher temperatures, although the benefits obtained would have to be balanced against higher fuel consumption and the possibility of increased NO_x emissions.

Environmental Impact -- The primary effect of Claus tail gas incineration is to convert all sulfur species to SO_2 before discharge to the atmosphere. Although actual sulfur emissions are not reduced, SO_2 is the least toxic of the sulfur compounds produced.

As is the case with all combustion operations, additional pollutants may be generated. Sulfur in the auxiliary fuel will oxidize to SO_2, adding to total sulfur emissions while nitrogen in the fuel, the tail gas, and the combustion air may be converted to NO_x. NO_x emission levels of 40 - 50 ppm have been reported from non-catalytic hydrocarbon vapor incinerators.[20] Claus incinerators are operated at higher temperatures, however, and NO_x emissions may be slightly higher.

Energy Requirements -- Auxiliary fuel must be used when incinerating Claus-unit tail gas. Part of the cost of this fuel can be offset by recovering heat from the incinerator flue gas. This heat may be utilized to preheat the incinerator feed or to generate steam. Heat recovery from the incinerator flue gas offers a way to reduce incinerator energy requirements at the expense of increased equipment costs. However, care must be taken in the design and operation of incinerators utilizing heat recovery to avoid corrosion problems which would occur at temperatures below the dew point of the flue gas.

7.6 PRIMARY ALUMINUM INDUSTRY

Aluminum is produced from alumina (Al_2O_3) which is contained in its hydrated form in bauxite ore. Alumina, after it has been separated from the ore, is reduced electrolytically to form aluminum metal.

Significant emissions of CO to the atmosphere result from the reduction process. Estimates for 1976 were 220,000 metric tons CO emitted per year (242,000 tons/yr).[71] No control methods expressly designed for CO control are currently in use.

This section contains a discussion of electrolytic reduction plant operation; CO emission sources; control methods for those sources; and cost, environmental impact, and energy requirements for possible control methods.

7.6.1 Process Description

The production of aluminum metal from alumina by electrolytic reduction is shown diagramatically in Figure 7-25. Alumina is decomposed in reduction plants by a continuous current flowing through an electrolytic cell which contains alumina dissolved in molten cryolite (Na_3AlF_6). The aluminum metal is deposited at the cathode, while oxygen passes to the carbon anode. The reaction between carbon and oxygen at the anode is one major source of CO emissions in the aluminum industry.

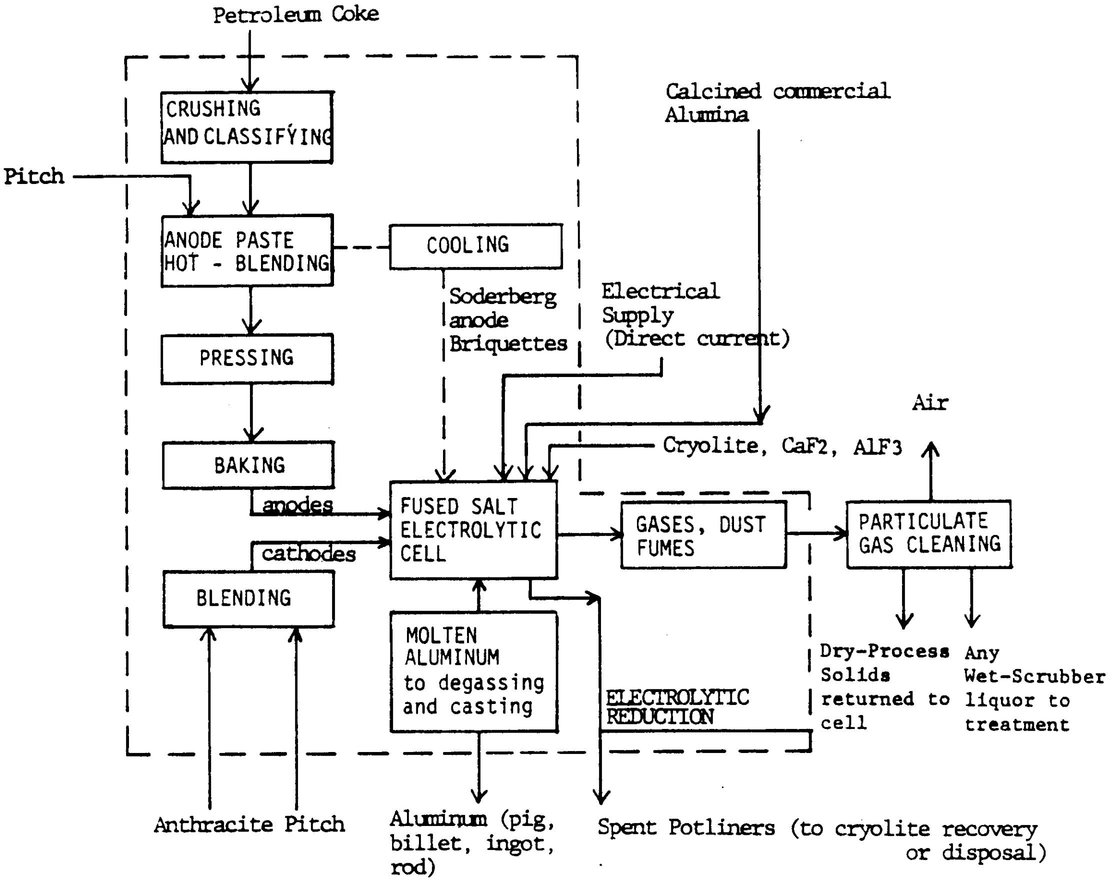


FIGURE 7-25. MAJOR PROCESSING PHASES IN PRIMARY ALUMINUM REDUCTION

A large number of reduction cells are usually linked together electrically in parallel to form a potline, the basic production unit of the reduction plant. Potline configuration, cell types, and cell dimensions vary according to the design and capacity of the individual aluminum reduction plants. A typical late design potline may consist of 180 cells. Such a potline operating at 83,000 kW would produce approximately 125 megagrams (275,000 pounds) of aluminum per day.[72]

The reduction cell, or pot, is a strongly reinforced steel box, lined with heat insulation and either prebaked carbon blocks or a rammed monolithic carbon liner inside the insulation. The carbon liner forms the cathode of the electrolytic cell and provides high electrical conductivity and good corrosion resistance to the highly reactive molten electrolyte. The carbon lining contains steel electric current collector bars that extend through the sides of the steel shell. The collector bars are connected to a ring collector bus which is connected to the main bus. The main bus is usually made of aluminum bars and serves as the electrical connection for a line of cells connected in parallel.

The anode, also made of carbon, is suspended over the steel pot shell and is immersed in the molten electrolyte. It is connected to the main bus system through flexible conductors.

Reduction cells are of two basic types, the prebake cell using multiple prebaked carbon anodes, and the Soderberg cell using one large self-baking anode.

7.6.1.1 Prebake Anode Cell

Modern prebake cells use a number of anodes suspended in the electrolyte. The anodes are press-formed or vibration molded from a carbon paste mixture of coke and pitch. They are then baked in anode bake furnaces, sometimes termed "ring furnaces." The off gases from the anode bake furnaces are one source of CO emissions in the prebaked anode plants.[72]

The anode bake furnaces are sunken pits with surrounding brick flues. Anodes are packed into the pits with a blanket of coke or anthracite filling the space between the anode blocks and the pit walls. A blanket of calcined petroleum coke fills the top of each pit, 25 to 30 cm (10-12 in) above the top layer of anodes.

The pits are heated with natural gas or oil fired manifolded burners for a period of about 40 hours. The flue system of the furnace is arranged so that hot gas from the pits being fired is drawn through the next section of pits to gradually preheat the next batch of anodes. The anodes are fired to approximately 1200°C (2200°F), and the cycle of placing green anodes, preheating, firing, cooling, and removal is approximately 28 days. The baked anodes are stripped from the furnace pits by means of an overhead crane which may also be used for loading and removing the coke pit packing.

The ring-type furnace flues are under draft. Most volatile hydrocarbon materials released from the anodes during the baking cycle are drawn into the flue with the combustion gases. These hydrocarbons burn and are a source of CO along with any CO formed as a result of incomplete fuel combustion.[72] Flue gases may be passed through scrubbers and perhaps electrostatic precipitators before exhausting to a stack. Typically, there are no special controls for CO removal.

After baking in a ring furnace, the baked anode blocks are moved to a rodding plant where steel stub electrodes are bonded into preformed holes in the blocks. Completed anode assemblies are delivered to the potlines, ready for the replacement of consumed anodes. Figure 7-26 shows a sectional view of a typical prebake reduction cell with a hood for cell effluent collection. The newer design prebake cells use up to twenty-six anode assemblies per cell.

The sacrificial carbon anodes are replaced periodically by new anode assemblies, the total operating time being dependent on the size of the anode blocks and the amperage of the potline.

7.6.1.2 Soderberg Cells

There are two types of Soderberg cells, each having a single large carbon anode, but differing in the method of anode bus connection to the anode mass. They are termed the horizontal spike suspension (HSS) Soderberg and the vertical spike suspension (VSS) Soderberg. The HSS Soderberg cells are being completely modified at all three operating plants. No information is available on the new process at this time. In both, the anode material is a paste of carbon and pitch which is fed periodically into the open top of a rectangular steel compartment and baked by the heat of the cell to a solid coherent mass as it moves down the casing. This casing is mounted on the steel superstructure of the cell and is raised or lowered by means of powered jacks. Paste is added to the upper section to replenish the anode as it is consumed. Figure 7-27 shows a schematic design of the HSS Soderberg cell design.

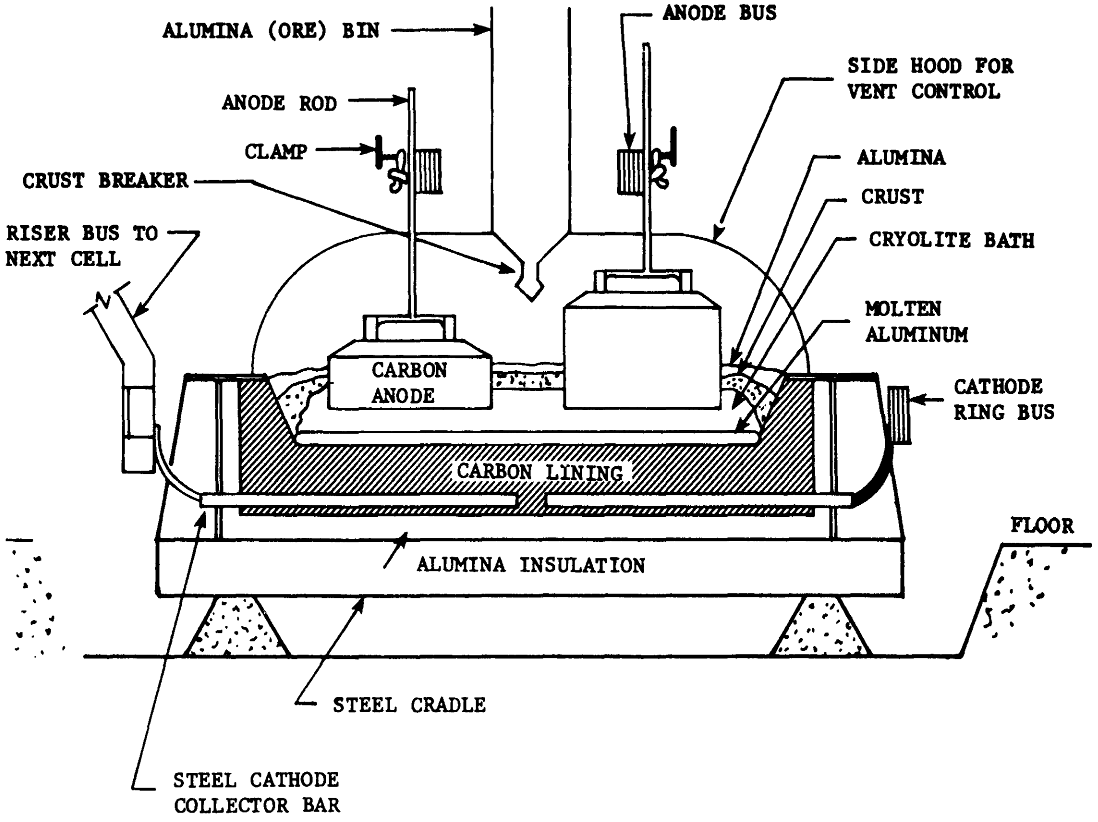


FIGURE 7-26. PREBAKE REDUCTION CELL, SCHEMATIC ARRANGEMENT

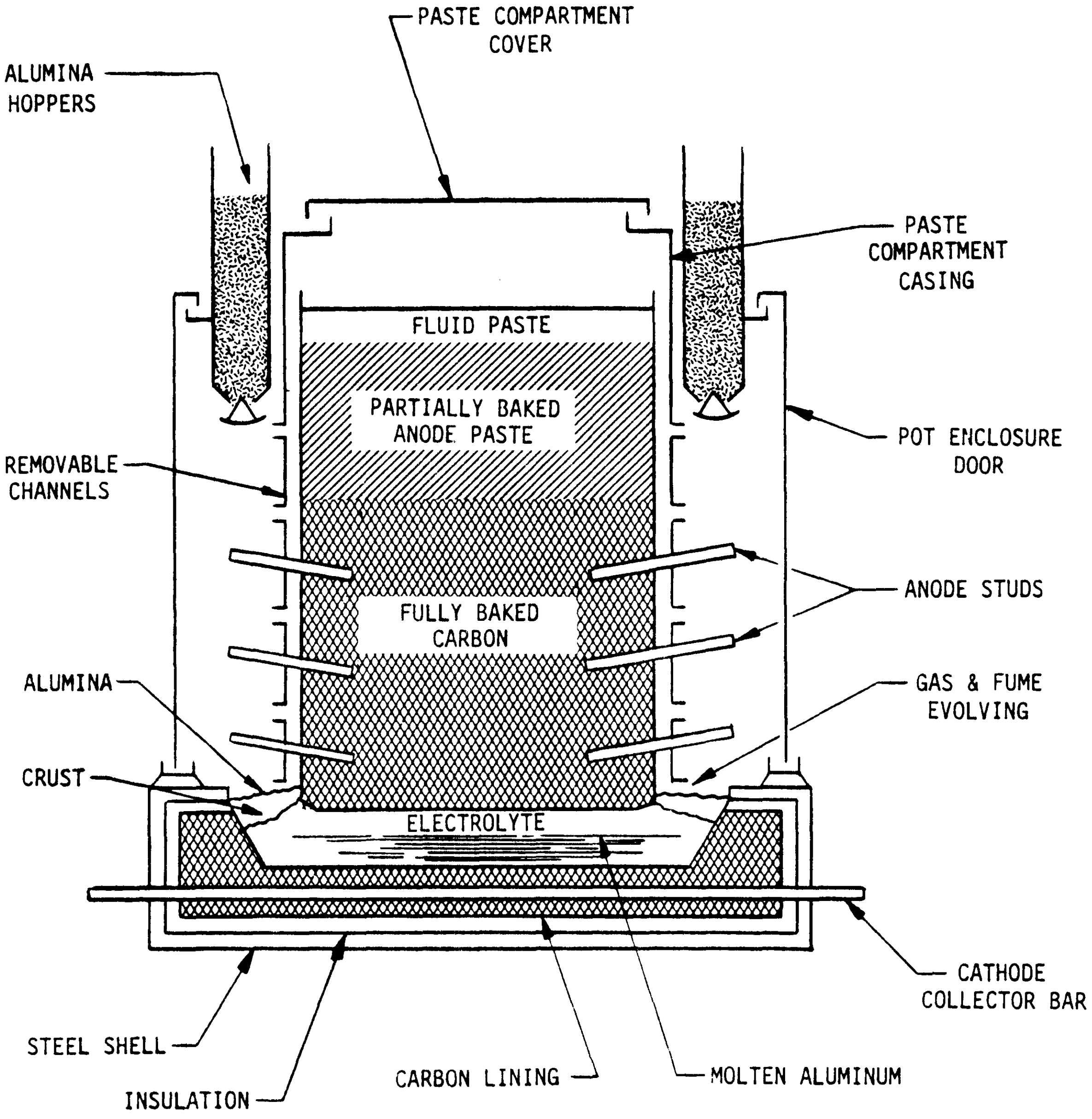


FIGURE 7-27. HSS SODERBERG CELL, SCHEMATIC ARRANGEMENT

In both types of Soderberg cells, CO, CO_2, and hydrocarbons are released as the pitch binder of the paste mixture bakes.[72] These products are a component of the Soderberg cell effluents and are essentially absent from those of the prebaked cells. Their tarry nature requires modification of the control treatment techniques applied to the effluents, as it interfers with pollutant removal devices. With HSS Soderberg cells hydrocarbons and CO are collected at the cell in a hood and exit in the primary off-gases.

7.6.2 Emission Sources and Factors

The three significant sources of emissions of CO in the primary aluminum industry as pointed out in the preceding section are:

1) the reaction of oxygen with carbon anodes during both types of cell operation,

2) baking of the pitch binder in Soderberg cell operation, and

3) baking of the anodes for the prebaked anode cells.

Emissions from the first two sources are found at the potlines; anode baking emissions occur in the baking furnace flue gases. In addition, there are miscellaneous sources of smaller amounts of CO emissions within aluminum plants (see Section 7.6.2.3). Limited data concerning emissions of CO from the primary aluminum industry are summarized in Table 7-26.

CO emissions from potlines, from anode baking furnaces, and from miscellaneous sources are quantified in the following discussion.

7.6.2.1 Potline Emissions

Little CO emission data are available for potline operations. Table 7-27 presents data on CO emissions collected by EPA while measuring fluoride emissions from several potline operations.[72] There are two emissions points from potlines: primary and secondary as shown in Figure 7-28. The reported primary CO emission rates for prebake cell potlines range from 250 to 960 kilograms CO per metric ton of aluminum produced (500 to 1900 lbs CO/ton Al).[72] No CO was detected in the primary outlet for either the VSS or HSS Soderberg cell plants.[72] The validity of these data is questionable.

Two types of secondary emissions were reported. CO emissions for one VSS plant were reported to be 340 kilograms CO per metric ton of aluminum produced (680 lbs CO/ton Al).[72] No CO was detected in the secondary outlet of two other plants (two measurements at one VSS plant, one measurement at an HSS plant).[72] The validity of these data is questionable.

TABLE 7-26

CARBON MONOXIDE EMISSIONS FROM PRIMARY ALUMINUM PRODUCTION

	CO EMISSIONS[a]	
PLANT TYPE	Metric Tons CO / yr	Tons CO / yr
Prebake anode	117,000	128,700
Horizontal stud Soderberg	57,900	63,700
Vertical stud Soderberg	28,400	31,200
Anode bake furnace	12,500	13,800
Other	3,600	4,000
TOTAL	219,400	241,400

---

[a] Based on 1973 production of 4,117,300 metric tons (4,529,000 tons) of aluminum.

Source: Reference 72

TABLE 7-27

AVERAGE POTLINE EMISSIONS[a]

Plant	Aluminum Production (metric tons/hr)	(tons/hr)	Gas Flow (dry) (Nm^3/s)	(SCFM)	CO Concentration (Volume %, dry)	CO Emission Rate (kg CO/metric ton Al)	(lb CO/ton Al)	Plant Type[b]
Primary outlet (controlled)								
A_1	0.465	0.512	2.5	5,100	0.0	0.0	0.0	VSS
A_2	0.469	0.516	2.2	4,600	0.0	0.0	0.0	VSS
B	0.401	0.441	23.1	48,800	0.0	0.0	0.0	HSS
C	0.112	0.123	4.8	10,200	0.6	960	2,000	PB
D	0.408	0.449	9.0	19,100	0.3	250	500	PB
D	0.408	0.449	9.4	20,000	0.3	260	510	PB
D	0.408	0.449	9.0	19,100	0.3	250	500	PB
Secondary outlet (controlled)								
A	0.233	0.256	65.7	139,000	0.027	340	690	VSS
A_1	0.233	0.256	119	252,000	0.0	0.0	0.0	VSS
A_2	0.235	0.258	121	257,000	0.0	0.0	0.0	VSS
B	2.40	2.64	1,330	2,810,000	0.0	0.0	0.0	HSS
Roof monitor (uncontrolled)								
C	3.36	3.70	1,110	2,360,000	0.0	0.0	0.0	PB
D	1.58	1.74	335	710,000	0.8	6,300	13,000	PB

---

[a] Data presented have not all been collected in the same fashion; Orsat analysis is the most common CO determination method used.

[b] VSS=vertical stud Soderberg; HSS=horizontal stud Soderberg; PB=prebaked anode.

Source: Reference 72

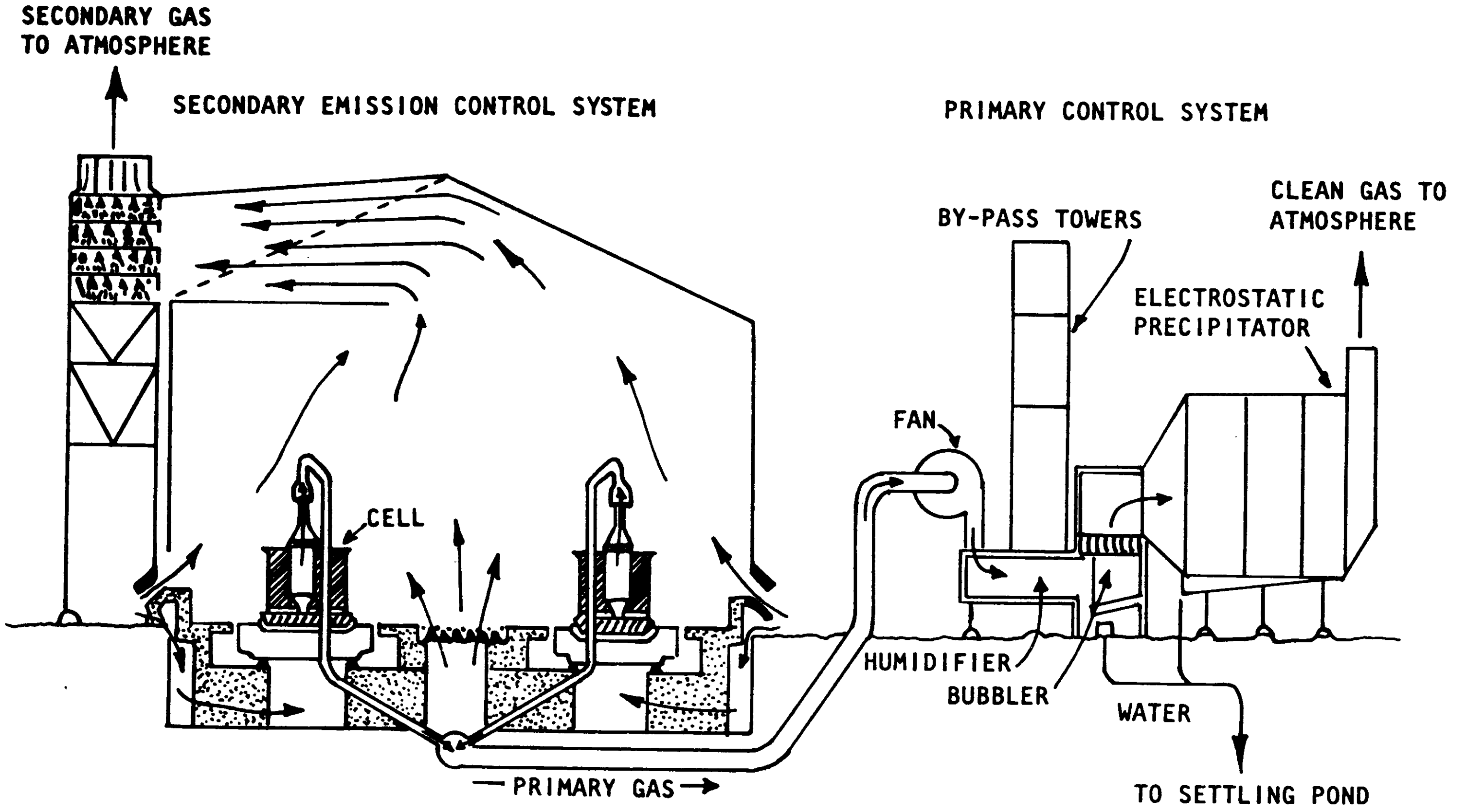


FIGURE 7-28. FLOW DIAGRAM FOR PRIMARY AND SECONDARY EMISSION CONTROL SYSTEMS

Two measurements were reported for prebake plants which had no controls on the roof monitor emissions.[72] In one case, no CO was detected in the roof monitor emissions.[72] For the other plant, CO emissions were reported to be 6,300 kilograms CO per metric ton of aluminum produced (12,600 lbs CO/ton Al).[72] The validity of these data is also questionable.

The foregoing data make it obvious that more study is needed to characterize primary and secondary CO emissions from both prebaked anode and Soderberg cell potlines.

7.6.2.2 Anode Bake Furnaces

CO emissions data for anode bake furnaces are also scarce. Table 7-28 presents data collected by EPA at one anode plant.[72] The CO emission factor for this plant ranged from 150 to 180 kilograms CO per metric ton (300 to 400 lb/ton) of anode produced. The average emission factor was 160 kilograms CO per metric ton (320 lb/ton) of anode produced.

TABLE 7-28

ANODE FURNACE CO EMISSIONS

PARAMETER	TEST NUMBER 1	2	3	AVERAGE
Anode production: kg/s	2.30	2.30	2.30	2.30
(lb/hr)	18,200	18,200	18,200	18,200
Gas flow (dry): Nm^3/s	18.3	21.1	17.5	18.6
(scfm)	40,000	45,000	37,000	40,000
CO concentration (Volume %, dry)	1.6	1.6	1.6	1.6
CO emission factor: kgCO/metric ton anode	160	180	150	160
(lb CO/ton anode)	320	360	300	320

Source: Reference 72

7.6.2.3 Miscellaneous Sources

Most aluminum reduction plants have a casthouse on-site. The casthouse usually has several reverberatory furnaces which are used for holding and fluxing the molten aluminum prior to casting. These furnaces are oil- or gas-fired and do emit small quantities of CO in the off-gases. All off-gases from the casthouse are vented uncontrolled to the atmosphere.

Prebake plants all have a rodding room associated with the carbon plant. In the rodding room, the copper rods which conduct electricity to the anode are fastened to the carbon anode with cast iron. The cast iron melting furnaces are small CO sources.

The only CO emission data from these sources were found in the 1973 National Emissions Data System (NEDS) file.[71] The total CO emissions reported were 3600 metric tons CO per year (4000 tons/yr). This translates to an emission factor of 0.88 kilograms CO per metric ton of aluminum (1.76 lb/ton Al) based on the 1973 U.S. primary aluminum production of 4,117,300 metric tons (4,529,000 tons) per year.[73] These emissions are small compared to those for anode bake furnaces and potlines.

7.6.3 Control Techniques

The primary aluminum industry does not presently use any techniques designed specifically for CO control. Should CO control become necessary, two control alternatives might be considered for primary emissions from the potlines. The first is thermal incineration of the CO present in the primary emissions in an afterburner. The second would be, in the case of prebake plants, recycle of the primary emissions to the anode bake furnace combustion air fan.

Low CO concentrations and huge gas volumes would make thermal or catalytic incineration of secondary CO emissions from potlines very costly.

Catalytic conversion of either the primary or secondary CO emissions might be impractical because of catalyst sensitivity to the particulate and gaseous fluorides present in the gas streams.

7.6.3.1 Thermal Incinerators

A thermal incinerator as described in Chapter 6 could possibly be used to combust CO present in the primary potline emissions. The incinerator would treat the gases after they exit either the wet or dry particulate removal devices used at most aluminum reduction plants. Supplemental fuel would be required to incinerate the primary potline emissions because of the low heating value of the gas [38 to 76 kilojoules/m^3 (1 to 2 Btu/ft^3)].[72]

An incinerator operating temperature between 870°C and 980°C (1600 to 1800°F) would be required to achieve adequate CO combustion efficiencies. Higher temperatures would result in more complete CO combustion but NO_x formation increases rapidly at temperatures above 980°C (1800°F). More study is needed to predict the effectiveness of thermal incineration for reducing low concentration CO emissions.

7.6.3.2 Potline Off Gas Recycle

At prebake anode reduction plants, it might be possible to duct the primary potline off-gases to the suction of the anode bake furnace combustion air fan. The duct length and fan size required would vary considerably from plant to plant. No supplemental fuel would be required other than the fuel currently used in the anode bake furnaces. Trace quantities of fluorides present in the gas stream pose a potential fan corrosion problem which should be investigated if this control option is considered.[72] More study is needed to predict the effectiveness and cost of this technique.

7.6.4 Cost of Controls

As mentioned earlier, the primary aluminum industry does not presently use any CO control technology. As a result, there are no cost data for either thermal incinerator or potline gas recycle installations at aluminum reduction plants. The size, layout, age, gas flow, and pot type all vary considerably between plants. Cost estimates would be very site specific. Furthermore, because of the sparse data on CO emission rates, it is not possible to calculate representative costs for CO control at this time.

7.6.5 Impact of Controls

7.6.5.1 Emissions Reduction

There are not enough data to estimate the potential effectiveness of thermal incineration for reducing CO emissions from primary aluminum plants.

7.6.5.2 Environment

If incineration were used to control CO emissions, NO_x emissions in the incinerator flue gas would increase. NO_x emissions increase as a function of temperature. Both the burner flame temperature and the average incinerator operating temperature affect the quantity of NO_x generated. Average incinerator temperatures of 980°C (1800°F) can be expected to cause significant quantities of NO_x to form.

At the present time, natural gas is generally used as supplemental incinerator fuel. If future shortages of natural gas necessitate the use of fuel oil as supplemental fuel, an increase in sulfur oxide emissions (SO_x) can be expected. The magnitude of the SO_x emissions would depend on the sulfur content of the fuel and the total amount of fuel consumed.

7.6.5.3 Energy Requirements

Because the potline off-gases have such a low heating value, only 38 to 76 kj/m^3 (1 to 2 Btu/ft^3), most of the heat for thermal incineration would have to be supplied by supplemental fuel.[72] Approximately 4 Nm^3 natural gas/Nm^3 off-gas (4 scf/scf) would be required to incinerate potline off-gases.[72] This represents between 46.3 and 220.1 megajoules/metric ton Al (40 to 190 x 10^3 Btu/ton Al), based on data from Reference 72.

7.7 PULP AND PAPER INDUSTRY

Although the pulp and paper industry is comprised of three distinct segments (pulp, primary paper and paperboard, and converted paper and paperboard products), the only segment which has the potential for contributing significant CO emissions to the atmosphere is the pulping segment. Furthermore, of the commercially used pulping processes, only one, the kraft process, is significant with respect to CO emissions. CO emissions from the kraft process were estimated by EPA at 1,105,700 metric tons/yr (1,218,700 tons/yr) in 1977.[2]

7.7.1 Process Description and Emission Factors

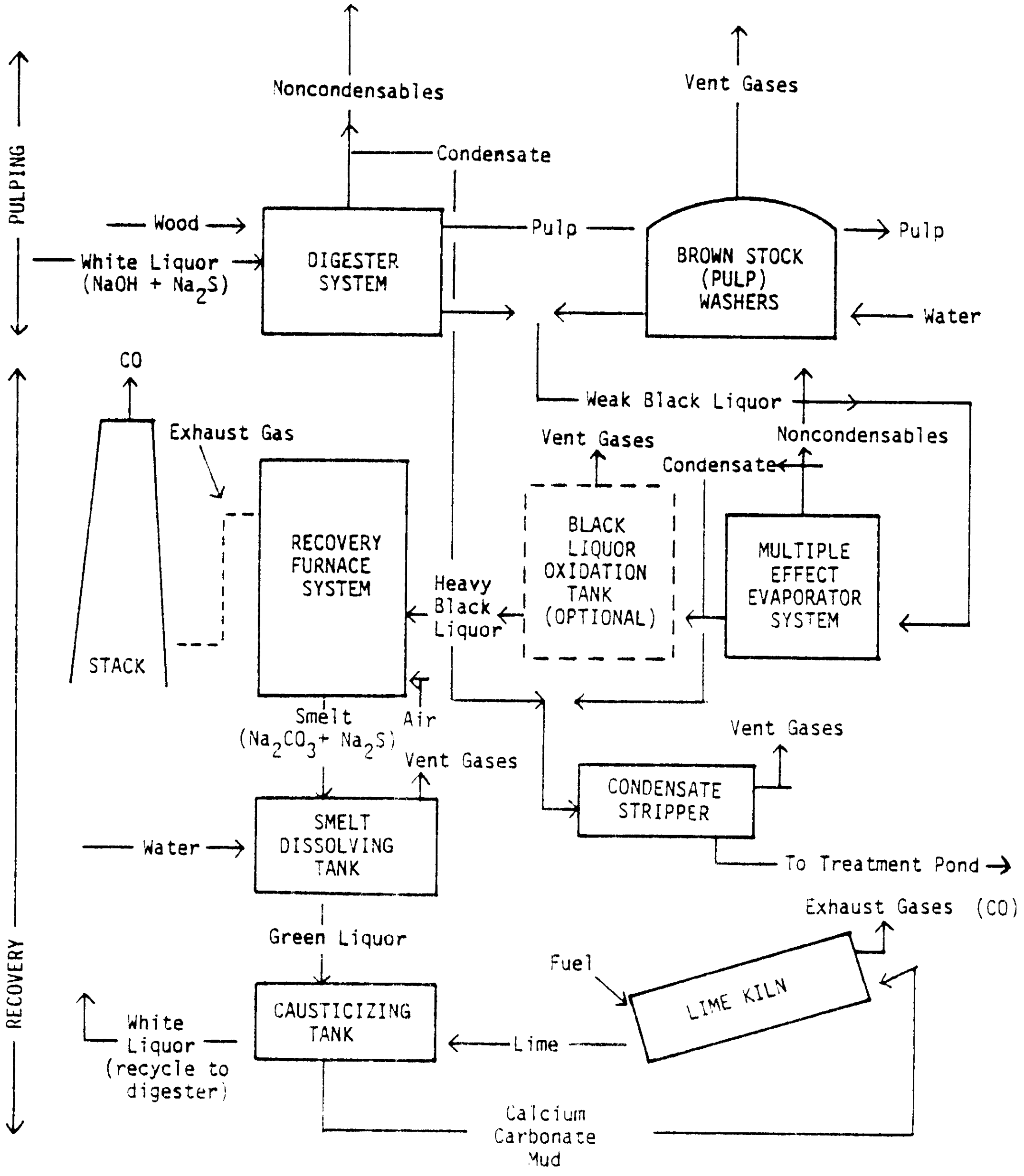
7.7.1.1 Process Description - Kraft Pulping

In the kraft or sulfate pulping process, cellulose fibers (i.e., pulp) are separated from the binding material called lignin. This is accomplished by chemical digestion at elevated temperature and pressure in a "white liquor" solution of sodium sulfide and sodium hydroxide. Then the pulp is separated by filtration, and the spent liquor, now referred to as "black liquor," is sent to a chemical recovery system along with pulp wash water. It is this recovery system which is the source of CO emissions of interest in this industry.

A simplified flow diagram of the kraft process is presented in Figure 7-29. The entire process may be considered in eight parts:

1. Digester
2. Brown stock washer system
3. Multiple-effect evaporation
4. Recovery furnace system
5. Smelt dissolving tank
6. Lime kiln
7. Black liquor oxidation system
8. Condensate stripping system

<u>Digestion</u> -- Digestion of the wood chips is carried out in batch, continuous or, in a few cases, rotary digestors. While usage of continuous units is increasing, most pulping at this time is still carried out in batch digestors. The wood chips are cooked with white liquor at about 170-175°C (340-350°F) and 0.8-1 megapascal (100-135 psig) for two to five hours. Gases formed during digestion are periodically vented to maintain proper process pressure. In batch processes, when the cooling is complete, the pressure is reduced to 0.7 megapascal (80 psig) and the contents are discharged to an atmospheric blow tank where the pulp is drained. The steam



Source: Reference 74

FIGURE 7-29. KRAFT PULPING AND RECOVERY PROCESS and other gases released here are sent to a heat accumulator recovery unit. This blow of the digestor does not pertain to continuous digestors.

Brown Stock Washer System -- Chunks of undigested wood are removed, and the remaining pulp is washed countercurrently in several stages. Vacuum filters are used to dewater the washed pulp.

Multiple-Effect Evaporators -- The brown stock wash water and spent liquor are combined to form a weak black liquor. This stream is concentrated from 12-18 percent solids to 40-55 percent solids in a series of five or six evaporation units. Further concentration steps may be taken to increase the solids content to 63 percent, which is the level needed for combustion in the recovery furnace.

Recovery Furnace System -- The concentrated black liquor from the evaporative system is then burned in the recovery furnace. Combustion in this manner allows for recovery of sodium and sulfur, production of steam, and disposal of unwanted dissolved wood components of the liquor. The furnace can theoretically be divided into three zones: drying, reducing and oxidizing. The black liquor is sprayed into the drying zone where evaporation takes place. The spray nozzles are located on one furnace wall and oscillate automatically so that the sheet spray covers the other walls. The frequency and extent of oscillation may be adjusted to optimize the operation and to minimize emission of objectionable gases. Emphasis is placed on minimizing reduced sulfur species, but CO emissions are also affected.

The solids fall to the hearth, forming the char bed where combustion begins. In the lower furnace (reduction) zone inorganic sulfate and other sodium compounds are reduced. These compounds, mainly sodium sulfide and sodium carbonate, settle out in a smelt on the furnace grate. Organic sulfur compounds are oxidized in the upper, or oxidizing zone. Combustion air is supplied by a forced-draft system through lower (primary) air ports in the reduction zone and through secondary and tertiary ports in the upper zone.

There are two types of furnaces in use. The majority in use at this time employ a direct contact evaporator to provide an evaporation step necessary for concentrating the 55 percent solids black liquor to 63-65 percent solids prior to combustion. In this type of furnace, black liquor is contacted directly with furnace exhaust gases. The other type is a noncontact, direct-fired, "low odor" or indirect-contact system.

Smelt Dissolving Tank -- This is a large tank located below the recovery furnace. Molten smelt discharged from the furnace floor is dissolved in water, forming "green liquor" in the stirred tank. A steam or liquid shatterjet system is used to break up the smelt stream before it contacts the water.

Lime Kiln -- This unit is a source of CO as well as particulate emissions. The kiln is a part of the closed-loop system that converts green liquor to white liquor. In the kiln calcination of the lime mud (calcium carbonate which precipitates in the causticizer) is carried out to produce calcium oxide for recausticizing the green liquor discharged from the smelt dissolving tank. Large rotary kilns with capacities of 36-360 megagrams (40-400 tons) of quicklime per day are typically used, although there are a few fluidized bed calciners also in use.[74] The lime sludge typically enters as a slurry containing 55-60 percent solids. The quicklime produced is then sent to a slaker to form a calcium hydroxide solution for the causticizing reaction.

Black Liquor Oxidation System -- The purpose of black liquor oxidation is to raise the oxidation state of sodium sulfide in either weak or strong black liquor, thereby decreasing reduced sulfur species emissions from the direct contact evaporator. Air, or in a few cases, oxygen is used to oxidize the sodium sulfide to sodium thiosulfate or a more oxidized form. The process can be carried out in sparging reactors, packed towers and bubble tray columns in single or multiple stages.

Condensate Stripping System -- Condensation of off-gases from the digestor and multiple-effect evaporators results in dissolution of some total reduced sulfur gases in the condensate. To avoid odor problems, these compounds are stripped either by air or steam before the condensates are discharged to the pond.

7.7.1.2 Emissions

In 1977, CO emissions from the kraft process were estimated at 1,105,700 metric tons (1,218,700 tons).[2] The major reported source of CO in this process is the sulfite recovery system. The conventional recovery system consists of a furnace and a direct-contact evaporator. Newer systems have, in some cases, a modified furnace and an indirect-contact evaporator. In the furnace, reduction of sulfate to sulfide takes place, with accompanying formation of reduced gaseous sulfur species and carbon monoxide. Air is admitted above this reduction zone to oxidize these combustible gases. If the furnace is operated within design capacity, CO emissions are very low. If furnaces are operated above their design capacity, there is an insufficient supply of air for complete combustion of the furnace gases, causing increased emissions of CO. Emissions of CO in the recovery furnace flue gas can vary from negligible under proper operation to nearly two volume percent with an inadequate air supply.[49] EPA emission factors range from 1-30 kg/metric ton (2-60 lb/ton), the higher number characterizing CO emissions from an overloaded furnace.[5] CO emissions measured by EPA from two recovery furnaces were about 1.3 kg/metric ton pulp (2.5 lb/ton).[74]

The quantity of carbon monoxide emitted from lime kilns depends upon the following factors:

1) kiln operating temperature,
2) amount of excess air, and
3) type of fuel used.

Table 7-29 presents reported compositions of exhaust gases from two rotary kilns of comparable throughput but operating at different temperatures and excess air levels. The type of fuel used in the kiln also affects the amount of CO emitted. When coal or coke are used, carbon monoxide concentrations in the exhaust gases may range up to one volume percent. For kilns using natural gas or fuel oil, CO concentrations are much less and may be negligible if the excess air and kiln operating temperature are high.

The reported CO emission factor from lime kilns is 5 kg/metric ton of air-dried unbleached pulp (10 lbs/ton).[5]

TABLE 7-29

REPORTED COMPOSITIONS OF EXHAUST GASES FROM TWO GAS-FIRED LIME SLUDGE KILNS

COMPONENT	VOLUME %	
	KILN A[a]	KILN B[b]
H_2O	37.1	30.0
CO_2	10.4	15.3
CO	0.0	0.5
O_2	3.2	0.2
N_2	49.3	54.0
	100.0	100.0

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[a] Kiln operated at very high excess air and exhaust temperature of 210°C (415°F).

[b] Kiln operated at less than 5% excess air and exhaust temperature of 175°C (350°F)

Source: Reference 42

7.7.2 Control Techniques

Currently there are not measures applied for CO control in the pulping industry. However, since the primary sources of CO emissions are recovery furnaces operating above design limits, the best control would simply be proper operation of these furnaces. As mentioned earlier, furnaces operating within design limits emit little or no carbon monoxide. Alternately, operation of furnaces above design capacity with low CO emissions may be possible with some modifications of furnace operation. Adjusting primary and secondary air rates to the furnace may provide the required amount of oxygen to oxidize the CO before it escapes. However, the effectiveness of this control method may be limited due to the decreased residence times of the gases in the furnace. CO concentrations in the off-gas will almost certainly depend upon this parameter. No data were available on this effect.

With increasingly strict regulation of total reduced sulfur emissions from the pulping industry, many plants are converting their recovery systems. These modifications usually include replacement of the furnace itself by one of more efficient design and/or conversion to an indirect-contact evaporator. These sulfur control measures should reduce total CO emissions.

The energy content of the exhaust gases from the recovery furnace is very low, less than 37 kilojoules/Nm^3 (1 Btu/scf).[42] For this reason, incineration of such a large volume, low energy content gas would be costly.

Lime kiln emissions of carbon monoxide can be most effectively controlled by operating the kiln at sufficient temperatures and excess air levels to eliminate the CO in the exhaust gases. However, the effectiveness of this technique on the CO from kilns fired with coke or coal is unknown. Based on the data reported in Table 7-29, high excess air levels and temperatures can reduce CO emissions from gas-fired kilns substantially (over 99 percent) compared to kilns operating with low excess air levels and lower temperatures.

7.7.3 Cost of Controls

Estimates for the costs of the controls outlined above are not available. Proper operation of these recovery furnaces operating above design limits should result in no additional costs. It may be argued, though, that this is in effect a derating of the furnace. Increasing primary and secondary air rates to the furnaces operating above design limits may require the addition of another blower to the furnace air supply system.

Costs for increasing excess air levels and temperatures in lime kilns will consist primarily of the cost for additional fuel to raise operating temperatures. Also, additional air supply capacity will need to be added to increase the excess air level in the lime kilns.

7.7.4 Impact of Controls

7.7.4.1 Emissions Reduction

Assuming that proper operation of recovery furnaces will result in one kg CO/metric ton pulp (2.0 lb/ton)[5] and applying this factor to total production (29 teragrams [32,000,000 tons] in 1974)[74] results in a total annual emission reduction of 29 gigagrams (32,000 tons CO) per year.

7.7.4.2 Energy Requirements

The additional fuel required to raise lime kiln operating temperatures will be the only significant energy requirement of the controls identified. No data were available to estimate this requirement.

7.7.4.3 Environment

No adverse environmental impacts are anticipated from modification of operating procedures for either recovery furnaces or lime kilns.

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12. SPONSORING AGENCY NAME AND ADDRESS DAA for Air Quality Planning and Standards Office of Air, Noise and Radiation U.S. Environmental Protection Agency Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED Final 14. SPONSORING AGENCY CODE EPA/200/04

15. SUPPLEMENTARY NOTES

This document is issued per the requirements of Section 108 of the Clean Air Ammendments of 1977.

16. ABSTRACT

Control Techniques for Carbon Monoxide Emissions presents recent developments of control techniques which have become available since preparation of the first edition of Control Techniques for Carbon Monoxide, Emissions from Stationary Sources (AP-65) and those sections of the first edition of Control Techniques for Carbon Monoxide Nitrogen Oxide, and Hydrocarbon Emissions from Mobile Sources (AP-66) that pertain to Carbon Monoxide. This edition presents available data on control techniques including description, effectiveness, costs, and energy and environmental aspects.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Carbon Monoxide Control Techniques Internal Combustion-Mobile Internal Combustion-Stationary Combustion Costs Industrial Sources		

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 411
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dhec
Healthy People. Healthy Communities.

December 27, 2017

Catherine Collins, USPHS
Bureau of Air & Water Resources
US Fish and Wildlife Service
7333 West Jefferson Ave., Suite 375, Lakewood, CO 80235

Re: Prevention of Significant Deterioration (PSD) Air Permit Application
BP Amoco Chemical Company - Cooper River Plant
Permit No. 0420-0029, Berkeley County

Dear Ms. Collins:

The Bureau of Air Quality (BAQ) received a PSD permit application from BP Amoco Chemical Company - Cooper River Plant, Wando, SC on December 14, 2017. The application was for the change in operation of equipment in the #1 OXidation Unit, to reduce operating costs. The completeness review period for the application officially began on this date and the application has been deemed technically complete as of December 20, 2017. It will now undergo technical review for a preliminary determination under the requirements of SC Regulation 61-62.5, Standard No. 7 (PSD).

An electronic copy of the PSD construction permit application is available for review upon your request. Please direct all written comments to my attention at the address below. If I can be of further assistance, please contact me at (803) 898-0660 or by E-mail at robinsjc@dhec.sc.gov.

Sincerely,

James C. Robinson, P.E.
Air Permitting Division
Bureau of Air Quality

cc: Permit File: 0420-0029
ec: Wendy Boswell, BEHS

Re: A few questions about the Cooper Rover plant application (0420-0029)

McAvoy, Bryan P.

Thu 1/4/2018 4:16 PM

To:rvandenmeiracker@trcsolutions.com <rvandenmeiracker@trcsolutions.com>;

Cc:Robinson, James C. <robinsjc@dhec.sc.gov>; Fox, David <DFox@trcsolutions.com>;

Robert,

Thank you for the timely reply. Greatly appreciated.

-Bryan @ DHEC.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Thursday, January 4, 2018 2:41:52 PM
To: McAvoy, Bryan P.
Cc: Robinson, James C.; Fox, David
Subject: RE: A few questions about the Cooper Rover plant application (0420-0029)

Bryan,

Thanks for connecting with me via email. I have answered your questions below in *italics*.

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: McAvoy, Bryan P. [mailto:mcavoybp@dhec.sc.gov]
Sent: Thursday, January 4, 2018 1:15 PM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Cc: Robinson, James C. <robinsjc@dhec.sc.gov>
Subject: A few questions about the Cooper Rover plant application (0420-0029)

Hello,

I am working on the modeling review part of the BP Amoco Cooper River Plant permit application. I have a couple questions about the submitted modeling.

1) The UTM's in Table 5-3 are different from what was run in AERMOD for the following four emission points: BT_702, BT_603, HPVGTS-1 and DT_302. *The coordinates in the most recent model are correct. The Table 5-3 values did not get updated.*

The UTM's in AERMOD match the modeling that was done in 2014. They also match what was submitted in DHEC form 2573. Therefore, I assume what's in AERMOD are the correct UTM's. However, I must verify this owing to the differences in the table. *The coordinates in the most recent model are correct. The Table 5-3 values did not get updated.*

2) The same applies to the base elevations of BT_702 and DT_302. *The table 5-3 values did not get updated.*

3) Your elevations are quite close to what I got out of AERMAP for the buildings and sources. But they are a tiny bit different. This isn't much of a problem. However, the report doesn't seem to clarify how the building and source locations were derived. I just need to verify whether you got them out of AERMAP, or if they were supplied by the facility. *Base elevations from AERMAP should be used.*

I've already run AERMOD on my end and the results are very close to yours. So none of this is stopping me from working on the modeling review. However, I will need a reply before I can submit the final report.

Bryan McAvoy
Meteorologist
S.C. Dept. of Health & Environmental Control
Office: (803) 898-1275
Email: mcavoybp@dhec.sc.gov
Connect: www.scdhec.gov

CO Material Balance Drawings

Andrews, Marianne <Marianne.Andrews2@bp.com>

Thu 1/11/2018 10:59 AM

To:Robinson, James C. <robinsjc@dhec.sc.gov>;

1 attachments (119 KB)

1236_001.pdf;

James,

Please see attached.

Thanks,
Marianne

CONFIDENTIAL

CO Material Balance Drawings

Andrews, Marianne <Marianne.Andrews2@bp.com>

Thu 1/11/2018 10:59 AM

To:Robinson, James C. <robinsjc@dhec.sc.gov>;

1 attachments (119 KB)

1236_001.pdf;

James,

Please see attached.

Thanks,
Marianne

Re: Discussion of Basis for CO Emissions from LPA (BT-603)

Robinson, James C.

Mon 2/12/2018 3:47 PM

Sent Items

To:Andrews, Marianne <Marianne.Andrews2@bp.com>;

You're welcome Marianne. I apologize, I had this email string in pinned emails box, and didn't realize you sent another email.

The permit clock, which is a very general gauge for when a permit will be issued, shows 109 days. If you're looking for something else, please let me know. Additionally, this is assuming that there are no other clock stoppages for more information.

From: Andrews, Marianne <Marianne.Andrews2@bp.com>
Sent: Monday, February 5, 2018 3:44:30 PM
To: Robinson, James C.
Subject: RE: Discussion of Basis for CO Emissions from LPA (BT-603)

Thanks, James. Let me know if you need anything else.

Also, I am being asked for an update on progress and timeline from my management. I know that a lot of the time since the official submission has been spent waiting on us to respond to your questions and comments. Can you give me any update on the timing/clock for this application, so I can update internally?

Marianne

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Monday, February 05, 2018 12:27 PM
To: Andrews, Marianne
Subject: Re: Discussion of Basis for CO Emissions from LPA (BT-603)

Thanks Marianne,

I'll take a look at it and let you know if I need anything else.

From: Andrews, Marianne <Marianne.Andrews2@bp.com>
Sent: Thursday, February 1, 2018 3:38:05 PM
To: Robinson, James C.
Subject: RE: Discussion of Basis for CO Emissions from LPA (BT-603)

James,

Please see the material balance and calculations attached.

I believe you also asked me about instrumentation/measurements when we talked earlier in January. I verified with the unit folks that the only instrumentation we have is on the combined vent stream out of the reactor. It is a Seimens IR CO/CO2 meter that we use for process control. This instrument's CO value was used in the attached calculations.

Also, regarding Henry's law, here is the response from our process engineering department:

The reactor 1st condenser runs both hotter and higher pressure than the other two condensers. There is a temperature drop and pressure drop as the flow goes through the condensers. The CO concentration is slightly lower in the 1st condenser liquid than it is in the other condenser liquids but the higher temperature is somewhat offset by the higher pressure in the 1st condenser. Because of the 1st crystallizer stream runs hotter than the other two the process requires the 1st condenser liquid stream flow to be higher than the 2nd and 3rd condenser flows which make the total CO flow higher. Sorry for the confusion.

I know it has taken a while to get back to you, but hopefully we have answered all the questions you and I discussed. Let me know if you have any other questions.

Thanks,
Marianne

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Thursday, January 11, 2018 4:00 PM
To: Andrews, Marianne
Subject: Discussion of Basis for CO Emissions from LPA (BT-603)

Marianne,

The second sentence in paragraph three of this discussion states "This stream runs hotter and therefore has more dissolved CO in the stream." This statement is not accurate according to Henry's gas law, as solubility of gases decreases with increasing temperature. This needs to be addressed or explained.

Additionally, provide a detailed conversion calculation showing how you come to 8 lb/hr of CO from the 1st condenser.

James C. Robinson, P.E.
Environmental Engineer
Air Permitting Division
Bureau of Air Quality
Office: (803) 898-0660
Connect: www.scdhec.gov Facebook Twitter

dhec
Healthy People. Healthy Communities.

FW: Discussion of Basis for CO Emissions from LPA (BT-603)

Andrews, Marianne <Marianne.Andrews2@bp.com>

Mon 2/19/2018 8:47 AM

To:Robinson, James C. <robinsjc@dhec.sc.gov>;

James,

Please see the response below from our process engineering group.

Regarding the return back into the reactor, that amount is not measured but is included in the total CO that vents to the HPVGTS.

Thanks,
Marianne

From: Childs, John F
Sent: Monday, February 19, 2018 8:08 AM
To: Andrews, Marianne
Subject: RE: Discussion of Basis for CO Emissions from LPA (BT-603)

Marianne,
Yes the estimated entrained gas volumetric flow was determined at the actual operating conditions and then converted to scfm. BP's uses 60° F and 14.7 psia as the basis for standard conditions.

We don't measure the amount of CO recycled to the reactor.

John Childs, PE
Sr. Process Engineer
843-800-3433 Lync
843-509-1243 Cell

Begin forwarded message:

> **From:** "Robinson, James C." <robinsjc@dhec.sc.gov>
> **Date:** February 14, 2018 at 3:56:32 PM EST
> **To:** "Andrews, Marianne" <Marianne.Andrews2@bp.com>
> **Subject: Re: Discussion of Basis for CO Emissions from LPA (BT-603)**
>
> Marianne,
>
> As a follow up to our phone conversation this afternoon, BP Amoco will need to verify if the entrained gas volumetric flow (cfm) in the 1st condenser stream was determined at actual operating conditions.

Additionally, on the process flow diagram, have the CO emission rates added to each condenser's return stream to the reactor. This will give me a better visual of what's happening with the CO. This information needs to be submitted by Wednesday, February 21, 2018.

Updated Table for RBLC

VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>

Tue 2/20/2018 5:40 PM

PSD Revision

To:Robinson, James C. <robinsjc@dhec.sc.gov>;

Cc:Andrews, Marianne <Marianne.Andrews2@bp.com>; Bailey, William <WBailey@trcsolutions.com>;

James,

The RBLC search was updated to include the ten year period that coincides with the Dragonslayer permit application RBLC search. The results of the search are included below. No controls were identified by this search that have not been previously identified. No applicable emission limits were identified.

Do you need any additional information?

Thanks,

Rob

PROCESS TYPE	RBLC ID	PROCESS	CO EMISSIONS LIMIT	CONTROL METHOD
64.003	ID-0017	Selexol Vent	8.7 lb/hr	Catox
	TX-0481	Rectisol Vent	11.4 lb/hr	NONE
		MSS Vent	21.64 lb/hr	NONE
	OH-0284	RTO Emissions	7.56 lb/hr	NONE
		TO Emissions	8.24 lb/hr	NONE
	TX-0354	TO Emissions- Steady State	9.56 lb/hr	NONE
64.999	TX-0609	Olefins Unit	146.43 tpy	Proper excess air and stream flow
	TX-0354	Incinerator	1.39 lb/hr	NONE
	TX-0675	N-10, Catalyst Regeneration	0	Good combustion practices
		N-11, Reactor Regeneration	0	Good combustion practices
		N-18, Decoking Drum	3360 lb	Good combustion practices
	TX-0624	Olefins Cracking	2256 tpy	Good engineering/combustion practices

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

Re: Updated Table for RBLC

Robinson, James C.

Thu 2/15/2018 2:04 PM

PSD Revision

To:rvandenmeiracker@trcsolutions.com <rvandenmeiracker@trcsolutions.com>;

`OK, I see. Thanks. OK on the update search dates.`

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Thursday, February 15, 2018 2:02:02 PM
To: Robinson, James C.
Subject: Updated Table for RBLC

This is how the Appendix C table should have looked.

I will update the table based the 10 years prior to the original application date.

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NA	FACILITY_S	PERMIT_NUM	SIC_CODE	NAICS_CODE	PERMIT_ISSU	PERMIT_T	FACILITY_DESCRIPTION	PERMIT_NOTES	PROCESS_NAME	PROCCESS_TYP	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_U	EMISSION_LIMIT_1_A	CASE-BY-C	OTHER_A	OTHER_FA	PERCENT_	EMISSION_	EMISSION_	EMISSION_	STANDAR	STANDARD	STANDARD	POLLUTANT_COMPLIANCE_NOTES
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	2869	325199	05/23/2014	B		Complete application date = date of administrative completeness This RBLC entry addresses the Ethylene Oxide/Monoethylene Glycol (EO/MEG) Unit of the Lake Charles Cracker Project.	E-222 Regenerator Condenser CO2 Vent (EQT 1010)	64.999		0			Carbon Monoxide	N		0.13	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATIN	U	0	0.34	TPY	ANNUAL M	0			
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	PSD-LA-761(M4)	2869	325199	12/22/2016	A	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	psd-la-761, issued 11/07/12, for relocation Unit I (3000 mt/yr) from punta arenas (chile); psd-la-761(M1), issued 07/12/13, for relocation Unit II (3000 mt/yr); psd-la-761(M2) (issued 01/15/16), psd-la-761(M3) (issued 01/14/16), and psd-la-761(M4) (issued 12/22/16) are for miscellaneous reconciliation	Compressor Vents (I-C-601, II-C-601)	64.999		11820	kg/hr		Carbon Monoxide	P	proper equipment design, good operating and maintenance practices	0			BACT-PSD		U	0	0			0			
TX-0609	OLEFINS PRODUCTION UNIT	EQUISTAR CHEMICALS, L.P.	TX	4682B/PSDTX761M2	2869	324110	02/10/2012	C	North and South Decoking Cyclones		Olefins Production Unit	64.999		0			Carbon Monoxide	P	Proper excess air and steam flow	146.43	T/YR		MACT		Y	0	0			0			
TX-0624	OP-2 UNIT	EQUISTAR CHEMICALS, LP	TX	2933/PSDTX1270/N140	2869	325110	11/14/2012	C	Olefins Cracking Unit	This project required PSD review for CO,NOx, PM/PM10/PM2.5 and a nonattainment review for VOC. The facility will also emit SO2, NH3 and H2S.	Olefins Cracking Unit	64.999	light hydrocarbons (e.g.,ethane,propane)	0		Construction of one additional olefins cracking furnace with dedicated SCR, a decoking pot, fugitive components in NH3 and VOC service, a compression and fractionation line, a group of process sampling analyzers, and MSS emissions for the proposed new equipment	Carbon Monoxide	P	good engineering/combustion practices	2256	T/YR		OTHER CA	NSPS , MA	N	0	0			0			
*TX-0652	MONT BELVIEU COMPLEX	ENTERPRISE PRODUCTS OPERATING LLC	TX	107523, PSDTX1336 AND N174	2869	33	03/13/2014	A	Propane Dehydrogenation (PDH) Unit		Propane Dehydrogenation to produce propylene	64.999	propane	1654	billion lbs/yr	This is a permit to construct a Propane Dehydrogenation (PDH) Unit. Air emissions will be from boilers, heaters, duct burners, air compressors, turbines, cooling tower, flare, storage vessels, fugitive components in VOC service, emergency engines, wastewater treatment system, and MSS emissions for the proposed new equipment	Carbon Monoxide	B	Good combustion practices, good design, catalytic oxidation and flare control	0			BACT-PSD	NSPS , NES	U	0	0			0			
*TX-0654	ETHYLENE UNIT	EQUISTAR CHEMICALS, L.P	TX	4682B/PSDTX761M3	2869	325110	04/16/2014	U	Olefins Plant		Ethylene Unit	64.999	ethane, propane, butane	4358	MMlb/yr	The plant is comprised of ethylene and gasoline hydro-treating units. The proposed changes will affect the ethylene unit, comprised of cracking furnaces, heaters,storage tanks, cooling towers, flare and numerous fugitive components in various liquid and gas services. The proposed expansion is primarily for increased firing rates at the furnaces and heaters, with revised tubing configurations in several of these sources to accommonade the increased rates. Proposed new equipment includes ultra lo-NOx burners in all the affected furnaces and components in VOC service. Also proposed are a new de-methanizer tower, a residue gas rectifier, an acetylene converter and new cells for the cooling tower.	Carbon Monoxide	P	good combustion practices. Emission factor for CO is proposed to be 0.035 lb CO/MMBtu fired which is equivalent to 50 ppmvd at 3%oxygen	0.035	LB/MMBTU		BACT-PSD	NSPS , MA	N	0	0			0			
*TX-0655	PROPANE DEHYDROGENATION PLANT	C3 PETROCHEMICALS, LLP	TX	107939/PSDTX1342/N176	2869	325110	04/21/2014	B	Chocolate Bayou		Propane Dehydrogenation to produce propylene	64.999	various light hydrocarbons	3500	MMlb/yr	The proposed facility will use propane as raw material in a dehydrogenation process to make industrial grade propylene. Primary process equipment and features include separator columns, reactors, compressors, separators, storage and cooling water and wastewater treatment. Prominent sources of air emissions include heaters, boilers, storage tanks, cooling towers, loading and emission capture facilities, a flare, analyzers, MSS and numerous fugitive components in various liquid and gas services.	Carbon Monoxide	P	Good engineering and combustion practices. CO emission factor of 0.035 (=50 ppmvd) is used in the calculation of CO from combustion sources	0.035	LB/MMBTU		BACT-PSD	NSPS , MA	U	0	0			0			

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NA	FACILITY_S	PERMIT_NUM	SIC_CODE	NAICS_CODE	PERMIT_ISSU	PERMIT_T	FACILITY_DESCRIPTION	PERMIT_NOTES	PROCESS_NAME	PROCCESS_TYP	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_U	EMISSION_LIMIT_1_A	CASE-BY-C	OTHER_A	OTHER_FA	PERCENT_	EMISSION_	EMISSION_	EMISSION_	STANDARA	STANDARI	STANDARI	POLLUTANT_COMPLIANCE_NOTES
TX-0675	ETHYLENE/PROPYLENE CRACKER AND COGENERATION FACILITY	BASF FINA PETROCHEMICALS LIMITED PARTNERSHIP	TX	36644	2869	325110	02/10/2010	C			N-10, Catalyst Regeneration Effluent	64.999		2050	cfs	Good combustion practices are used for EPN N-10.The catalyst from the Acetylene Converter main beds, Acetylene Converter Guard bed, Methyl Acetylene, Propadiene Converters, C4 Diolefin Hydrogenation Reactor and First Stage Diolefins Reactor is heated and any coke present on the catalyst is converted to CO or CO2. Since good combustion practices are good business practice, no additional conditions or monitoring were required for this amendment.	Carbon Monoxide	P	The decoking drum and furnace tubes are heated and any coke present on the catalyst is converted to CO or CO2. Unit used good combustion practices to meet BACT. Since good combustion practices are good business practice, no additional conditions or monitoring were required for this amendment.	0			BACT-PSD		U	0	0			0			
TX-0675	ETHYLENE/PROPYLENE CRACKER AND COGENERATION FACILITY	BASF FINA PETROCHEMICALS LIMITED PARTNERSHIP	TX	36644	2869	325110	02/10/2010	C			N-11, Reactor Regeneration Effluent	64.999		5064.83	cfm	The MSS process at N-11 is similar to N-10, the catalyst from the DP Reactor is heated and any coke present on the catalyst is converted to CO or CO2. Unit used good combustion practices to meet BACT Since good combustion practices are good business practice, no additional conditions or monitoring were required for this amendment.	Carbon Monoxide	P	The MSS process at N-11 is similar to N-10, the catalyst from the DP Reactor is heated and any coke present on the catalyst is converted to CO or CO2. Unit used good combustion practices to meet BACT Since good combustion practices are good business practice, no additional conditions or monitoring were required for this amendment.	0			BACT-PSD		U	0	0			0			
TX-0675	ETHYLENE/PROPYLENE CRACKER AND COGENERATION FACILITY	BASF FINA PETROCHEMICALS LIMITED PARTNERSHIP	TX	36644	2869	325110	02/10/2010	C			N-18, Decoking Drum	64.999		26625	coke/cycle	The decoking drum and furnace tubes are heated and any coke present on the catalyst is converted to CO or CO2. Unit used good combustion practices to meet BACT. Since good combustion practices are good business practice, no additional conditions or monitoring were required for this amendment.	Carbon Monoxide	P	The decoking drum and furnace tubes are heated and any coke present on the catalyst is converted to CO or CO2. Unit used good combustion practices to meet BACT. Since good combustion practices are good business practice, no additional conditions or monitoring were required for this amendment.	3360	POUND	HOUR	BACT-PSD		U	0	204.09	TON	YEAR	0			

BP Cooper River Common Cost Values for BACT Analysis

Robinson, James C.

Mon 2/26/2018 4:33 PM

Sent Items

To:rvandenmeiracker@trcsolutions.com <rvandenmeiracker@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>;

Rob,

These values should be the same as the ones used for the previous BACT Analysis. Resubmit the cost information with the corrected values. Once I've verified the numbers, you will need to submit hard copies of replacement pages for the public and confidential applications. The BACT analysis will need to be updated for each application as well.

James C. Robinson, P.E.
Environmental Engineer
Air Permitting Division
Bureau of Air Quality
Office: (803) 898-0660
Connect: www.scdhec.gov Facebook Twitter

Healthy People. Healthy Communities.

Re: Cost Analysis Spreadsheets

Robinson, James C.

Thu 3/8/2018 2:08 PM

PSD Revision

To:rvandenmeiracker@trcsolutions.com <rvandenmeiracker@trcsolutions.com>;

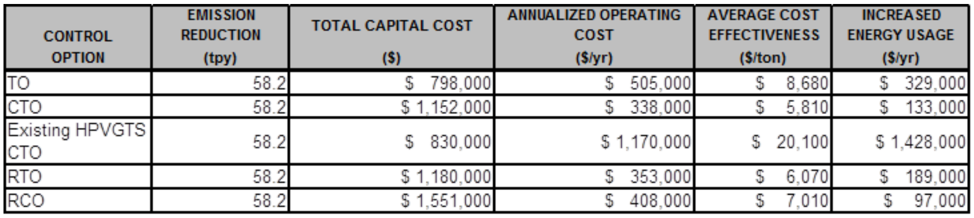
Cc:Andrews, Marianne <Marianne.Andrews2@bp.com>; Bailey, William <WBailey@trcsolutions.com>;

Thanks Rob, I will take a look and let you know.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Thursday, March 8, 2018 6:41:32 AM
To: Robinson, James C.
Cc: Andrews, Marianne; Bailey, William
Subject: RE: Cost Analysis Spreadsheets

James,

As requested, please find attached the updated cost information and the cost summary table from report below. If this is acceptable, we will update the BT-603 permit application.



CONTROL OPTION	EMISSION REDUCTION (tpy)	TOTAL CAPITAL COST ($)	ANNUALIZED OPERATING COST ($/yr)	AVERAGE COST EFFECTIVENESS ($/ton)	INCREASED ENERGY USAGE ($/yr)
TO	58.2	$ 798,000	$ 505,000	$ 8,680	$ 329,000
CTO	58.2	$ 1,152,000	$ 338,000	$ 5,810	$ 133,000
Existing HPVGTS CTO	58.2	$ 830,000	$ 1,170,000	$ 20,100	$ 1,428,000
RTO	58.2	$ 1,180,000	$ 353,000	$ 6,070	$ 189,000
RCO	58.2	$ 1,551,000	$ 408,000	$ 7,010	$ 97,000

Thanks,

Rob

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Wednesday, February 28, 2018 12:35 PM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>
Subject: Re: Cost Analysis Spreadsheets

You can send them after the updates.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Tuesday, February 27, 2018 4:22:28 PM
To: Robinson, James C.; Andrews, Marianne
Subject: RE: Cost Analysis Spreadsheets

OK, do you want them now, or once we update them with the costs from original Dragonslayer project?

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com

LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Tuesday, February 27, 2018 4:01 PM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>
Subject: Cost Analysis Spreadsheets

Rob, can you send me these spreadsheets. I'm trying to recreate some parts to check the numbers and I'm missing information (i.e. - hr/shift, shifts/day, days/yr, etc.). I may be overlooking something.

James C. Robinson, P.E.
Environmental Engineer
Air Permitting Division
Bureau of Air Quality
Office: (803) 898-0660
Connect: www.scdhec.gov Facebook Twitter

BP Cooper River

COMMON COST VALUES FOR BACT ANALYSIS

COST DESCRIPTION	COST	BASIS FOR COST
Operations and Maintenance Labor	45 $/hr	BP CR With Benefits
Natural Gas Cost	3.44 $/1,000 cf	BP CR
Electricity Cost	0.058 $/kW-hr	BP CR
Potable Water	2.67 $/1,000 gal	BP CR
Steam	5.80 $/1000 lb	BP CR
Nitrogen	1.625 $/1000 SCF	BP CR
Caustic	0.31 $/lb	BP CR
Capital Recovery Factor (8% and 20 year life)	0.10185	USEPA Financial References
Site Preparation	150,000	
Facilities and Buildings	25,000	

LPA CO COST TABLES
LPA DIRECT FIRE THERMAL OXIDIZER
BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs:			
Direct Fired Thermal Oxidizer (Input Cost: QAQPS USEPA Factor)		$255,000	
Ancillary Equipment		$38,250	N/A
Blower		$30,000	
Ancillary Equipment		$4,500	
		Sum = "A" =	*$327,750*
Instrumentation (0.10 * A)		$32,775	
Sales Taxes (0.03 * A)		$9,833	
Freight (0.05 * A)		$16,388	
	Purchased Equipment Cost = "B" =		*$386,745*
Direst Installation Costs			
Foundation and Supports (0.08 * B)		$30,940	
Handling and Errection (0.14 * B)		$54,144	
Electrical (0.04 * B)		$15,470	
Piping, Ductwork, and Installation (0.02 *B)		$7,735	
Insulation for Ductwork (0.01 * B)		$3,867	
Painting (0.01 * B)		$3,867	
	Direct Installation Cost =		*$116,024*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$677,769*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$38,675	
Construction and Field Expenses (0.05 *B)		$19,337	
Contractor Fees (0.10 *B)		$38,675	
Start-Up (0.02 *B)		$7,735	
Performance Test (0.01 *B)		$3,867	
Contingencies (0.03 * B)		$11,602	
	Total Indirect Cost =		*$119,891*
	TOTAL CAPITAL INVESTMENT =		**$797,659**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$32,850
Supervisor	= (15% of Operator Cost)		$4,928
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$5,475
Maintenance Materials	= 100% of Maintenance Labor		$5,475
Replacement Labor	N/A		$0
Parts Cost	N/A		$0
Utilities:			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	165.0	$298,331
Electricity	= $/kWhr*hp*1 kWhr/1.341 hp*8760 hr/yr	40.5	$15,345
		Total DC =	*$362,403*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$48,728	$29,237
Administrative	= 2% of Total Capital Investment		$15,953
Property Tax	= 1% of Total Capital Investment		$7,977
Insurance	= 1% of Total Capital Investment		$7,977
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$81,242
		Total IC =	*$142,384*
	TOTAL ANNUAL OPERATING COSTS =		**$504,787**

LPA CATALYTIC THERMAL OXIDIZER (New)
BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs:			
Catalytic Thermal Oxidizer (User Input Cost: QAQPS USEPA Factor)		$ 417,000	
Ancillary Equipment		$62,550	N/A
Blower		$30,000	
Ancillary Equipment		$4,500	
		Sum = "A" =	*$ 514,050.00*
Instrumentation (0.10 * A)		$51,405	
Sales Taxes (0.03 * A)		$15,422	
Freight (0.05 * A)		$25,703	
	Purchased Equipment Cost = "B" =		*$606,579*
Direst Installation Costs			
Foundation and Supports (0.08 * B)		$48,526	
Handling and Errection (0.14 * B)		$84,921	
Electrical (0.04 * B)		$24,263	
Piping, Ductwork, and Installation (0.02 *B)		$12,132	
Insulation for Ductwork (0.01 * B)		$6,066	
Painting (0.01 * B)		$6,066	
	Direct Installation Cost =		*$181,974*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$963,553*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$60,658	
Construction and Field Expenses (0.05 *B)		$30,329	
Contractor Fees (0.10 *B)		$60,658	
Start-Up (0.02 *B)		$12,132	
Performance Test (0.01 *B)		$6,066	
Contingencies (0.03 * B)		$18,197	
	Total Indirect Cost =		*$188,039*
	TOTAL CAPITAL INVESTMENT =		**$1,151,592**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$14,600
Supervisor	= (15% of Operator Cost)		$2,190
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$14,600
Maintenance Materials	= 100% of Maintenance Labor		$14,600
Replacement Labor	N/A		$0
Catalyst Cost	= CF cat* $850/CF* 1@5 years	25	$4,250
Utilities:			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	45.0	$81,363
Electricity	= $/kWhr*hp*1 kWhr/1.341 hp*8760 hr/yr	40.5	$15,345
		Total DC =	*$146,948*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$45,990	$27,594
Administrative	= 2% of Total Capital Investment		$23,032
Property Tax	= 1% of Total Capital Investment		$11,516
Insurance	= 1% of Total Capital Investment		$11,516
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$117,290
		Total IC =	*$190,947*
	TOTAL ANNUAL OPERATING COSTS =		**$337,895**

LPA TO EXISTING CATALYTIC THERMAL OXIDIZER ON HPA
BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs: Existing Unit			
Catalytic Thermal Oxidizer (User Input Cost: QAQPS USEPA Factor)		$0	
Ancillary Equipment		$0	
Compressor		$300,000	
Ancillary Equipment		$45,000	
		Sum = "A" =	*$345,000*
Instrumentation (0.10 * A)		$34,500	
Sales Taxes (0.03 * A)		$10,350	
Freight (0.05 * A)		$17,250	
	Purchased Equipment Cost = "B" =		*$407,100*
Direst Installation Costs			
Foundation and Supports (0.08 * B)		$32,568	
Handling and Errection (0.14 * B)		$56,994	
Electrical (0.04 * B)		$16,284	
Piping, Ductwork, and Installation (0.02 *B)		$8,142	
Insulation for Ductwork (0.01 * B)		$4,071	
Painting (0.01 * B)		$4,071	
	Direct Installation Cost =		*$122,130*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$704,230*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$40,710	
Construction and Field Expenses (0.05 *B)		$20,355	
Contractor Fees (0.10 *B)		$40,710	
Start-Up (0.02 *B)		$8,142	
Performance Test (0.01 *B)		$4,071	
Contingencies (0.03 * B)		$12,213	
	Total Indirect Cost =		*$126,201*
	TOTAL CAPITAL INVESTMENT =		**$830,431**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Supervisor	= (15% of Operator Cost)		$2,464
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	3	$98,550
Maintenance Materials	= 100% of Maintenance Labor		$98,550
Replacement Labor	N/A		$0
Catalyst Cost	= CF cat* $850/CF* 1@5 years	478	$81,260
Utilities:			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	65.0	$117,524
Electricity	= $/kWhr*hp*1 kWhr/1.341 hp*8760 hr/yr	1341.0	$508,080
		Total DC =	*$922,853*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$215,989	$129,593
Administrative	= 2% of Total Capital Investment		$16,609
Property Tax	= 1% of Total Capital Investment		$8,304
Insurance	= 1% of Total Capital Investment		$8,304
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$84,579
		Total IC =	*$247,390*
	TOTAL ANNUAL OPERATING COSTS =		**$1,170,243**

LPA REGENERATIVE THERMAL OXIDIZER
BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs			
Regenerative Thermal Oxidizer (User Input Cost: QAQPS USEPA Factor)		$430,000	
Ancillary Equipment		$64,500	N/A
Blower		$30,000	
Ancillary Equipment		$4,500	
		Sum = "A" =	*529,000*
Instrumentation (0.10 * A)		$52,900	
Sales Taxes (0.03 * A)		$15,870	6
Freight (0.05 * A)		$26,450	
	Purchased Equipment Cost = "B" =		*$624,220*
Direst Installation Costs			
Foundation and Supports (0.08 * B)		$49,938	
Handling and Errection (0.14 * B)		$87,391	
Electrical (0.04 * B)		$24,969	
Piping, Ductwork, and Installation (0.02 *B)		$12,484	
Insulation for Ductwork (0.01 * B)		$6,242	
Painting (0.01 * B)		$6,242	
	Direct Installation Cost =		*$187,266*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$986,486*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$62,422	
Construction and Field Expenses (0.05 *B)		$31,211	
Contractor Fees (0.10 *B)		$62,422	
Start-Up (0.02 *B)		$12,484	
Performance Test (0.01 *B)		$6,242	
Contingencies (0.03 * B)		$18,727	
	Total Indirect Cost =		*$193,508*
	TOTAL CAPITAL INVESTMENT =		**$1,179,994**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Supervisor	= (15% of Operator Cost)		$2,464
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Maintenance Materials	= 100% of Maintenance Labor		$16,425
Replacement Labor	N/A		$0
Parts Cost	N/A		$0
Utilities:			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	40.0	$72,323
Electricity	= $/kWhr* kWhr *8760 hr/yr	40.0	$20,323
Media Replacement	= CF media * $50/CF / 2 years	400.0	$10,000
		Total DC =	*$154,385*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$51,739	$31,043
Administrative	= 2% of Total Capital Investment		$23,600
Property Tax	= 1% of Total Capital Investment		$11,800
Insurance	= 1% of Total Capital Investment		$11,800
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$120,182
		Total IC =	*$198,425*
	TOTAL ANNUAL OPERATING COSTS =		**$352,810**

LPA RECUPERATIVE THERMAL OXIDIZER
BASIS: OAQPS Cost Manual (Sixth Edition)

COST ITEM		COST	TOTALS
Direct Costs			
Purchased Equipment Costs:			
Recuperative Thermal Oxidizer (User Input Cost: QAQPS USEPA Factor)		$600,000	
Ancillary Equipment		$90,000	
Blower		$30,000	
Ancillary Equipment		$4,500	
		Sum = "A" =	*$724,500*
Instrumentation (0.10 * A)		$72,450	
Sales Taxes (0.03 * A)		$21,735	
Freight (0.05 * A)		$36,225	
	Purchased Equipment Cost = "B" =		*$854,910*
Direst Installation Costs			
Foundation and Supports (0.08 * B)		$68,393	
Handling and Errection (0.14 * B)		$119,687	
Electrical (0.04 * B)		$34,196	
Piping, Ductwork, and Installation (0.02 *B)		$17,098	
Insulation for Ductwork (0.01 * B)		$8,549	
Painting (0.01 * B)		$8,549	
	Direct Installation Cost =		*$256,473*
Site Preparation (User Inputs Actual Cost)		$150,000	
Facilities and Buildings (User Inputs Actual Cost)		$25,000	
	Total Direct Cost =		*$1,286,383*
Indirect Cost (Installation)			
Engineering (0.10 * B)		$85,491	
Construction and Field Expenses (0.05 *B)		$42,746	
Contractor Fees (0.10 *B)		$85,491	
Start-Up (0.02 *B)		$17,098	
Performance Test (0.01 *B)		$8,549	
Contingencies (0.03 * B)		$25,647	
	Total Indirect Cost =		*$265,022*
TOTAL CAPITAL INVESTMENT =			**$1,551,405**
Direct Annual Costs (DC)			
Operating Labor	***(Basis of Calculations)***		
Operator	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Supervisor	= (15% of Operator Cost)		$2,464
Operating Materials	(If Any)		$0
Maintenance Labor	= (hr/shift * shifts/day * days/yr * $/hr)	0.5	$16,425
Maintenance Materials	= 100% of Maintenance Labor		$16,425
Replacement Labor	N/A		$0
Parts Cost	N/A		$0
Utilities:			
Fuel (natural gas)	(cfm/1000 * $/1000 cf * 60 min/hr *8760 hr/yr)	50.0	$90,403
Electricity	= $/kWhr*hp*1 kWhr/1.341 hp*8760 hr/yr	40.0	$15,155
		Total DC =	*$157,297*
Indirect Annual Costs (IC)			
Overhead	= 60% of the Sum of Total Labor + Materials	$51,739	$31,043
Administrative	= 2% of Total Capital Investment		$31,028
Property Tax	= 1% of Total Capital Investment		$15,514
Insurance	= 1% of Total Capital Investment		$15,514
Capital Recovery	(Based on 8% & 20 year life: Factor = 0.10185)		$158,011
		Total IC =	*$251,110*
TOTAL ANNUAL OPERATING COSTS =			**$408,407**

RE: Cost Analysis Spreadsheets

VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>

Mon 4/9/2018 10:18 AM

To:Robinson, James C. <robinsjc@dhec.sc.gov>;

Right.

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Monday, April 9, 2018 10:11 AM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Subject: Re: Cost Analysis Spreadsheets

Rob,

As a reminder, all numbers should be based the previous permit's dates/time frames, unless it gives a more conservative output.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Monday, April 9, 2018 7:49:12 AM
To: Robinson, James C.
Subject: RE: Cost Analysis Spreadsheets

Yes, the $/scf and $/kw values changed so the total cost will change.

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

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rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Monday, April 9, 2018 7:40 AM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Subject: Re: Cost Analysis Spreadsheets

Rob, would the energy cost change? If so, how or why would it?

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Monday, April 9, 2018 6:40:04 AM
To: Robinson, James C.
Subject: RE: Cost Analysis Spreadsheets

James,

Though we changed the $/ton figures in the table, the increased energy costs were not updated. I will do this later today and send you an update.

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Friday, April 6, 2018 11:44 AM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Subject: Re: Cost Analysis Spreadsheets

Rob, how did you come up with the increased energy usage numbers in the BACT Analysis Table?

Table 4-5
LPA CO BACT Analysis

CONTROL OPTION	EMISSION REDUCTION (tpy)	TOTAL CAPITAL COST ($)	ANNUALIZED OPERATING COST ($)	AVERAGE COST EFFECTIVENESS ($/ton)	INCREASED ENERGY USAGE ($/yr)	ADVERSE ENVIRONMENTAL IMPACTS?
DFTO	58.2	$ 798,000	$ 505,000	$ 8,680	$ 314,000	Yes
CTO	58.2	$ 1,152,000	$ 338,000	$ 5,810	$ 97,000	Yes
Existing HPVGTS CTO	58.2	$ 830,000	$ 1,170,000	$ 20,100	$ 626,000	Yes
RTO	58.2	$ 1,180,000	$ 353,000	$ 6,070	$ 93,000	Yes
RO	58.2	$ 1,551,000	$ 408,000	$ 7,010	$ 106,000	Yes

RE: Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>

Thu 4/19/2018 5:35 PM

To:Robinson, James C. <robinsjc@dhec.sc.gov>;

Cc:Bailey, William <WBailey@trcsolutions.com>; Van Valkinburgh, Kathryn <kvanvalkinburgh@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>;

3 attachments (946 KB)

0420-0029cu.r1 draft 1.docx; 0420-0029cu.r1.sob draft 1.docx; 0420-0029cu.pd.r1 draft 1 - Copy.doc;

James,

A few minor edits in the attached. Very good work. We appreciate your efforts on this revision.

Thanks,

Rob

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Thursday, April 12, 2018 2:17 PM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>
Subject: Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Please review the following draft documents and provide comments by COB, Thursday, April 19. Note that the documents are in track changes. I am also having a formatting issue with the preliminary determination; however, I will be working on it while the drafts are being reviewed.

James C. Robinson, P.E.
Environmental Engineer
Air Permitting Division
Bureau of Air Quality
Office: (803) 898-0660
Connect: www.scdhec.gov Facebook Twitter
http://www.scdhec.gov/images/logo_email.jpg

Bureau of Air Quality
Prevention of Significant Deterioration
Preliminary Determination

BP Amoco Chemical Company – Cooper River Plant

Wando, South Carolina
Berkeley County

Permit No. 0420-0029-CU.R1
DATE??

This review was performed by the Bureau of Air Quality of the South Carolina Department of Health and Environmental Control in accordance with South Carolina Regulations for the Prevention of Significant Air Quality Deterioration.

Modeling Analysis Reviewed by:	**Modeling Analysis Approved by:**
Bryan P. McAvoy Modeler Bureau of Air Quality	John Glass, Manager Modeling Section Bureau of Air Quality
Reviewed by:	**Approved by:**
James C. Robinson, P.E. Environmental Engineer Bureau of Air Quality	Steve McCaslin, P. E., Director Air Permitting Division Bureau of Air Quality

South Carolina

Department of Health and Environmental Control

Bureau of Air Quality

Preliminary Determination

For

BP Amoco Chemical Company – Cooper River Plant
Wando, Berkeley County, South Carolina

October 8, 2014

Preliminary Determination

This review was performed by the Bureau of Air Quality of the South Carolina Department of Health and Environmental Control in accordance with South Carolina Regulations for the Prevention of Significant Air Quality Deterioration.

October 8, 2014

Modeling Analysis Reviewed by: ________________________________
Tracy O. Price
Modeling Section
Bureau of Air Quality

Modeling Analysis Approved by: ________________________________
John Glass, Manager
Modeling Section
Bureau of Air Quality

Reviewed by: ________________________________
James C. Robinson, P.E.
Environmental Engineer
Bureau of Air Quality

Approved by: ________________________________
Elizabeth J. Basil, Director
Engineering Services Division
Bureau of Air Quality

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Appendices

I. Time Line (Permitting Action History)

June 21, 2012	Representatives of BP Amoco Chemical Company - Cooper River Plant (BPCR) and TRC Environmental Corporation (TRC) met with the South Carolina Department of Health and Environmental Control Bureau of Air Quality (BAQ) personnel to discuss a proposed expedited Prevention of Significant Deterioration (PSD) construction permit application for a major plant modernization/debottleneck project.
March 20, 2013	Representatives of BPCR and TRC met with SCDHEC personnel for a second time to discuss the draft expedited PSD construction permit application, and how does the addition of two new cooling tower cells relate to the propose PSD project.
April 11, 2013	TRC, on behalf of BPCR, submitted an expedited PSD construction permit application to SCDHEC proposing to modernize and debottleneck the plant at BPCR located in Wando, South Carolina.
April 18, 2013	SCDHEC notified BPCR and TRC via email and phone that SCDHEC accepted the PSD construction permit application into the expedited program.
April 19, 2013	Engineering Services of BAQ e-mailed a copy of the application to Catherine Collins (US Fish and Wildlife Services) and Heather Ceron (US EPA – Region IV) and informed them that BAQ had deemed the application complete.
April 22, 2013	BAQ Permitting issues letter to BPCR to request additional information and clarify items in the application. Facility was given a May 6, 2013 deadline to provide requested information.
April 26, 2013	Tracy Price of SCDHEC sends email to BPCR to request additional information and clarify items regarding the modeling portions of the application.
April 26, 2013	BPCR sent email to James Robinson and Tracy Price requesting a meeting to discuss the information requested by SCDHEC.
May 2, 2013	BPCR and TRC met with SCDHEC at 2600 Bull St., Conference Room 2290, to discuss the information requested by SCDHEC.

May 8, 2013	TRC, on behalf of BPCR, submitted the information as requested by SCDHEC on April 26, 2013.
May 9, 2013	Air Quality Modeling Section (Modeling) sent email to BPCR and TRC requesting additional information on modeling items.
May 9, 2013	TRC, on behalf of BPCR, emailed additional information as requested by Modeling on May 9, 2013.
May 13, 2013	TRC, on behalf of BPCR, submitted additional information as requested by SCDHEC (James Robinson) on April 26, 2013.
May 15, 2013	Modeling sent email to BPCR and TRC requesting additional information and clarification on modeling items.
May 21, 2013	TRC, on behalf of BPCR, emailed additional information as requested by SCDHEC Modeling on May 15, 2013.
May 21, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed PSD project updates via phone call.
June 6, 2013	SCDHEC personnel held conference call with BPCR and TRC to discuss PSD netting analysis. BAQ requested that BPCR submit a proper netting analysis of PSD project.
June 12, 2013	SCDHEC personnel held conference call with BPCR and TRC to discuss additional information (control device descriptions, more detailed process and proposed changes descriptions, detail discussion synthetic minor/PSD avoidance limits, reduction in VOC emissions in Wastewater Treatment Area) needed for the PSD application.
June 12, 2013	SCDHEC personnel held conference call with EPA personnel (Katie Lusky) to discuss PSD netting analysis for BPCR PSD project.

June 14, 2013	Brent Pace of BPCR and James Robinson of SCDHEC held follow up phone call for clarification on June 12, 2013 phone call.
June 18, 2013	BAQ Permitting sent email to BPCR and TRC requesting additional information on PSD netting analysis, significant emissions increases, and other items needed for the Preliminary Determination.
June 20, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed PSD project updates via phone call.
June 25, 2013	James Robinson held conference call with BPCR and TRC to discuss additional information on PSD netting analysis, significant emissions increases, and other items needed for the Preliminary Determination. BPCR proposes to submit a revised PSD application.
June 26, 2013	Brent Pace of BPCR and James Robinson of SCDHEC held follow up phone call for clarification on June 25, 2013 phone call.
July 2, 2013	Brent Pace of BPCR requested a one week extension to submit a revised application, to July 12, 2013. James Robinson of SCDHEC granted one week extension.
July 10, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed clarification of PSD emissions calculations via phone call. Mr. Pace requested an additional one week extension to submit a revised application, to July 19, 2013. Mr. Robinson of SCDHEC granted additional one week extension.
July 19, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed PSD updates. Mr. Pace requested an additional two week extension to submit a revised application, to August 2, 2013. Mr. Robinson of SCDHEC granted additional two week extension.
August 2, 2013	Brent Pace of BPCR and James Robinson of SCDHEC discussed PSD updates. Mr. Pace requested to put project on hold for at least three weeks, in order to decide next steps forward. Mr. Robinson of SCDHEC acknowledged hold request.
September 7, 2013	After a few email exchanges between August 2, 2013 and September 7, 2013 discussing the status of revised application, Brent Pace of BPCR and James Robinson of SCDHEC agreed that Brent Pace will notify James Robinson when BPCR is close to submitting a revised application.
December 17, 2013	Brent Pace of BPCR emailed James Robinson of SCDHEC some pages of the draft revised application to review.

January 10, 2014	James Robinson of SCDHEC emailed comments on pages of draft revised application to Brent Pace of BPCR.
January 20, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC responses to comments.
January 24, 2014	Brent Pace of BPCR and James Robinson of SCDHEC discussed responses to comments on pages of draft revised application.
March 11, 2014	TRC, on behalf of BPCR, submitted a revised expedited PSD construction permit application to SCDHEC.
March 14, 2014	James Robinson of SCDHEC emailed Natasha Hazziez of EPA Region 4 an electronic copy of the revised PSD application.
March 17, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR to request additional information and clarify items in the revised application.
April 3, 2014	Brent Pace of BPCR and James Robinson of SCDHEC discussed March 17, 2014 request for additional information to clarify items in the revised application.
April 9, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC some responses to March 17, 2014 request. BPCR need to send updates and replacement pages to the revised application.
April 14, 2014	James Robinson of SCDHEC emailed Natasha Hazziez of EPA Region 4 additional information for revised PSD application.
May 8, 2014	Natasha Hazziez of EPA Region 4 and James Robinson of SCDHEC discussed BPCR emissions calculations via phone call.
May 21, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC updated information on removal of synthetic minor limits.
May 23, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC updated emissions spreadsheets.

May 30, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC updated emissions spreadsheets.
June 4, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss emissions calculations, synthetic minor limit removal, BACT limits, and other PSD items.
June 9, 2014	Brent Pace of BPCR emailed James Robinson of SCDHEC updated emissions spreadsheets.
June 11, 2014	Brent Pace of BPCR and James Robinson of SCDHEC discussed removal of synthetic minor limits and BACT limits.
June 17, 2014	Brent Pace of BPCR sent an email to James Robinson of SCDHEC discussing BACT limits, synthetic minor limits, and additional equipment needing BACT.
June 20, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT short-term limits, synthetic minor/PSD avoidance limits, and other items pertaining to the revised PSD application.
June 25, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT analysis.
July 2, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT analysis.
July 10, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT analysis.
July 16, 2014	SCDHEC personnel held conference call with Brent Pace of BPCR to discuss BACT analysis.
July 23, 2014	Brent Pace of BPCR and James Robinson of SCDHEC discussed BACT analysis.
July 29, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR a list of discussion items on the BACT analysis.
July 29, 2014	Brent Pace of BPCR sent an email to James Robinson of SCDHEC responses to BACT analysis discussion items.
August 7, 2014	SCDHEC personnel held conference call with BPCR and TRC to discuss BACT analysis.
August 12, 2014	TRC, on behalf of BPCR, submitted a second revised expedited PSD construction permit application to SCDHEC.
August 20, 2014	Brent Pace of BPCR and SCDHEC personnel discussed PSD application questions and potential affects of temporary compressors on BACT analysis.
August 27, 2014	Brent Pace of BPCR and James Robinson of SCDHEC briefly discussed modeling changes and control technology search.
August 29, 2014	James Robinson of SCDHEC emailed Brent Pace of BPCR a draft of the preliminary determination (PD) for comments.

October 8, 2014	The BAQ placed the PSD Preliminary Determination and PSD Construction Permit No. 0420-0029-CU on public notice for a thirty-(30) day comment period by publication in *The Post & Courier* newspaper in Charleston, South Carolina. All appropriate Federal and State Officials were notified.

II. Introduction and Preliminary Determination

Project Overview

BP Amoco Chemical Company – Cooper River Plant (BPCR) submitted a Prevention of Significant Deterioration (PSD) construction permit application to the South Carolina Department of Health and Environmental Control (SCDHEC), Bureau of Air Quality (BAQ), to modify the #1 and #2 Oxidation (OX) Units to remove limitations that prevent the units from operating at their unit design capacities (debottlenecking); and to make minor modifications to the #1 and #2 PTA Units to reduce operating costs. In general, these modifications will include improvements to the reaction environment, additional reaction air capacity, optimization of the recovery systems, improved Dehydration Tower (DHT) operation, improved energy recovery, removal of several emission points, addition of dense phase conveying and additional cooling tower capacity. These changes will result in increased actual hourly production and emissions rates, but will not increase maximum production rates or potential emission rates. This project is referred to as the OX Modernization/Debottleneck project.

The specific equipment revisions, additions, and removals included in the proposed project are as follows:

1. #1 OX unit
    - Replacement of the four existing reactors (BR-301 A-D) with a new single more efficient reactor (BR-301)
    - Replacement of the reactor overhead condenser system
    - Replacement of the air compressor rotor to reduce energy consumption
    - Direct injection of Paraxylene (PX) to the new reactor
    - Additional reactor overhead recovery capacity by replacing equipment with an improved design
    - Routing of 1st crystallizer (BD-401) vent to reactor off-gas recovery system
    - Maintain power recovery in off-gas expander by lowering upstream pressure drop
    - Conversion of dehydration tower (DHT) to azeotropic distillation unit
    - Change DHT overhead recovery system to a two-stage system by:
        - Converting existing DHT Scrubber (BT-702) to a one-stage acid scrubber
        - Routing the DHT Scrubber vent to the Low Pressure Absorber (LPA) (BT-603)
        - Revising the packing in the LPA
    - Change High Pressure Absorber (T-401) internal packing
    - Addition of dense phase conveying (conveyance of solids with less carrier gas)
    - Additional capacity for filters
    - Removal of the low pressure vent gas treatment (LPVGT) compressor (BC-710)
    - Removal of the solvent stripper (BT-605)
    - Removal of the residue evaporator (BM-606) and catalyst recovery unit (BD-625/631/632/BE-645)
    - Removal of the PX Stripper (BT-740)

- Addition of a steam turbine to generate power from excess low pressure steam
- Addition of a 82,000 gallon fixed roof NBA storage tank (size subject to change when BPCR goes through installation process)
- Replacement of existing Emergency Generator (BM-1201) with a new one
- Addition of a new Emergency Generator (BM-1204)
- Withdraw solvent/water mixture from reactor overhead condenser #1

2. #1 PTA unit
   - Revisions to crystallizer vent scrubber (CVS) (CM-301) to improve energy recovery
   - Addition of a 5th crystallizer (CD-300)
   - Addition of dense phase conveying
   - Replacement of dryer (CM-403B)

3. #2 OX unit
   - Direct injection of PX to reactor
   - Re-rating (Modification) of air compressor for additional capacity
   - Replacement of reactor overhead condenser
   - Conversion of dehydration tower (DHT) (DT-403) to an azeotropic distillation unit
   - Modification of packing or trays in DHT (DT-403), High Pressure Absorber (HPA) (DT-111), LPA (DT-302), Dryer Scrubber (DT-301) and High Pressure Vent Gas Treatment System (HPVGTS) Scrubber (DT-1821)
   - Routing of DHT (DT-403) vent to LPA system (DT-302)
   - Addition of dense phase conveying
   - Removal of Low Pressure Vent Gas Treatment (LPVGT) System compressor (DC-304)
   - Removal of solvent stripper (DT-402) system
   - Removal of the residue evaporator (DM-403) and catalyst recovery unit (DD-412/413/414/DE-416)
   - Removal of PX Stripper (DT-404)
   - Addition of a steam turbine to generate power from excess steam
   - Addition of a 75,000 gallon fixed roof NBA storage tank (size subject to change when BPCR goes through installation process)

4. #2 PTA Unit
   - Modifications to CVS (DM-601) to improve energy recovery
   - Modification of piping system from PTA Feed Drum (DD-500) to the Sundyne pumps
   - Addition of a 4th Sundyne pump
   - Addition of dense phase conveying
   - Replacement of dryer (DM-703)

5. Cooling Towers
   - Additional #1 Cooling Tower capacity
   - Additional #2 Cooling Tower capacity

The project will also include smaller items that will occur on all the units in the following general categories:

1. Additional and/or improved automation, multivariable control schemes, and on-line analyzers to increase unit reliability and improve process control.
2. Replacement of process equipment and piping that are negatively impacting maintenance costs and unit reliability.
3. Replacement of obsolete or end-of-life equipment such as piping, instruments, and computer equipment, where replacement parts are no longer available and equipment that has been determined to be too worn or corroded.
4. Replacement of exchangers and vessels to improve metallurgy, reduce corrosion, and reduce maintenance costs.

As part of this project, BPCR is removing synthetic minor PSD avoidance limits that were established in construction permits 0420-0029-CF, -CJ, -CP, and -CR for the following emission points: #1 OX DHT Scrubber, #1 and #2 OX LPA's, #1 and #2 OX HPVGTS, #2 PTA Crystallizer Vent Scrubber (CVS), #2 OX HPVGTS Heater, and the combined limit for CR#1 and CR#2 Plants. The table below lists the individual synthetic minor limits that will be removed. These emission points have been included in the BACT analysis.

Synthetic Minor Limits To Be Removed

OP ID	CP ID(s)	Process/Equipment (Equipment ID)	Pollutant	Emission Limitation (lb/hr)	Emission Limitation (TPY)	Proposed BACT Limit (lb/hr)
03	CP & CR	#1 OX LPA (BT-603)	VOC	40	80	9.60
03	CR	#1 OX LPA (BT-603)	CO	N/A	40	4.1014.0
03	CP & CR	#1 OX DHT Scrubber (BT-702)	VOC	60	165	N/A(1)
03	CR	#1 OX DHT Scrubber (BT-702)	CO	N/A	380	
03	CJ & CR	#1 OX HPVGTS (HPA (BT-401))	VOC	85	80	4.70
03	CJ & CR	#1 OX HPVGTS (HPA (BT-401))	CO	1452	375	87.972.0
05	CF(2)	#2 OX LPA (DT-302)	VOC	15.57	N/A	8.85
		#2 OX HPVGTS (HPA (DT-111))				3.50
05	CF(2)	#2 PTA Unit CVS (DM-601)	VOC	25.6	N/A	20.0
05	CF(2)	#2 OX Fugitives	VOC	3.5	N/A	HON LDAR
05	CF(2)	#2 OX HPVGTS Fired Heater	VOC	0.84	N/A	0.0055 lb/MM BTU
03-06	CP	Combined total for CR#1 & CR#2	VOC	N/A	1825	Replaced with individual vent limits

(1) The #1 OX DHT Scrubber will no longer vent to the atmosphere and is being routed to the #1 OX LPA. The #1 OX LPA BACT limit accounts for the #1 OX DHT Scrubber emissions.

(2) Construction Permit 0420-0029-CF established a total PSD avoidance limit of 49.26 lb VOC/hr for the Cooper River #2 Plant. This limit consisted of these four sources of emissions, and the following sources of emissions: Incremental increase from the Tank Farm (0.02 lb/hr) and Wastewater Fugitives (3.11 lb/hr), the Anaerobic Reactor (0.31 lb/hr), and the CO_2 Stripper (0.35 lb/hr). A revised PSD avoidance SM limit established through construction permit 0420-0029 will be the sum of the emissions from the Tank Farm, Wastewater Fugitives, Anaerobic Reactor, and CO_2 Stripper (3.79 lb/hr).

Due to emissions increases associated with this proposal, the project is subject to S.C. Regulation 61-62.5, Standard No. 7, "Prevention of Significant Deterioration (PSD)". This regulation is equivalent to the Federal Prevention of Significant Deterioration of Air Quality regulations in Title 40 Code of Federal Regulations (CFR) Section 52.21. Pursuant to these regulations, new major stationary sources and modifications to major stationary sources of air pollution must demonstrate that they will not significantly deteriorate the air quality in their region. BPCR has potential emissions of VOC and CO, which exceed the significance levels allowed in this regulation. The PSD review was conducted for VOC and CO and includes a Best Available Control Technology (BACT) determination and Ambient Air Impact Analyses.

Regulatory Applicability

The increased production capacity results in potential emissions that exceed the PSD significant thresholds. By virtue of the proposed increase, this project is subject to review under the following standards in S.C. Regulation 61-62 and Federal standards:

- SC Regulation 61-62.5, Standard No. 2 "Ambient Air Quality Standards"
- SC Regulation 61-62.5, Standard No. 3 "Waste Combustion and Reduction"
- SCC Regulation 61-62.5, Standard No. 4 "Emissions from Process Industries"
- SC Regulation 61-62.5, Standard No. 7 "Prevention of Significant Deterioration"
- SC Regulation 61-62.60 "South Carolina Designated Facility Plan and New Source Performance Standards"
- SC Regulation 61-62.61 "National Emission Standards for Hazardous Air Pollutants (NESHAPs)"
- S.C. Regulation 61-62.63 "NESHAPs for Source Categories"
- 40 CFR 60, Subpart A "Standards of Performance for New Stationary Sources - General Provisions"
- 40 CFR 60, Subpart Db "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units"
- 40 CFR 60, Subpart VV "Standard of Performance for Equipment Leaks of VOC in Synthetic Organic Chemical Manufacturing Industry (SOCMI) for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006"
- 40 CFR 60, Subpart VVa "Standard of Performance for Equipment Leaks of VOC in Synthetic Organic Chemical Manufacturing Industry (SOCMI) for which Construction, Reconstruction, or Modification Commenced After November 7, 2006"
- 40 CFR 60, Subpart III "Standard of Performance for VOC Emissions from SOCMI Air Oxidation Unit Processes"
- 40 CFR 60, Subpart NNN "NSPS for VOC Emissions from SOCMI Distillation Operations"
- 40 CFR 60, Subpart IIII "NSPS for Stationary Compression Ignition Internal Combustion Engines"
- 40 CFR 61, Subpart FF "National Emission Standards for Benzene Waste Operations"
- 40 CFR 63, Subpart A "General Provisions"
- 40 CFR 63, Subpart F "National Emission Standards for Organic Hazardous Air Pollutants (NESHAPs) from the SOCMI"

- 40 CFR 63, Subpart G “NESHAPs From the SOCMI Process Vents, Storage Vessels, Transfer Operations, and Wastewater”
- 40 CFR 63, Subpart H “NESHAPs for Equipment Leaks”
- 40 CFR 63, Subpart ZZZZ “National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Stationary Reciprocating Internal Combustion Engines (RICE)”
- 40 CFR 63, Subpart DDDDD “NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters”
- 40 CFR Part 64 “Compliance Assurance Monitoring (CAM)”

III. Detailed Process Description

BPCR is a chemical manufacturing facility located in Wando, South Carolina that produces purified terephthalic acid (PTA). PTA is a white, inert powder used to make polyester fibers, bottles, and films. The major raw materials in the production of PTA are Paraxylene (PX), acetic acid, caustic soda, and hydrogen. Plant operation consists mainly of: 1) utilities 2) production of crude TA, 3) purification into PTA, 4) product loading/shipping, and 5) waste treatment along with some additional areas at the plant. There are two units that manufacture PTA: Cooper River #1 (CR#1), which consists of the #1 Oxidation (OX) Unit and the #1 PTA Unit; and Cooper River #2 (CR#2), which consists of the #2 Oxidation (OX) Unit and the #2 PTA Unit. The #1 and #2 OX Units produce crude TA and the #1 and #2 PTA Units purify the crude TA, to make PTA.

#1 & #2 Oxidation Units

In each Oxidation (OX) unit, a BPCR proprietary process is used for the catalytic liquid phase air oxidation of paraxylene (PX) to produce crude terephthalic acid (TA). Acetic acid (HAC) and catalyst solution are mixed in a feed mix drum. The feed mix from the drum, PX (by direct injection), and air from the process air compressors are continuously fed to the reactors. Exothermic heat from the reaction is removed by flashing off, and then condensing the boiling reaction solvent. A portion of this condensate is withdrawn to control the water concentration in the reactor and the remainder is refluxed back to the reactor.

Reactor effluent is depressurized and cooled to filtering conditions in a series of crystallizers. Air is fed to the first crystallizer for additional reaction. The crystallizer temperatures are controlled by allowing a portion of the reaction solvent to flash off. The crystallizer vent streams are sent to the dehydration tower (DHT) or the high pressure absorber (HPA) for recovery of valuable materials. The DHT also removes water formed in the reaction. The DHT is an azeotropic distillation system where the vent streams from the system are sent thru two-stage scrubbing. This two-stage scrubbing recovers PX and HAC before being vented to the atmosphere through the LPA. The excess reaction water removed by the DHT system is sent to wastewater treatment. The crystallizer precipitate, TA, is recovered by filtration and finally dried. The dried TA solids are conveyed to the OX intermediate storage silos (TA silos) and stored for additional processing in the PTA unit.

The off-gas from the OX reactors is sent through a recovery device, the HPA, before being sent to a control device, the high pressure vent gas treatment system (HPVGTS) in which CO, VOC, and HAP are nearly totally destroyed and emitted to the atmosphere. The HPVGTS reactor contains catalyst bricks that are routinely changed out based on their activity and mechanical condition. Further processing in the OX unit is required to recover and purify HAC from the reactor outlet, crystallizer solvent withdrawal streams, and also from the un-recycled mother liquor stream.

#1 & #2 Purified Terephthalic Acid Units

The purified terephthalic acid (PTA) unit is also a continuous operation. Crude terephthalic acid (TA) is fed from the TA silos to the feed slurry drum to produce a slurry of TA crystals and water. The slurry is heated to dissolve the TA and then the slurry enters the hydrogenation reactor where it reacts to convert the impurities into a form that can be separated from the product. The PTA reactor catalyst is routinely changed out based on its activity and mechanical condition. After reaction, the solution goes through a cycle of lowering the pressure and cooling to crystallize the PTA. A portion of the aromatic acids in the mother liquor are recovered by cooling and filtering the mother liquor; the aromatic acids are recycled back to the OX reaction unit.

The crystallized PTA is recovered from the mother liquor by separation in the filtration section of the unit. The final product is dried and transferred to the PTA day silos and then to the PTA product storage silos.

Product Loading and Shipping

The PTA storage system is comprised of six large silos that are used to manage product transfers, packaging, loading and shipping. Shipping personnel package the product from the large silos into various containers and ship it to the customers.

IV. Significant Emission Rates

As shown in Table IV-1, this project exceeds the significant threshold as defined under PSD for CO and VOC emissions. Emissions calculations for the modified units were based on actual-to-potential test to determine if there was a significant emissions increase.

Table IV-1. PSD Applicability Analysis

Pollutant	Controlled Emissions Increase	PSD Significant Threshold	Significant Increase?
	TPY	TPY	
PM	7.0	25	No
PM_{10}	6.6	15	No
$PM_{2.5}$	5.8	10	No
SO_2	0.2	40	No
NO_X	27.8	40	No
CO	644.8 618.5	100	Yes
VOC	200.3	40	Yes
CO_2e	17,300	75,000	No

V. Best Available Control Technology (BACT) Determination

A. BACT Requirement

BACT is defined as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant, taking into account energy, environmental, and economic impacts." As per S.C. Regulation 61-62.5, Standard No. 7, the BACT requirement applies to each individual new or modified affected emissions unit and pollutant emitting activity at which a net emissions increase would occur. In no case can the application of BACT result in emissions of any pollutant which would exceed emissions allowed under any applicable standard under 40 CFR 60 *New Source Performance Standard (NSPS)*, 61 *NESHAP* or 63 *NESHAP for Source Categories*.

Chapter B of the draft *New Source Review Workshop Manual* (October 1990) defines the BACT determination process as a 5-step process.

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

Opacity is not considered to be a PSD pollutant and therefore, opacity itself does not require a BACT evaluation and establishment of a BACT limit. However, BACT can include the use of visible emission limitations or work practice standards for regulated PSD pollutants. Opacity limits have been included in the draft permit as required by State and Federal regulations. BACT cannot be less stringent than an applicable NSPS or NESHAP as outlined in 40 CFR 60, 61, and 63.

The primary resource for establishing BACT is the RACT/BACT/LAER Clearinghouse (RBLC) on the Technology Transfer Network (TTN) maintained by the EPA. To establish BACT for a PSD source, state regulatory agencies query the RBLC. This database contains information about available control technologies for specific industry sources and lists the limits that other pollution control agencies have established for similar source types.

BAQ queried the RBLC for all similar process types and NSR applicable pollutants. An RBLC advanced search was queried using a standard industrial classification (SIC) code of 2869. In addition to the RBLC, the following sources were reviewed: EPA Control Technology documents (i.e. Air Pollution Control Technology Fact Sheets), NSPS and NESHAP regulations for SOCMI processes, South Coast Air Quality Management District BACT, the California Air Resources Board BACT Clearinghouse, an internet search for similar facilities, a general internet search for VOC and CO emission controls, and operating permits for existing facilities with similar processes.

BPCR queried the RBLC using process types 64.000, 64.003 and 64.999, SOCMI production, process vents, and organic chemical production. Other resources of control technology reviewed were the *EPA Air Pollution Control Technology Fact Sheets*, *EPA Air Pollution Control Cost Manual Sixth Edition* (EPA/452/B-02-001, January 2002), and the applicable NSPS and NESHAP standards. BPCR's queries did not find any control technologies that apply directly to the purified terephthalic acid (PTA) manufacturing process. BPCR also looked at sister facilities located internationally, and found that the conventional control technologies used are the same used at this facility. The sister facilities with new/modern technologies are not compatible and are not feasible to add to the conventional technology. BPCR does not have any data on control technologies for PTA facilities not owned by or joint venture with BP Amoco.

The following control technologies were found to reduce VOC and/or CO emissions. These control technologies will be used throughout the BACT Determination, but the descriptions will not be repeated for each determination.

- **Thermal Oxidizer (TO)** –A TO is a control technology that uses high temperature combustion to control gaseous pollutants, such as VOCs, HAPs and CO. Fuel and air are added to a combustion chamber through which the exhaust gases pass to maintain a high minimum operating temperature, usually 1200 – 1700 °F, and combusts the VOC into carbon dioxide (CO_2) and water (H_2O). This technology typically has a control efficiency of 99+ percent for VOCs and 95+ percent for CO.
- **Regenerative Thermal Oxidizer (RTO)** – An RTO is a control technology that is similar to a TO in the manner it controls gaseous pollutant emissions. The difference between an RTO and a TO is the increased energy efficiency an RTO achieves. This efficiency is attained by storing heat from hot exhaust gases in ceramic media as the process stream enters and exits the combustion chamber. The cooler inlet process stream then recovers the heat from the ceramic media. This technology typically has a control efficiency of 95 to 99 percent for VOCs and 98+ percent for CO.
- **Recuperative Thermal Oxidizer (RCO)** – An RCO is a control technology that is similar to a TO in the manner it controls gaseous pollutant emissions. The difference between an RCO and a TO is the increased energy efficiency that an RCO achieves. This is achieved by adding a primary and/or secondary heat exchanger within the system, where the heat exchanger(s) preheat(s) the incoming vent stream by recuperating heat from the exiting treated exhaust stream. This technology typically has a control efficiency of 90 to 99 percent for VOCs and 98+ percent for CO.
- **Catalytic Thermal Oxidizer (CTO)** – A CTO is a control technology that oxidizes (combusts) gaseous pollutants at temperatures several hundred degrees lower than a TO, RTO, and RCO (typically 500 - 1,000 °F). This is achieved by using a precious-metal catalyst, usually in the form of a bed. A catalyst is a substance used to accelerate the rate of a chemical reaction (combustion), allowing the reaction (combustion) to occur at a much lower temperature. The lower temperatures reduce the amount of supplemental heat required for the process. This technology typically has a control efficiency of 95+ percent for VOCs and 95+ percent for CO.
- **Absorber/Wet Scrubber** – An absorber/wet scrubber is a control technology that removes particulate and/or gaseous pollutants from industrial exhaust streams via contact of contaminants with a liquid absorbing/scrubbing solution. The process uses rapid gas absorption into the scrubbing solution to remove the contaminants. The

solution is usually water, or it can be other liquids that specifically target certain compounds. Typically gas enters the bottom of the absorber and passes upward through the scrubbing solution that is sprayed into the top of the scrubber. The scrubbed gas then goes through a mist eliminator where entrained liquid droplets are removed before exhausting to the atmosphere. The scrubber solution is collected in the bottom of the tower where most of the scrubbing solution is recycled to the top of the tower. This technology typically has a control efficiency of 90+ percent for VOCs, but does not control CO.

- **Adsorber** – An adsorber is a control technology that removes pollutants by adhesion to a high surface solid material (adsorbent), such as activated carbon. An adsorber can be used to capture gas or liquid contaminants. The adsorbed material can then be desorbed, removed by heat or vacuum, and reused. This technology typically has a control efficiency of 98 percent for VOCs, but does not control CO.
- **Condenser** – A condenser is a control technology that removes a pollutant by converting the pollutant from a gas to a liquid. This can be done by either cooling, or increasing the pressure of the gas. The condensed liquid can be recovered or recycled. Often, condensers are heat exchangers, having various designs and sizes. This technology typically has a control efficiency of 50 - 90 percent depending on the concentration of VOC compounds present in the gas stream, but does not control CO emissions.
- **Flare** – A gas flare, also known as a flare stack, is a control technology that uses a high temperature (up to 2000 °F) open air flame to burn off flammable gases such as VOCs. The vent stream being combusted must have a heating value greater than 300 British thermal units/standard cubic feet (Btu/scf) to maintain combustion, or a supplemental fuel must be added to meet the minimum of 300 Btu/scf. The control requirements in 40 CFR 60.18 states a flare shall only be used as a control device if the vent stream being combusted has a net heating value of at least 200 Btu/scf. to prevent blowing out the flare flame. This technology typically has a control efficiency of 95+ percent for VOCs. A flare is not a good option to use for control of CO emissions because it can produce as much CO as it controls.
- **Boiler** – A boiler is an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A boiler can be used a control device where waste gas streams are fed directly into the boiler flame, essentially operating as thermal oxidizer. This technology typically has a control efficiency of 99+ percent for VOCs and 95+ percent for CO.
- **Biofiltration** – Biofiltration is a control technology that uses living material (microorganisms) to metabolize or breakdown organic pollutants in contaminated air streams. The contaminated air stream is slowly pumped through a packed bed or other filter media, and pollutants are absorbed into a thin layer of moisture, called biofilm, surrounding the particles that make up the filter media. Biological degradation of pollutants occurs in this biofilm, resulting in the byproducts of CO_2 and H_2O. Biofilters are very sensitive to temperature and moisture content, and work best with low VOC

concentrations (<1,000 ppm). This technology typically has a control efficiency of 90+ percent for VOCs, but does not control CO.

- **Good Combustion Practices –** Good combustion practices are methods used to maintain combustion equipment (such as periodic burner tune-ups) and operate within recommended combustion air and fuel ranges (i.e. good air/fuel mixing in combustion zone). This promotes efficient and complete combustion of fuel, which results in reduction of combustion emissions.
- **Good Design and Operating Practices** – Good design and operating practices are opportunities for a stationary source to reduce or eliminate pollutants through cost-effective changes in production, operation and raw materials use. Good design practice is the planning of processes or equipment that either inherently lowers pollutants, or that minimizes emissions. Good operating practices are the use of methods and procedures (i.e.; environmental management systems) to minimize emissions. The intent of these practices is to minimize the formation of CO, rather than use add-on controls to reduce or eliminate CO emissions on the “back end” of the process(es).

The proposed project includes modified emission units that are subject to PSD review and will have VOC and CO emissions increases requiring a BACT analysis. The table below represents these emission units, with associated equipment, and the estimated potential VOC and CO emissions from these emission units.

Table V.A-1: Potential VOC & CO Emissions*

Emission Unit	Equipment (Equipment ID)	VOC Emissions		CO Emissions	
		lb/hr	tpy	lb/hr	tTpy
#1 OX	High Pressure Absorber (BT-401)	234	1024.9	1758	7700.7
	Low Pressure Absorber (BT-603)	9.6	42	4.114.0	1861.3
	Fugitives	21.5	94.4	N/A	N/A
	Emergency Generator (BM-1201)	0.07	0.003	0.59	0.03
	Emergency Generator (BM-1204)	0.02	0.001	0.57	0.03
#2 OX	High Pressure Absorber (DT-111)	175	766.5	1500	6571.5
	Low Pressure Absorber (DT-302)	8.85	38.8	3.47	15.2
	HPVGTS Fired Heater (DB-1813)	0.08	0.35	1.24	5.41
	Fugitives	21.85	95.7	N/A	N/A
#1 PTA	Crystallizer Vent Scrubber (CM-301)	20	87.6	24	105.1
#2 PTA	Crystallizer Vent Scrubber (DM-601)	20	87.6	20	87.6

* Note that potential emissions are based on no add-on controls for all equipment. The only equipment that currently has controls are the High Pressure Absorbers. Fugitive emissions are based on the LDAR programs currently in place. Emergency Generator PTE’s are based on 100 hours per year limit.

B. BACT for VOCs from #1 and #2 Oxidation (OX) Unit High Pressure Absorbers

Each OX Unit's reactor will send overheads to an existing scrubber to recover paraxylene (PX) and then to a recovery device (High Pressure Absorber (HPA)) to recover mainly acetic acid and any residual PX. The HPA outlets are sent to the High Pressure Vent Gas Treatment System (HPVGTS), which consists of a CTO to control VOCs, HAPs, and CO; followed by a bromine scrubber, to control methyl bromide. The VOC PTE from the #1 OX HPA is 1024.9 tons per year, and from the #2 OX HPA is 766.5 tons per year.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce VOC emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Absorber/Wet Scrubber
- Carbon Adsorber
- Condenser
- Flare
- Boiler
- Biofiltration

Step 2: Technical Feasibility of Options

The use of the boiler is not technically feasible because the methyl bromide present in the waste gas streams would cause severe corrosion in the carbon steel boilers. In addition, the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, and the boiler cannot handle this.

The use of the thermal combustion options (TO, RTO, RCO, CTO, and flare) and recovery options (absorber/scrubber, carbon adsorber, and condenser) are technically feasible since they all are successfully used in similar processes. Although the addition of an absorber/wet scrubber is technically feasible, it would have a lower control efficiency than normal because the waste stream is already being controlled by a two-stage absorber system.

The biofiltration control option is technically feasible because it is successfully used in similar processes. However, it would have a lower control efficiency than normal because of the large amount of methyl bromide present. Methyl bromide is a very toxic biocide and will kill a substantial amount of the microorganisms used to biodegrade the VOCs.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their VOC emission reduction potential (% control efficiency) for the HPA.

Table V.B-1: Control Technology Rankings for HPA VOC BACT

Control Option	Efficiency (%)
TO	99
RTO	99
RCO	99
CTO (existing)	98
Flare	98
Carbon Adsorption/TO	96
Condenser	60
Absorber/Wet Scrubber	50
Biofiltration	35

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.B-2: Summary of #1 & #2 OX Units HPA VOC BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO	1,014.7	$29,021,335	$28,600	11,306,341	No
RTO	1,014.7	19,211,876	18,935	1,002,328	No
RCO	1,014.7	23,432,003	23,100	5,563,302	No
CTO (Existing)	1,004.4	567,782	519	360,206	No
Flare	1,004.4	19,344,753	19,260	2,072,818	No
Carbon Adsorption/TO*	983.9	5,437,736	5,530	28,257	No
Condenser	615	1,772,038	3,458	0	No
Absorber/Wet Scrubber	512.5	271,303	441	0	No
Biofiltration	358.8	17,495,731	48,762	7,578	No

* The Annualized Operating Cost for Carbon Adsorption/TO control is less than the TO control option because the Carbon Adsorption/TO control option uses much less supplemental fuel due to the higher concentration of VOCs from the Adsorber.

Economic Impact Analysis

As shown in Table V.B-2 above, the use of a TO, RTO, RCO, or Flare as a control option is not as cost effective as the existing CTO, which either has the same or relatively same VOC control efficiency (98 to 99%).

Energy Impact Analysis
The feasible control options were evaluated for energy impacts, and it was determined that no unusual energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis
BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste. Operation of the condenser would create large quantities of liquid waste that will need to be treated prior to discharge. The operation of the absorber/wet scrubber option would generate large quantities of wastewater that will need to be treated prior to discharge.

Step 5: Select BACT Controls and Limits

BACT has been determined to be the existing CTOs. Using the control efficiency of the existing CTOs, the VOC limit for the #1 and #2 OX HPA has been determined to be 4.70 and 3.50 lb/hr, respectively, based on a 3-hour block average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will monitor each CTO inlet and outlet temperature, while processes venting to each CTO are in operation. These parameters will be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period (midnight to midnight), and shall be averaged together for a daily reading. The parameters used to demonstrate compliance will be the daily average inlet temperature and the daily average reactor delta temperature of the CTO. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met:

- The daily average for a parameter is outside the approved monitoring range.
- The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.

A source test to determine VOC emission rates from each CTO is required within 180 days after startup and every three years thereafter. If the catalyst is replaced in a CTO, a new source test schedule shall be required as follows: A source test for VOC and CO emissions shall be conducted within 90 days after changing the catalyst in a CTO, and every three years thereafter.

In most cases, a source test for control efficiency is a BACT required monitoring parameter for control devices. However, through discussions with BPCR, a control efficiency test will not be required for the CTOs because historical testing has shown that outlet stream emissions (and sometimes inlet stream emissions) are at or below detection levels, making it difficult to measure efficiencies.

C. BACT for VOCs from #1 and #2 Oxidation (OX) Unit Low Pressure Absorbers

Each Oxidation (OX) Unit utilizes an existing recovery device (Low Pressure Absorber (LPA)) to recover acetic acid from several process streams. The acetic acid, which acts as a solvent in the process, is purified and reused in the process. This recycling of the solvent reduces purchase costs. Part of this project is to optimize acetic acid recovery. These absorbers are used as recovery devices and currently do not have controls. The VOC PTE from the #1 OX LPA is 42 tons per year, and from the #2 OX LPA is 38.8 tons per year.

<u>Step 1: Identify All Available Control Technologies</u>

The following control technologies were found to reduce VOC emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Absorber/Wet Scrubber
- Carbon Adsorber
- Condenser
- Flare
- Boiler
- Biofiltration

<u>Step 2: Technical Feasibility of Options</u>

The use of the boiler is not technically feasible because the methyl bromide present in the waste gas streams would cause severe corrosion in the carbon steel boilers. In addition, the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, and the boiler cannot handle this.

The use of the thermal combustion options (TO, RTO, RCO, CTO, and flare) and recovery options (absorber/wet scrubber, carbon adsorber, and condenser) are technically feasible since they all are successfully used in similar processes. Although the addition of an absorber/wet scrubber is technically feasible, it would have a lower control efficiency than normal because the waste stream is already being controlled by a two-stage absorber system.

The biofiltration control option is technically feasible because it is successfully used in similar processes. However, it would have a lower control efficiency than normal because of the large amount of methyl bromide present. Methyl bromide is a very toxic biocide and will kill a substantial amount of the microorganisms used to biodegrade the VOCs.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their VOC emission reduction potential (% control efficiency).

Table V.C-1: Control Technology Rankings for LPA VOC BACT

Control Option	Efficiency (%)
TO	99
RTO	99
RCO	99
CTO (New)	98
CTO (Existing)	98
Flare	98
Carbon Adsorption/TO	96
Biofiltration	57
Refrigerated Condenser	55
Absorber/Wet Scrubber	50

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.C-2: Summary of #1 & #2 OX Units LPA VOC BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO	41.6	$535,524	$12,873	$344,412	No
RTO	41.6	464,581	11,168	188,922	No
RCO	41.6	500,627	12,034	97,422	No
CTO (New)*	41.2	375,878	9,123	100,324	No

Table V.C-2: Summary of #1 & #2 OX Units LPA VOC BACT Impact Analysis					
Control Option	**Emission Reduction (tpy)**	**Annualized Operating Cost ($)**	**Average Cost Effectiveness ($/ton)**	**Increased Energy Usage ($/yr)**	**Adverse Environmental Impacts?**
CTO (Existing)	41.2	1,062,446	25,788	625,604	No
Flare	41.2	2,925,574	71,010	2,728,146	No
Carbon Adsorber/TO	40.4	491,516	12,166	14,811	No
Biofiltration	23.9	198,756	9,402	7,600	No
Refrigerated Condenser	23.1	367,259	15,900	17,050	No
Absorber/Wet Scrubber	21.0	425,373	20,233	3,789	No

* The Annualized Operating Cost for the New CTO is less than the Existing CTO because the New CTO would operate at a lower pressure and be much smaller since it would be only controlling emissions from the LPA.

Economic Impact Analysis

The control technologies listed in Table V.C-2 above are not cost effective. All of the control technologies would require additional equipment (i.e. fan, blower, compressor) to raise the pressure of the LPA outlet streams. The use of a direct flame oxidizer option (TO, RTO, or RCO) would also not be cost effective due the need to have stainless steel metallurgy. This is recommended for streams containing halogen compounds (methyl bromide in this case) where there can be formation of highly corrosive acid gases. The use of absorber/wet scrubber is also not cost effective because of the low VOC concentration of the LPA outlet stream.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no additional energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste. Operation of the condenser would create large quantities of liquid waste that will need to be treated prior to discharge. The operation of the absorber/wet scrubber option would generate large quantities of wastewater that will need to be treated prior to discharge.

Step 5: Select BACT Controls and Limits

Because none of the control options were deemed feasible, a VOC limit, along with monitoring, recordkeeping, and reporting was set as BACT. Using the recovery efficiency of the LPAs, the

VOC limit for the #1 and #2 OX LPA has been determined to be 9.60 and 8.85 lb/hr, respectively, based on a 3-hour block average, each. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will monitor LPA top liquid flow and LPA top temperature, while processes venting to the LPA are in operation. These parameters will be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period, and shall be averaged together for a daily reading. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met:

- The daily average for a parameter is outside the approved monitoring range.
- The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.

A source test to determine VOC emission rates from the LPA units is required within 180 days after startup, and every 3 years thereafter.

D. BACT for VOCs from #1 and #2 Oxidation (OX) Unit Fugitives

Each Oxidation (OX) Unit has equipment that emits fugitive VOC emissions from valves, flanges, drains, vents, pumps, relief valves, etc. Currently the OX units' fugitive emissions are being minimized through various leak detection and repair (LDAR) programs, to include NSPS VV, a modified version of NSPS VV, and the HON. For the BACT analysis, BPCR used the NSPS VV LDAR program as the baseline, and an upgrade to either a NSPS VVa or a HON LDAR will be considered. The fugitive VOC PTE and baseline from the #1 OX unit is 94.4 tons per year, and from the #2 OX unit is 95.7 tons per year.

<u>Step 1: Identify All Available Control Technologies</u>

An LDAR program was the only control technology found to apply to fugitive emissions. An LDAR program is a work practice designed to identify leaking equipment so that emissions can be reduced through repairs. A component that is subject to LDAR requirements must be monitored at specified, regular intervals to determine whether it is leaking or not. Any leaking component must be repaired or replaced within a specified time frame. LDAR programs are governed by several different regulations, including National Emission Standards for Hazardous Air Pollutant (NESHAPs), New Source Performance Standards (NSPS) Subpart VV/VVa, the Hazardous Organic NESHAP (HON), Maximum Achievable Control Technology (MACT), State Implementation Plans (SIPs), the Resource Conservation and Recovery Act (RCRA), and other state or local requirements (i.e. - Consent Decrees). Typically a facility uses a combination of LDAR programs, as BPCR is currently.

Step 2: Technical Feasibility of Options

LDAR programs are a widely accepted control technology used to reduce fugitive VOC emissions in chemical plants, making them technically feasible for BPCR.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their VOC emission reduction potential (Effectiveness Factor). The table below uses two example components (valve and pump) to compare effectiveness of each control option.

Table V.D-1: Control Technology Rankings for OX Unit Fugitives VOC BACT

CONTROL OPTION	Valves - Light Liquid Service Control Effectiveness (%)	Pumps - Light Liquid Service Control Effectiveness (%)
HON MACT LDAR Program	88	75
NSPS VVa LDAR Program	88	71
LDAR VV Program (existing)	61	69

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.D-2: Summary of #1 & #2 OX Units Fugitive VOC BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)
Upgrade NSPS VV to HON	146.0	$72,600	$497
Upgrade NSPS VV to VVa	46.4	59,640	1,285

Economic Impact Analysis

As shown in Table V.B-2 above, the top control option is also the most cost effective.

Energy Impact Analysis

Upgrading to the HON LDAR program does not contribute to any unusual energy penalties or benefits.

Environmental Impact Analysis
Upgrading to the HON LDAR program does not contribute to any adverse environmental impacts.

Step 5: Select BACT Controls and Limits

BACT has been determined to be an upgrade to the HON LDAR program (covered under Regulation 40 CFR 63 Subpart H) for all fugitive VOC emissions in the #1 and #2 OX Units. All VOCs will be treated as HAPs for determining monitoring applicability. These limits shall apply at all times including during startup, shutdown, and malfunction. Monitoring, recordkeeping, and reporting will be in accordance with the HON LDAR (63.160 through 60.182). Testing shall be performed as per 40 CFR 63.180.

E. BACT for VOCs from #1 and #2 PTA Crystallizer Vent Scrubbers (CVS)

Each Purified Terephthalic Acid (PTA) Unit utilizes crystallizers to purify the crude TA. These crystallizers flash off liquids in order to control the temperature of the crystallizers. The vapor stream from each crystallizer is sent to a vent scrubber to remove particulate matter (PM), which is mostly PTA. The scrubbed vapor from the CVS, consisting of mostly water (99%) and small amounts of VOCs, is vented to the atmosphere. The VOC PTE from the #1 PTA and #2 PTA CVS is 87.6 tons per year, each, based on a 3-hour block average. These limits shall apply at all times including during startup, shutdown, and malfunction.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce VOC emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Absorber/Wet Scrubber
- Carbon Adsorber
- Condenser
- Flare
- Boiler
- Biofiltration

Step 2: Technical Feasibility of Options

The operation of a flare is not technically feasible, because the exhaust streams from the crystallizers is 99% water and have very low heating values (less than 5 Btu/scf). The operation of a carbon adsorber is not technically feasible, because at moisture contents over 50%, the water molecules compete with the VOC molecules for adsorption. This significantly lowers the capacity, and therefore the efficiency, of the adsorber system. The use of the boiler is not technically feasible because the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, and the boiler cannot handle this.

The use of the remaining control options is technically feasible since they all are successfully used in similar processes. The control efficiency of the biofiltration control option would be lower than typical due to the presence of VOC compounds that are not water soluble. Additionally, the large amounts of water vapor in the inlet stream would require dehumidification prior to being sent to the biofiltration and absorber/wet scrubber control options.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their VOC emission reduction potential (% control efficiency).

Table V.E-1: Control Technology Rankings for Crystallizer Vent Scrubber VOC BACT

Control Option	Efficiency (%)
TO	99
RTO	99
RCO	99
CTO (New)	98
CTO (Existing)	98
Absorber/Wet Scrubber	90
Biofiltration	70
Condenser	60

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.E-2: Summary of CVS VOC BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO	86.7	$1,606,826	$18,533	$1,420,194	No
RTO	86.7	1,107,759	12,780	840,446	No
RCO	86.7	1,772,897	20,450	1,342,851	No
CTO (New)*	85.8	1,214,489	14,155	913,344	No
CTO (Existing)	85.8	1,748,926	20,384	1,428,322	No
Absorber/Wet Scrubber	78.8	717,878	9,110	11,366	No
Biofiltration	65.7	495,525	7,542	9,472	No
Condenser	52.6	438,446	8,335	18,944	No

* The Annualized Operating Cost for the New CTO is less than the Existing CTO because the New CTO would operate at a lower pressure and be much smaller since it would be only controlling emissions from the LPA.

Economic Impact Analysis

As shown in Table V.E-2 above, all the control options are not cost effective. All of the control technologies would require additional equipment (i.e. fan, blower) to raise the pressure of the CVS outlet streams. Use of a combustion control option (TO, RTO, RCO, CTO) would require large amounts of supplemental fuel and air to incinerate the waste because of the large volume of inert gas in the CVS outlet streams. Use of the existing CTO would require a compressor (much more costly than a fan/blower) to provide the pressure required to route the CVS outlet stream to the HPVGTS. Use of the biofiltration and absorber/wet scrubber control options would require a dehumidification system to remove the large volume of water from the CVS outlet streams, which also increases cost.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no additional energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste. Operation of the absorber/wet scrubber or condenser would create large quantities of liquid waste that will need to be treated prior to discharge.

Step 5: Select BACT Controls and Limits

Because none of the control options were deemed feasible, a VOC limit, along with monitoring, recordkeeping, and reporting was set as BACT. Using the uncontrolled emissions of the CVS, the VOC limit for the #1 and #2 PTA CVS has been determined to be 20.0 lb/hr, each, based on a 3-hour block average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will be required to calculate and maintain hourly VOC emissions. Hourly VOC emissions shall be calculated on a 3-hour block average. Reports of the calculated values shall be submitted semiannually, and maintained on site for a period of at least 5 years.

A source test to determine VOC emission rates from each CVS is required within 180 days after startup, and every 3 years thereafter.

F. BACT for CO from #1 and #2 Oxidation (OX) Unit High Pressure Absorbers

As discussed in the VOC BACT analysis for the HPAs, each OX Unit utilizes the HPA as a recovery device to reclaim mainly acetic acid, and residual paraxylene. CO is created as byproduct from the unwanted side reaction of oxygen and acetic acid in the reactor. The HPA outlets are sent to the High Pressure Vent Gas Treatment System (HPVGTS), which consists of a Catalytic Thermal Oxidizer (CTO), followed by a bromine scrubber. The HPVGTS controls VOCs, HAPs, and CO. The CO PTE from the #1 OX HPA is 7700 tons per year, and from the #2 OX HPA is 6571.5 tons per year.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce CO emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Flare
- Boiler
- Good Combustion Practices

Step 2: Technical Feasibility of Options

The use of a flare is not technically feasible, since more CO emissions are created, from the burning of required supplemental fuel, than destroyed. Good combustion practices are not technically feasible because the HPA is not a combustion process. The use of the boiler is not technically feasible because the methyl bromide present in the waste gas streams would cause severe corrosion in the carbon steel boilers. In addition, the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, which the boiler cannot handle. The use of the thermal combustion options (TO, RTO, RCO, and CTO) is technically feasible since they all are successfully used in similar processes.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their CO emission reduction potential (% control efficiency).

Table V.F-1: Control Technology Rankings for HPA CO BACT

Control Option	Efficiency (%)
TO	95
RTO	95
RCO	95
CTO (Existing)	95

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.F-2: Summary of #1 & #2 OX Units HPA CO BACT Impact Analysis

Control Option	Emission Reduction (tpy)	Annualized Operating Cost ($)	Average Cost Effectiveness ($/ton)	Increased Energy Usage ($/yr)	Adverse Environmental Impacts?
TO*	7,160.6	$29,021,335	$4,060	11,306,341	No
RTO*	7,288.6	19,211,976	2,636	1,362,534	No
RCO*	7,231.6	23,400,467	3,236	5,923,508	No
CTO (Existing)**	7,297.6	567,782	78	360,205	No

* These control options have CO generated from combustion of supplemental fuel and VOCs in the waste gas stream, slightly off-setting the CO reduction.

** This control option has CO generated from combustion of VOCs in the waste gas stream, slightly off-setting the CO reduction.

Economic Impact Analysis

As shown in Table V.F-2 above, the use of a TO, RTO, or RCO control option is not as cost effective as the existing CTO, which has the same CO control efficiency of 95%.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no unusual energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste.

Step 5: Select BACT Controls and Limits

BACT has been determined to be the existing CTO's. Using the control efficiency of the existing CTOs, the CO limit for the #1 and #2 OX HPA has been determined to be 87.972.0 and 75.0 lb/hr, respectively, based on a 30-day rolling average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will monitor each CTO inlet and outlet temperature, while processes venting to each CTO are in operation. These parameters will be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period (midnight to midnight), and shall be averaged together for a daily reading. The parameters used to demonstrate compliance will be the daily average inlet temperature and the daily average reactor delta temperature of the CTO. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met:

- The daily average for a parameter is outside the approved monitoring range.
- The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.

A source test to determine VOC emission rates from each CTO is required within 180 days after startup and every three years thereafter. If the catalyst is replaced in a CTO, a new source test schedule will be required as follows: A source test for VOC and CO emissions shall be conducted within 90 days after changing the catalyst in a CTO, and every three years thereafter.

In most cases, a source test for control efficiency is a BACT required monitoring parameter for control devices. However, through discussions with BPCR, a control efficiency test will not be required for the CTOs because historical testing has shown that outlet stream emissions (and sometimes inlet stream emissions) are at or below detection levels, making it difficult to measure efficiencies.

C.G. BACT for CO from #1 and #2 Oxidation (OX) Unit Low Pressure Absorbers

As discussed in the VOC BACT analysis for the LPAs, each OX Unit utilizes the LPA as a recovery device to reclaim acetic acid. CO is created as byproduct from the unwanted side reaction of oxygen and acetic acid in the reactor. The LPAs do not recover or control any CO; and therefore, all CO is emitted to the atmosphere. There are currently no controls on the LPAs. The CO PTE from the #1 OX LPA is 18 61.3 tons per year, and from the #2 OX LPA is 15.2 tons per year.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce CO emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Flare
- Boiler
- Good Combustion Practices
- Good Design and Operating Practices

Step 2: Technical Feasibility of Options

The use of a flare is not technically feasible, since more CO emissions are created, from the burning of required supplemental fuel, than destroyed. Good combustion practices are not technically feasible because the LPA is not a combustion process. The boiler is not technically feasible because the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, which the boiler cannot handle. The use of the thermal combustion options (TO, RTO, RCO, and CTO) is technically feasible since they all are successfully used in similar processes.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their CO emission reduction potential (% control efficiency).

Table V.G-1: Control Technology Rankings for LPA CO BACT

Control Option	Efficiency (%)
TO	95

Table V.G-1: Control Technology Rankings for LPA CO BACT	
Control Option	**Efficiency (%)**
RTO	95
RCO	95
CTO (New)	95
CTO (Existing)	95

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.G-2: Summary of #1 & #2 OX Units LPA CO BACT Impact Analysis					
Control Option	**Emission Reduction (tpy)**	**Annualized Operating Cost ($)**	**Average Cost Effectiveness ($/ton)**	**Increased Energy Usage ($/yr)**	**Adverse Environmental Impacts?**
TO	58.217.1	$535,524504,787	$31,3178,673	$329,068313,676	No
RTO	58.217.1	464,581352,810	27,1686,062	188,92292,646	No
RCO	58.217.1	500,627408,407	29,2767,017	97,422105,558	No
CTO (New)*	58.217.1	375,828337,895	21,9785,806	132,86996,708	No
CTO (Existing)	58.217.1	1,062,4461,170,243	62,13120,107	1,428,322625,604	No

* The Annualized Operating Cost for the New CTO is less than the Existing CTO because the New CTO would operate at a lower pressure and be much smaller since it would be only controlling emissions from the LPA.

Table V.G-3: Summary of #2 OX Units LPA CO BACT Impact Analysis					
Control Option	**Emission Reduction (tpy)**	**Annualized Operating Cost ($)**	**Average Cost Effectiveness ($/ton)**	**Increased Energy Usage ($/yr)**	**Adverse Environmental Impacts?**
TO	17.1	535,524	31,317	329,068	No
RTO	17.1	464,581	27,168	188,922	No
RCO	17.1	500,627	29,276	97,422	No
CTO (New)*	17.1	375,828	21,978	132,869	No
CTO (Existing)	17.1	1,062,446	62,131	1,428,322	No

* The Annualized Operating Cost for the New CTO is less than the Existing CTO because the New CTO would operate at a lower pressure and be much smaller since it would be only controlling emissions from the LPA.

Economic Impact Analysis

The technologies listed in Tables V.CG-2 and -3 above are not cost effective. All of the control technologies would require additional equipment (i.e. fan, blower) to raise the pressure of the LPA outlet streams. The use of a direct flame oxidizer option (TO, RTO, or RCO) would also not be cost effective due the need to have stainless steel metallurgy. This is recommended for streams containing halogen compounds (methyl bromide in this case) where there can be formation of highly corrosive acid gases.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no additional energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste.

Step 5: Select BACT Controls and Limits

Because none of the control options were deemed feasible, a CO limit, along with monitoring, recordkeeping, and reporting was set as BACT. Using the recovery efficiency of the LPAs, the CO limit for the #1 and #2 OX LPA has been determined to be 4.14.0 and 3.50 lb/hr, respectively, based on a 30-day rolling average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will be required to calculate and maintain hourly CO emissions. Hourly CO emissions shall be calculated on a 30-day rolling average. Reports of the calculated values shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years.

A source test to determine CO emission rates from the LPA units is required within 180 days after startup, and every 3 years thereafter.

D.**H. BACT for CO from #1 and #2 PTA Crystallizer Vent Scrubbers**

As discussed in the VOC BACT analysis for the CVS, each PTA Unit utilizes crystallizers to purify the crude TA. These crystallizers flash off liquids in order to control the temperature of the crystallizers. The vapor stream from each crystallizer is sent to a vent scrubber to remove particulate matter (PM), which is mostly PTA. The scrubbed vapor from the CVS consists of mostly water (99%) and small amounts of CO. The CO PTE from the #1 PTA and #2 PTA CVS is 105.1 and 87.6 tons per year, respectively.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce CO emissions from this type of source:

- Thermal Oxidizer (TO)
- Regenerative Thermal Oxidizer (RTO)
- Recuperative Thermal Oxidizer (RCO)
- Catalytic Thermal Oxidizer (CTO)
- Flare
- Boiler
- Good Combustion Practices

Step 2: Technical Feasibility of Options

The use of a flare is not technically feasible, since more CO emissions are created, from the burning of required supplemental fuel, than destroyed. Good combustion practices are not technically feasible because the CVS is not a combustion process. The boiler is not technically feasible because the large volume of inert gas in the waste stream would require large amounts of supplemental fuel and air to incinerate the waste, and the boiler cannot handle this volume. The use of the thermal combustion options (TO, RTO, RCO, and CTO) is technically feasible since they all are successfully used in similar processes.

Step 3: Ranking of Control Technologies by Control Effectiveness

The table below is a ranking of the feasible control technologies from Step 2. The controls are ranked from the most to least effective based on their CO emission reduction potential (% control efficiency).

Table V.H-1: Control Technology Rankings for CVS CO BACT

Control Option	Efficiency (%)
TO	95
RTO	95
RCO	95
CTO (New)	95
CTO (Existing)	95

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Table V.H-2: Summary of #1 & #2 PTA CVS CO BACT Impact Analysis					
Control Option	**Emission Reduction (tpy)**	**Annualized Operating Cost ($)**	**Average Cost Effectiveness ($/ton)**	**Increased Energy Usage ($/yr)**	**Adverse Environmental Impacts?**
TO	99.8	$1,594,999	$15,982	$1,413,184	No
RTO	99.8	1,107,759	11,100	840,446	No
RCO	99.8	1,722,897	17,263	1,342,851	No
CTO (New)	99.8	1,214,489	12,169	913,344	No
CTO (Existing)	99.8	1,748,926	17,524	1,428,322	No

Economic Impact Analysis

The technologies listed in Table V.H-2 above are not cost effective. All of the control technologies would require additional equipment (i.e. fan, blower) to raise the pressure of the CVS outlet streams. These control options would also require large amounts of supplemental fuel and air to incinerate the waste because of the large volume of inert gas in the CVS outlet streams. Use of the existing CTO would require a compressor (much more costly than a fan/blower) to provide the pressure required to route the CVS outlet streams to the HPVGTS.

Energy Impact Analysis

The feasible control options were evaluated for energy impacts, and it was determined that no unusual energy impacts exist beyond what was included in the economic impact analysis. It was also determined that the various control options do not result in any energy benefits for BPCR.

Environmental Impact Analysis

BPCR has stated that all of the technically feasible control options, except the Biofiltration option, have adverse impacts; however, the BAQ disagrees, as these impacts are considered normal consequences of operating these control technologies. Operation of the combustion control technologies would create more GHG, CO, and NOx. Operation of the CTO requires disposal of spent catalyst, which may be considered hazardous waste.

Step 5: Select BACT Controls and Limits

Because none of the control options were deemed feasible, a CO limit, along with monitoring, recordkeeping, and reporting was set as BACT. Using the uncontrolled emissions of the CVS, the CO limit for the #1 and #2 PTA CVS has been determined to be 24.0 lb/hr and 20.0 lb/hr, respectively. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR will be required to calculate and maintain hourly CO emissions. Hourly CO emissions shall be calculated on a 30-day rolling average. Reports of the calculated values shall be submitted semiannually, shall be maintained on site for a period of at least 5 years.

A source test to determine CO emission rates from each CVS is required within 180 days after startup, and every 3 years thereafter.

E.I. BACT for VOC and CO from #2 OX Unit HPVGTS Fired Heater

The #2 OX Unit HPVGTS Fired Heater preheats the waste gas feed stream to the #2 HPVGTS through indirect heat exchange. The VOC and CO emission are from combustion of natural gas fuel in the Fired Heater. The Fired Heater has a single burner that has a nominal rating of 15 MM BTU/hr, but actually operates less than 3 MM BTU/hr on average per year. The VOC and CO PTE from the Fired Heater is 0.4 and 5.4 tpy, respectively.

Step 1: Identify All Available Control Technologies

The following control technologies were found to reduce VOC and CO emissions from this type of source:

- Good Combustion Practices – Good combustion practices for the Fired Heater is to maintain good air/fuel mixture in the combustion zone.
- Flue Gas Recirculation (FGR) – FGR is a method of reducing NOx emissions, by taking some of the re-circulated flue gas and mixing with combustion air. This mixture decreases the flame temperature and the availability of oxygen, thereby reducing the formation of thermal NOx.
- Natural Gas Fuel
- Tune-ups

Step 2: Technical Feasibility of Options

The use of FGR is not technically feasible since it is not compatible with the existing heater. The remaining control options are technically feasible since they all are successfully used on heaters.

Step 3: Ranking of Control Technologies by Control Effectiveness

The technically feasible control options are work practices and cannot be ranked.

Step 4: Evaluation of Most Effective Controls

This step of the BACT analysis evaluates energy, environmental, and economic impacts of all the feasible control technologies. BPCR decided to use the economic impacts first, then energy and environmental impacts to determine BACT for the affected sources. The following table is a summary of the effectiveness of the control options.

Economic Impact Analysis

The use of natural gas, tune-ups, and good combustion practices are currently being used, so there are no associated economic impacts. Use of these control options is economically feasible, as they save money by increasing energy efficiency.

Energy Impact Analysis
The feasible control options were evaluated for energy impacts, and it was determined that no unusual energy impacts exist. It was determined that the tune-ups and good combustion practices result in any energy benefits for BPCR, due to increase energy efficiency.

Environmental Impact Analysis
The feasible control options have some environmental benefit due to reduction in energy usage, which lowers emissions of combustion pollutants such as GHG, CO, and NOx.

Step 5: Select BACT Controls and Limits

BACT for the Fired Heater has been determined to be the sole use of natural gas, annual tune-ups, and good combustion practices. Using the AP-42 emission factors for natural gas combustion of 5.5 lb/MM SCF for VOC and 84 lb/MM SCF for CO, and a heat content of 1000 BTU/SCF; the VOC limit has been determined to be 0.0055 lb/MM BTU, and the CO limit has been determined to be 0.084 lb/MM BTU, each based on a 3-hour block average. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR is required to monitor and record natural gas fuel usage on a monthly basis. Records of natural gas usage shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years.

BPCR is required to develop a tune-up plan and perform tune-ups on this source, once every 13 months. The tune-up plan will be developed in accordance with manufacturer's specifications or with good engineering practices. Records of tune-ups shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years. The tune-up plan shall only be included in the initial report. Subsequent submittals of the tune-up plan are required within 30 days of the change if the plan is modified or the Department requests additional information.

BPCR is required to implement good combustion practice(s) on this source, by maintaining proper air/fuel mixture in the combustion zone by holding excess oxygen between 3.5 and 12%. Percent (%) excess oxygen shall be monitored continuously with a daily average, which means that at least one data point shall be measured every 15-minute period, within a 24-hour block period (midnight to midnight), and shall be averaged together for a daily reading. Records of hourly block averages of monitored parameters shall be maintained on site for a period of at least 5 years. Records of excursions of monitored parameters shall be submitted semi-annually. If no excursions occurred during the reporting period then a letter shall be submitted to the Department indicating such. An excursion shall be deemed to have occurred if either of the following are met:

- The daily average for a parameter is outside the approved monitoring range.

- The number of valid 15-minute monitoring periods for a given parameter is less than 75 percent of the number of process operating periods in a 24-hour day.

F.**J.** BACT for VOC and CO from #1 OX Unit Emergency Generators

The #1 OX Unit will have installed two new emergency generators for this project (the BM-1201 Emergency Generator replacement and the new BM-1204 Emergency Generator). Both generators will be fired with diesel fuel, and will be subject to 40 CFR 60, Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines". The generators will be required to meet Tier 3 emission standards and will be limited to operating no more than 100 hours per year on a non-emergency basis. The 100 hours per year limit and the Tier 3 emission standards will make emissions of VOC (0.003 tpy) and CO (0.03 tpy) minimal. Therefore, a full BACT analysis was not performed on these two generators. The proposed BACT limit for each generator will be an operational restriction of no more than 100 hours per year of non-emergency use, compliance with Tier 3 emission standards, and the burning of only ultra low diesel as fuel. These limits shall apply at all times including during startup, shutdown, and malfunction.

BPCR is required to record the actual operating hours of each generator on a monthly basis. Reports of the recorded hours of operation shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years.

BPCR is required to monitor and record diesel fuel usage on a monthly basis. Fuel oil supplier certification shall be obtained for each batch of oil received and stored on site. Records of diesel fuel usage and reports of the recorded sulfur content shall be submitted semiannually, and shall be maintained on site for a period of at least 5 years.

G.**K.** Summary of BACT Limits

Table V.K-1: Summary of BACT Limits

Process/Equipment	Pollutant	BACT Limit	Control Method
#1 OX High Pressure Absorber	VOC	4.70 lb/hr	CTO
	CO	87.972.0 lb/hr	CTO
#1 OX Low Pressure Absorber	VOC	9.60 lb/hr	N/A
	CO	4.1014.0 lb/hr	N/A
#1 OX Fugitives	VOC	HON LDAR	HON LDAR
#1 PTA Crystallizer Vents	VOC	20.0	N/A
	CO	24.0	N/A
#2 OX High Pressure Absorber	VOC	3.50	CTO
	CO	75.0	CTO
#2 OX Low Pressure Absorber	VOC	8.85	N/A
	CO	3.50	N/A
#2 OX Fugitives	VOC	HON LDAR	HON LDAR
#2 PTA Crystallizer Vents	VOC	20.0	N/A

Table V.K-1: Summary of BACT Limits			
Process/Equipment	**Pollutant**	**BACT Limit**	**Control Method**
	CO	20.0	N/A
#2 OX HPVGTS Fired Heater	VOC	0.0055 lbs/MM BTU	Good Combustion Practices, Natural Gas as sole fuel, Tune-ups
	CO	0.084 lbs/MM BTU	
#1 OX New Emergency Generators	VOC	100 hours per year non-emergency use, Tier 3 emission standards, and use of only ultra low sulfur (15 ppm) diesel fuel	N/A
	CO		

VI. Air Quality Impact Analysis

For a major facility, PSD regulations require an applicant to analyze the impact from the construction of a proposed new source(s) on the following areas:

1. Compliance with the National Ambient Air Quality Standards (NAAQS);
2. Compliance with the PSD Increments;
3. Significant impact on PSD Class I Areas, including Class I PSD increments;
4. Impairments to visibility, soil, and vegetation; and
5. Air Quality impact of general growth associated with the source.

All minor and major sources proposing new construction or construction modifications in South Carolina (SC) are also required to demonstrate that their facility will remain in compliance with South Carolina Regulation 61-62.5 Standards 2 (AAQS), and 7 (Class II PSD Increments).

General results of this compliance demonstration indicate that there will be no exceedances of PSD Class II SILs or South Carolina ambient air quality standards PSD increments. Since this project was below the AQRV threshold, no refined Class I modeling was performed

All minor and major sources proposing new construction are also required to demonstrate compliance with South Carolina Regulation 61-62.5 Standard No. 8 (toxics) unless otherwise exempt. All emissions of toxic air pollutants from the proposed facility will be emitted from sources which will be in compliance with a Maximum Achievable Control Technology (MACT) standard at startup and/or are the product of the burning of virgin fuel. As such, the proposed facility is exempt from the requirements of Standard 8 and no modeling is required for this standard.

A. PSD Class II Modeling Analysis

The PSD Review requires pollutants, which are determined to be “major”, be evaluated by an Air Quality Impact Analysis and Additional Impacts Analysis. The Air Quality Impact Analysis consists of (1) a Preliminary Modeling Analysis to determine which pollutants from the proposed project at the facility only**,** exceed their Class II Significant Impact Levels (SIL); and (2) a more comprehensive Full Impact Analysis based on concentrations of pollutants that exceed the SIL for the facility and additional ‘facility-wide’ impacts from other facilities that may impact the Significant Impact Area (SIA). The Additional Impacts Analysis evaluates the impacts on soils, vegetation, and visibility effects.

A.1. PSD CLASS II PRELIMINARY MODELING ANALYSIS

Potential emission rates or net emission rate increases for each pollutant determined to be significant (Table IV-1.) at the facility were modeled to determine (a) the Significant Impact Level (SIL); and (b) whether or not the facility may be exempted from the ambient monitoring data requirements. Each of these three preliminary Class II analyses is discussed below.

A.1.a. SIGNIFICANT IMPACT LEVEL (SIL) ANALYSIS

If an impact is less than the SIL, then no further PSD analysis is required. Table VI-1 provides the results of the SIL modeling analysis for this project for the “major” pollutants as defined above. Maximum concentrations are used for the Significant Impact Level analysis (i.e. Highest-First-High). This analysis, which shows SILs were not exceeded for CO for the averaging periods indicated. Therefore, a Full Impact analysis was not required for this pollutant. No further PSD analysis is required for CO; however, CO must be included in the facility-only South Carolina Standard 2 modeling.

TABLE VI-1. CLASS II PREVENTION OF SIGNIFICANT DETERIORATION (PSD) SIGNIFICANT IMPACT LEVEL

POLLUTANT	AVERAGING TIME	MODEL USED	MAXIMUM IMPACT ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Exceeds SIL (Yes/No)	SIGNIFICANT IMPACT AREA (km)
CO	1 HOUR	AERMOD	217	2000	No	N/A
	8 HOUR	AERMOD	83	500	No	N/A
Ozone is not modeled, but a general impact assessment is to be made if the source is major for ozone as determined in Table IV-1.						
Maximum concentrations are used for the Significant Impact Level analysis (i.e. Highest-First-High).						

It should be noted that while source BT-702 shows an offset emission source with a negative emission rate for #1 OX DHT Overhead Scrubber (BT-702), this source would have operated at that rate only sporadically. Consequently, the results shown in Table VI.1 include the stacks with the positive emissions rates. These predicted values are below the PSD significant impact thresholds of 2,000 μg/m3 (1-hour) and 500 μg/m3 (8-hours). Therefore, no further modeling analysis is required for CO.

Analysis for Volatile Organic Compound Impact

No air quality model exists that can evaluate the air quality impact of a point source of VOC emissions on area-wide ozone concentrations. This project was evaluated using a project related net increase in VOC emissions of 164.4 TPY. The estimated increase in emissions of NO_X is below the PSD significant emission increase threshold.

The area measured values of ozone in the Charleston area for the last 3 years are listed below.

- Bushy Park Monitor # 45015002
  - 8-hour average 4th high – 0.061 ppm, 0.065 ppm, 0.066 ppm (2012, 2011, 2010)
- Cape Romain # 450190046
  - 8-hour average 4th high – 0.064 ppm, 0.066 ppm, 0.068 ppm (2012, 2011, 2010)

The National Ambient Air Quality Standard (NAAQS) for ozone is 0.075 ppm. The monitored values above show the area to be well in attainment of the 8-hour ozone NAAQS.

The VOC impact was based on the project having an increase in VOC emissions of 164.4 TPY and less than 40 TPY of NO_X emissions. The Southeastern United States, including South

Carolina, is NO_X limited with regards to ozone formation. This means that there is an excess of VOC in the atmosphere with regards to ozone formation and increases in VOC do not lead to increases in ozone production. The excess VOC is in part due to natural sources in the environment. Due to the excess VOC, only increases in NO_X in this region are a concern with regards to ozone formation. This project does not result in a significant increase in NO_X emissions so it would be expected that the project as a whole would have minimal impact on area ozone concentrations. Ambient impacts from NO_X are addressed in NO_X modeling.

To better assess the relative nature of the project increase in VOC emissions, average actual VOC emissions for the Charleston County and three other surrounding Counties are presented below.

COUNTY 3-YEAR AVERAGE ACTUAL VOC EMISSIONS (TPY)

- Charleston 1,430
- Berkeley 1,625
- Dorchester 470
- Colleton 857
- Total for Area 4,382

The project VOC emissions impact was based on an estimated VOC emissions increase of 164.4 TPY from this project. This value represents 3.8 percent of the actual area-wide point source emissions of VOCs. Note that this total does not include mobile sources or emissions from minor sources in the area.

Because project emission level increases for VOCs for this project are relatively small and the project does not have a significant increase in NO_X emissions (recall the area is NO_X limited with respect to the formation of ozone), it is concluded this project would not cause or contribute to a violation of the NAAQS for ozone.

A.1.b. SIGNIFICANT IMPACT AREA (SIA) ANALYSIS

The impact area is a circular area with a radius extending from the source to (1) the most distant point where approved dispersion modeling predicts a significant ambient impact will occur (greater than or equal to the SIL), or (2) a modeling receptor distance of 50 km, whichever is less. An impact area is initially established for each pollutant for every averaging time. Sources within the SIA will be used for this analysis.

Since no pollutant concentrations exceeded their respective SILs, this project is not subject to the SIA analysis.

A.1.c. SIGNIFICANT MONITORING CONCENTRATION ANALYSIS

Modeling significance results for PM_{10}, SO_2, NO_2, and CO are shown below along with significant monitoring concentrations for these pollutants. The significant monitoring concentrations are from SC Regulation 61-62.5, Standard No. 7. Impacts are the maximum modeled concentrations for each pollutant (i.e. Highest First High).

TABLE VI-2. SIGNIFICANT MONITORING CONCENTRATIONS				
Pollutant	Averaging Period	Max. Impact ($\mu g/m^3$)	Significant Monitoring Concentration ($\mu g/m^3$)	Exceeds (Y or N)
CO	8-Hour	83	575	N0

The maximum impacts for CO are below the significant monitoring concentration (SMC) levels, therefore, no pre-construction monitoring is required for these pollutants.

Since this site is significant for VOCs, ozone monitoring data also needs to be reviewed. Section 2.4 of U.S. EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007) permits the use of existing representative air quality data in place of preconstruction monitoring data, provided the monitor location, how current the data is, and the quality of data are acceptable.

The nearest regional monitor for the BP Amoco – Cooper River Plant for CO is located at the Cape Romain station. Since the Cape Romain CO monitor is located in a Class I area on the coast of South Carolina and may not be entirely representative of a more inland, rural area, an alternative monitoring location was sought. The only other candidate site for CO background data in South Carolina is the Greenville County Health Department monitoring station. While this monitoring station is located over 270 km from the project facility, it is in a major urban area with significant CO emissions and is a very conservative alternative that easily satisfies the background monitoring requirements.

These monitors are operated by the SC DHEC in support of National Ambient Air Quality Standards attainment activities and meet the quality assurance requirements for this work. These activities require the data to be quality assured, and the level of quality assurance for these monitors meets the requirements for PSD modeling.

Therefore, it has been determined that the data DHEC has obtained for background concentrations are representative of the ambient pollutant concentrations in the area of the proposed facility. In accordance with Chapter C, Section III of the New Source Review Manual (Draft document, dated October 1990), the Bureau approves the use of ambient data collected at DHEC monitoring stations for pre-construction monitoring requirements.

A.2. PSD CLASS II FULL IMPACT MODELING ANALYSIS

A Full Impact Analysis is required for any pollutant for which the proposed source's estimated ambient pollutant concentrations meet or exceed the SIL's (determined in Table VI-1). Separate analyses are performed for determining compliance with the NAAQS and PSD increments. The NAAQS analysis must also include background pollutant concentrations. The Full Impact Analysis consists of modeling all facilities within the SIA, and those in the SA, which are not excluded by the screening protocol. The SA used is an area extending 50 km beyond the SIA for each pollutant and averaging period.

Since no pollutant concentrations exceeded the respective SILs, this project is not subject to Full Impact Modeling.

B. Additional Impacts Analysis – Growth, Soils and Vegetation, and Visibility Impairment

PSD review requires an analysis of any potential impairment to visibility, soils, and vegetation that may occur as a result of the proposed or modified facility/sources. The review also requires an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the expansion.

B.1. Growth

The SC PSD rules require the applicant to provide information relating to the nature and extent of air quality impacts from all commercial, residential, industrial and other growth, which has occurred since August 7, 1977, in the area the facility, or modification, would affect. For the purposes of this report, the area the facility would affect is defined as the area of significant impact. Since this project does not require development of a significant impact area, and the proposed modification at the facility is not anticipated to result in any significant increase in full-time employment (an associated increase in traffic flow) at the facility. The construction activity related to the project may require a temporary increase in local traffic due to construction related jobs and associated traffic, but the construction and modification of the facility and any workforce growth associated residential and commercial growth is not expected to cause or contribute a quantifiable adverse impact on local ambient air quality.

B.2. Soils and Vegetation

Maximum predicted offsite impacts (highest first high) were compared to EPA screening levels or secondary NAAQS. CO at the predicted levels of concentration for this project does not have any known effects on soils or vegetation. Consequently, no effects on soils or vegetation would be expected from the project.

Table VI-3. SOILS AND VEGETATION ANALYSIS

Pollutant	Averaging Time	Model Used	MAX. Impact (µg/m^3)	Back-ground (µg/m^3)	Facility / Regional Impact (µg/m^3) (2)	EPA Screening Concentration (µg/m^3)	AAQS Standard (µg/m^3)	Exceeds?
CO	1 Week (4)	AERMOD	83 (1)	745.4	815	1,800,000	N/A	No

1) Concentrations include only the facility impacts since they either did not exceed the Significant Impact Levels or none were available. All other values include full impact sources.

2) Results include background values when available.

3) Non-Standard Averaging period was conservatively estimated as follows:
1 Week CO = 8-hour concentration compared to weekly standard. Background is also 8-hr value.

B.3. Visibility

This visibility impairment analysis is distinct from the Class I visibility impact analysis. VISCREEN can be used following the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015, 1988). The procedure consists of a screening process done through several levels. A nearby sensitive receptor, such as a state park or local airport, is analyzed to determine if an impact is expected.

This project triggers PSD air quality evaluation requirements for CO and VOCs only. Neither of these pollutants is typically understood to affect visibility so no visibility impairment assessment is needed or was undertaken (i.e. the VISCREEN model used for visibility analysis does not have inputs for CO or VOC).

C. PSD Class I Impact Analysis

A facility within 100 km of a Class I area must perform Class I modeling to determine the impact on the Class I area. For the visibility and deposition analyses, the recommendations in the; 1) *Interagency Workgroup on Air Quality Modeling Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts (IWAQM)* (EPA-454/R-98-019, December 1998); 2) *Federal Land Managers' Air Quality Related Values Workgroup Phase I Report (FLAG 2010)* (U.S. Forest Service- Air Quality Program, the National Park Service – Air Resources Division, and the U.S. Fish & Wildlife Service – Air Quality Branch, December 2000); 3) *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology* (U.S. EPA, June 15, 2005); and 4) U.S. EPA's *Guidelines on Air Quality Models (Guideline)*, are to be followed.

The 2010 FLAG document allows the screening of sources based on total emissions of certain pollutants and distance from the source to the Class I area. When a source is screened out with Q/D ≤ 10 (where D = distance from the source to the Class I area in kilometers; Q = TPY of SO2 + NOx + PM10 + H2SO4), the facility is not required to do an AQRV analysis. Additional information provided in public comment responses clarified that for modified sources, applicants should only consider the emissions increases associated with the proposed project modification when calculating Q/D.

For this project, the source was below the screening level and no AQRV analysis was required. [Q/D = 1.6 ≤ 10 where D = 21.6 kilometers and Q = 34.6 TPY (SO2 = 0.2, NOx = 27.8, PM10 = 6.6, and H2SO4 = 0)] [NOTE: These values were updated based in the July 2014 application. The initial FLM evaluation was based on the April 2013 application which had a Q/D value of 1.5. Both are still well below the screening value of 10]

C.1. CLASS I VISIBILITY ANALYSIS

This project triggers PSD air quality evaluation requirements for CO and VOCs only. Neither of these pollutants is typically understood to affect visibility so no visibility impairment assessment is needed or was undertaken (i.e. the VISCREEN model used for visibility analysis does not have inputs for CO or VOC).

C.4. CLASS I DEPOSITION ANALYSIS

Since the facility screened out of the Class I AQRV analysis based on their Q/D calculation, and since there were no sulfate or nitrate emissions above the triggering threshold for the PSD review, analyses for visibility and deposition are not required.

D. South Carolina Facility-wide Compliance Demonstration

All minor and major sources proposing new construction or construction modifications in South Carolina are required to demonstrate compliance with South Carolina Regulation No. 62.5 Standards Nos. 2 (NAAQS), 7 (Class II PSD Increment), and 8 (Air Toxics). Standard No. 7 (PSD) Part k - "Source Impact Analysis" and Part p - "Sources Impacting Federal Class I Areas - Additional Requirements" require Class II modeling. Facility-wide emissions from the facility only were modeled to demonstrate compliance with Standards 2, 7, and 8.

Table VI-4. STANDARD NO. 2 - AMBIENT AIR QUALITY STANDARDS MODELING ANALYSIS

Pollutant	Averaging Time	Model Used	Maximum Modeled Concentration (μg/m³) (1)	Background Concentration (μg/m³)	Total (μg/m³)	Standard (μg/m³)	% of Standard
PM_{10}	24 Hour	ISCST3	29.3	38	67	150	45
$PM_{2.5}$	24 Hour	n/a	(2)	--	(2)	35	--
	Annual	n/a	(2)	--	(2)	15	--
SO_2	3 Hour	ISCST3	138.1	130.9	269	1300	21
	24 Hour	ISCST3	49.4	18.3	68	365	19
	Annual	ISCST3	5.8	4.7	11	80	14
NO_2	Annual	ISCST3	20.0	19.0	39	100	39
CO	1 Hour	AERMOD	**217**	**1870**	**2087**	40,000	5
	8 Hour	AERMOD	**83**	**1374**	**1457**	10,000	15

1) The highest-first-high modeled concentration was used for annual averaging periods and the highest-second-high was used for all other averaging periods, except where noted otherwise.

2) The PM10 surrogate was used to demonstrate compliance with the PM2.5 standards.

9/30/2014 - PSD SIL modeling for CO was based only on project emissions which are the new potentials for the sources affected by this project. The other sources not part of this project are all exempt for CO, so the PSD modeling is the new State modeling. Some of the revised sources are also below the 10 lb/hr exemption threshold, but were included with the project modeling.

Table VI-5. BACKGROUND MONITORING DATA (μg/m³)

Pollutant	Site Name	County	Year	1-Hr	3-Hr	8-Hr	24-Hr	3-Mo	Annual
PM_{10}	Cape Romain	Charleston	2005				38		
SO_2	Cape Romain	Charleston	2005		130.9		18.3		4.7
NO_2	Jenkins Ave Fire Sta	Charleston	2005						19.0

Table VI-5. BACKGROUND MONITORING DATA (μg/m³)									
Pollutant	**Site Name**	**County**	**Year**	**1-Hr**	**3-Hr**	**8-Hr**	**24-Hr**	**3-Mo**	**Annual**
CO	**Greenville CHD**	**Greenville**	**10-12**	**1870**		**1374**			

PM10 24-hr is the fourth-high over three year period.
Annual for pollutants other than PM2.5 is the average of the annual averages over the three year period.
All other averaging periods are the average of the three year second-high values.

Table VI-6. STANDARD NO. 7 - CLASS II PSD MODELING ANALYSIS					
Pollutant	Averaging Time	Model Used	Maximum Modeled Concentration (μg/m³) (1)	Standard (μg/m³)	% of Standard
PM_{10}	24 Hour	ISCST3	6	30	20
	Annual	ISCST3	1	17	6
SO_2	3 Hour	ISCST3	70	512	14
	24 Hour	ISCST3	25	91	27
	Annual	ISCST3	0	20	0
NO_2	Annual	ISCST3	4	25	16

1) The highest-first-high modeled concentration was used for annual averaging periods and the highest-second-high was used for all other averaging periods.

Since the OX and PTA processes at the facility are subject to the Hazardous Organic NESHAPS MACT, the residual risk analysis has been completed, and will be required to be in compliance with this regulation upon startup of the proposed project, the process is exempt from Standard 8 modeling requirements. Additionally, all sources that emit air toxics at the facility have been determined to be controlled by the HON. Therefore, all Standard 8 modeling has been removed from the summary.

For a major facility, PSD regulations require an applicant to analyze the impact from the construction of a proposed new source(s) on the following areas:

1. Compliance with the National Ambient Air Quality Standards (NAAQS);
2. Compliance with the PSD Increments;
3. Significant impact on PSD Class I Areas, including Class I PSD increments;
4. Impairments to visibility, soil, and vegetation; and
5. Air Quality impact of general growth associated with the source.

All major sources proposing new construction or construction modifications in South Carolina (SC) are also required to demonstrate that their facility will remain in compliance with South Carolina Regulation 61-62.5 Standards 2 (AAQS), 7 (Class II PSD Increments) and 8 (Air Toxics).

General results of this compliance demonstration indicate that there will be no exceedances of

NAAQS, South Carolina ambient air quality standards, or PSD increments. The proposed project is also not expected to cause any impairment in the vicinity of the facility to visibility, soils, and vegetation nor is any general commercial, residential, industrial, and other growth associated with the expansion expected to cause or contribute to a quantifiable adverse impact on local ambient air quality. In addition, there will also be no adverse effects on visibility, vegetation, or soils in any of the Class I areas within 300 km of the facility/source.

A. PSD Class II Modeling Analysis

The PSD review requires pollutants, which are determined to be "major," to be evaluated by an Air Quality Impact Analysis and Additional Impacts Analysis. The Air Quality Impact Analysis consists of: 1) a Preliminary Modeling Analysis to determine which pollutants from the proposed project, at the facility only, exceed their Class II Significant Impact Levels (SIL); and 2) for each pollutant that exceeds its SIL, a Full Impact Analysis that includes emissions from the facility, and those from nearby facilities that may cause an impact in the Significant Impact Area (SIA). The Additional Impacts Analysis evaluates the impacts on soils, vegetation, and visibility.

A.1. PSD Class II Preliminary Modeling Analysis

Potential emission rates or net emission rate increases, for each pollutant determined to be significant (Table A.1) at the facility, were modeled to determine: a) impacts relative to the Significant Impact Level (SIL); b) the impact area within which a Full Impact Analysis must be performed (if applicable); and c) whether or not the facility may be exempted from the ambient monitoring data requirements. Each of these three preliminary Class II analyses are discussed below.

A.1.a. Significant Impact Level (SIL) Analysis

If a modeled impact is less than or equal to the SIL, then no further PSD analysis is required. Table ~~B.1~~ VI-1provides the results of the SIL modeling analysis for this project for the "major" pollutants as defined above (the impacts are the maximum modeled concentrations as noted in the table). Results are reported from the BAQ analysis. This analysis shows the SIL was not exceeded for CO for each respective averaging period. Therefore, no further PSD analysis is required for CO; however, CO must be included in the Standard 2 (facility-only) compliance analysis (Section E).

TABLE VI-1. CLASS II PREVENTION OF SIGNIFICANT DETERIORATION (PSD) SIGNIFICANT IMPACT LEVEL

POLLUTANT	AVERAGING TIME	MODEL USED	MAXIMUM IMPACT (μg/m^3)	SIL (μg/m^3)	Exceeds SIL? (Yes/No)	SIGNIFICANT IMPACT AREA (km)
CO	1 HOUR	AERMOD	243	2000	No	N/A
	8 HOUR	AERMOD	120	500	No	N/A

TABLE VI-1. CLASS II PREVENTION OF SIGNIFICANT DETERIORATION (PSD) SIGNIFICANT IMPACT LEVEL						
POLLUTANT	AVERAGING TIME	MODEL USED	MAXIMUM IMPACT (μg/m^3)	SIL (μg/m^3)	Exceeds SIL? (Yes/No)	SIGNIFICANT IMPACT AREA (km)
Maximum concentrations are used for the Significant Impact Level analysis (i.e. Highest-First-High).						

It should be noted that while the DHT Overhead Scrubber (BT-702) is an offset emission source with a negative emission rate, this source would have operated at the previously estimated rate only sporadically. Consequently, the results shown in Table VI-1only include the stacks with positive emissions rates. These predicted values are below the PSD significant impact thresholds of 2,000 μg/m3 (1-hour) and 500 μg/m3 (8-hours). Therefore, no further modeling analysis is required for CO.

Analysis for Volatile Organic Compound Impact

For the VOC emissions increases, this project was evaluated using a project related net increase in VOC emissions of 164.4 TPY. The estimated increase in emissions of NO_X is below the PSD significant emission increase threshold.

The area measured values of ozone in the Charleston area for the last 3 years are listed below.

- Bushy Park Monitor # 45015002
    - 8-hour average 4th high – 0.061 ppm, 0.065 ppm, 0.066 ppm (2012, 2011, 2010)
- Cape Romain # 450190046
    - 8-hour average 4th high – 0.064 ppm, 0.066 ppm, 0.068 ppm (2012, 2011, 2010)

The National Ambient Air Quality Standard (NAAQS) for ozone is 0.075 ppm. The monitored values above show the area to be well in attainment of the 8-hour ozone NAAQS.

The VOC impact was based on the project having an increase in VOC emissions of 164.4 TPY and less than 40 TPY of NO_X emissions. The Southeastern United States, including South Carolina, is NO_X limited with regards to ozone formation. This means that there is an excess of VOC in the atmosphere with regards to ozone formation and increases in VOC do not lead to increases in ozone production. The excess VOC is in part due to natural sources in the environment. Due to the excess VOC, only increases in NO_X in this region are a concern with regards to ozone formation. This project does not result in a significant increase in NO_X emissions so it would be expected that the project as a whole would have minimal impact on area ozone concentrations. Ambient impacts from NO_X are addressed in NO_X modeling.

To better assess the relative nature of the project increase in VOC emissions, average actual VOC emissions for the Charleston County and three other surrounding Counties are presented below.

COUNTY 3-YEAR AVERAGE ACTUAL VOC EMISSIONS (TPY)

- Charleston 1,430
- Berkeley 1,625
- Dorchester 470
- Colleton 857
- Total for Area 4,382

The project VOC emissions impact was based on an estimated VOC emissions increase of 164.4 TPY from this project. This value represents 3.8 percent of the actual area-wide point source emissions of VOCs. Note that this total does not include mobile sources or emissions from minor sources in the area.

Because project emission level increases for VOCs for this project are relatively small and the project does not have a significant increase in NO_X emissions (recall the area is NO_X limited with respect to the formation of ozone), it is concluded this project would not cause or contribute to a violation of the NAAQS for ozone.

A.1.b. Significant Impact Area (SIA) Analysis

The SIA is a circular area with a radius extending from the source to the lesser of: 1) the most distant point where the Preliminary Modeling Analysis predicts a significant ambient impact will occur (greater than the SIL), or 2) a modeling receptor distance of 50 km. The SIA will contain the receptor field and additional sources to be used in the Full Impact Analysis (sources in the Screening Area (SA) will also be included, as appropriate).

Since no pollutant concentrations exceeded their respective SILs, this project is not subject to the SIA analysis.

A.1.c. Significant Monitoring Concentration Analysis

Modeling significance results (impacts) for CO are shown below along with significant monitoring concentrations (SMC) for these pollutants. The impacts are the maximum modeled concentrations as noted in the table. The significant monitoring concentrations are from SC Regulation 61-62.5, Standard 7.

TABLE VI-2. SIGNIFICANT MONITORING CONCENTRATIONS

Pollutant	Averaging Period	Max. Impact ($\mu g/m^3$)(1)	Significant Monitoring Concentration ($\mu g/m^3$)	Exceeds (Y or N)
CO	8-Hour	120	575	NO

1) Highest-first-high concentration

The maximum impacts for CO are below the significant monitoring concentration (SMC) levels;

therefore, no pre-construction monitoring is required for this pollutant.

Since this project is significant for VOCs, ozone monitoring data also needs to be reviewed. Section 2.4 of U.S. EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007) permits the use of existing representative air quality data in place of preconstruction monitoring data, provided the monitor location, how current the data is, and the quality of data are acceptable.

The nearest regional monitors for the BP Amoco – Cooper River Plant for ozone are the Cape Romain and Bushy Park stations as previously discussed. The Cape Romain station is located approximately 30 km from the BP Amoco facility and the Bushy Park station is located approximately 7 km from the BP Amoco facility. Both stations are representative of the ambient ozone background concentrations at the BP Amoco facility and, as previously indicated, data from both stations indicate this area is in attainment for the ozone NAAQS.

These monitors are operated by the SC DHEC in support of National Ambient Air Quality Standards attainment activities and meet the quality assurance requirements for this work. These activities require the data to be quality assured, and the level of quality assurance for these monitors meets the requirements for PSD modeling.

Therefore, it has been determined that the data DHEC has obtained for background concentrations are representative of the ambient pollutant concentrations in the area of the proposed facility. In accordance with Chapter C, Section III of the New Source Review Manual (Draft document, dated October 1990), the Bureau approves the use of ambient data collected at DHEC monitoring stations for pre-construction monitoring requirements.

A.2. PSD Class II Full Impact Modeling Analysis

A Full Impact Analysis is required for any pollutant for which the proposed source's estimated (modeled) ambient pollutant concentrations exceed the SIL (determined in Table VI-1).

Since no pollutant concentrations exceeded the respective SILs, this project is not subject to Full Impact Modeling.

B. Additional Impacts Analysis

PSD review requires an analysis of any potential impairment to visibility, soils, and vegetation that may occur as a result of the proposed or modified facility/sources. The review also requires an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the expansion.

B.1. Growth

The SC PSD rules require the applicant to provide information relating to the nature and extent of air quality impacts from all commercial, residential, industrial and other growth in the area the facility, or modification, would affect. For the purposes of this report, the area the facility would affect is defined as the area of significant impact. This project does not require development of a significant impact area, and the proposed modification at the facility is not anticipated to result in any significant increase in full-time employment (or an associated increase in traffic flow) at the facility. Nor is there any construction activity related to the project that would result in a temporary increase in local traffic. Therefore, the construction and modification of the facility and any workforce-associated residential and commercial growth is not expected to cause or contribute to a quantifiable adverse impact on local ambient air quality.

B.2. Soils and Vegetation

Maximum predicted offsite impacts were compared to EPA screening levels or secondary NAAQS. Modeling of all the proposed emissions for the soils and vegetation analysis indicates that there will be no adverse impacts expected on soils or vegetation caused by the proposed facility emissions.

Table VI-3. SOILS AND VEGETATION ANALYSIS

Pollutant	Averaging Time	Model Used	MAX. Impact (μg/m^3)$^{(1)}$	Back-ground (μg/m^3)	Facility / Regional Impact (μg/m^3)$^{(2)}$	EPA Screening Concentration (μg/m^3)	AAQS Standard (μg/m^3)	Exceeds?
CO	1 Week $^{(3)}$	AERMOD	120$^{(4)}$	916	1036	1,800,000	N/A	No

1) All values, unless noted otherwise, are the highest-first-high modeled concentration and include full impact sources.

2) Results include background values when available.

3) Non-Standard Averaging period was conservatively estimated as follows:
- CO 1-Week = 8-hour concentration compared to weekly standard. Background is also 8-hr value.

4) Concentration includes only the facility impact since the concentration either did not exceed the Significant Impact Level (SIL) or no SIL was available.

B.3. Visibility

This visibility impairment analysis is distinct from the Class I visibility impact analysis. VISCREEN can be used following the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015, 1988). The procedure consists of a screening process done through several levels. A nearby sensitive receptor, such as a state park or local airport, is analyzed to determine if an impact is expected.

This project triggers PSD air quality evaluation requirements for CO and VOCs only. Neither of these pollutants is typically understood to affect visibility so no visibility impairment assessment is needed or was undertaken (i.e. the VISCREEN model used for visibility analysis does not have inputs for CO or VOC).

C. PSD Class I Impact Analysis

A facility within 300 km of a Class I area must address the impact on the Class I area. For the visibility and deposition analyses, the recommendations in the following should be consulted: 1) *Interagency Workgroup on Air Quality Modeling Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts (IWAQM)* (EPA-454/R-98-019, December 1998); 2) *Federal Land Managers' Air Quality Related Values Workgroup Phase I Report (FLAG 2010)* (U.S. Forest Service- Air Quality Program, the National Park Service – Air Resources Division, and the U.S. Fish & Wildlife Service – Air Quality Branch, December 2000); 3) *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology* (EPA, June 15, 2005); and 4) EPA's *Guidelines on Air Quality Models (Guideline)*.

C.1. Class I Increment Consumption Impact Analysis

This analysis is not required since there are no increments for CO or VOCs.

C.2. Class I Visibility Analysis

This project triggers PSD air quality evaluation requirements for CO and VOCs only. Neither of these pollutants is typically understood to affect visibility so no visibility impairment assessment is needed or was undertaken (i.e. the VISCREEN model used for visibility analysis does not have inputs for CO or VOC).

C.3. Class I Deposition Analysis

This project triggers PSD air quality evaluation requirements for CO and VOCs only. These pollutants are not pollutants of concern related to soil or surface water deposition, so no deposition assessment is needed.

D. South Carolina Facility-wide Compliance Demonstration

All major sources proposing new construction or construction modifications in South Carolina are required to demonstrate compliance with South Carolina Regulation No. 62.5 Standards 2 (NAAQS), 7 (Class II PSD Increment), and 8 (Air Toxics) [Standard 7 (PSD) Part k - "Source Impact Analysis" and Part p - "Sources Impacting Federal Class I Areas - Additional Requirements" were addressed in Sections B and D above, as appropriate].

Facility-wide emissions from the facility only were considered to demonstrate compliance with Standard 2, 7 and 8, the results of which are shown in the tables below.

Table VI-4. STANDARD NO. 2 - AMBIENT AIR QUALITY STANDARDS MODELING ANALYSIS

Pollutant	Averaging Time	Basis	Maximum Concentration (µg/m^3)(1)	Background Concentration (µg/m^3)	Total (µg/m^3)	Standard (µg/m^3)	% of Standard
PM_{10}	24 Hour	ISCST3	29.3	38	67	150	45
$PM_{2.5}$	24 Hour	--	(2)	--	--	35	--
	Annual	--	(2)	--	--	12	--

Table VI-4. STANDARD NO. 2 - AMBIENT AIR QUALITY STANDARDS MODELING ANALYSIS							
Pollutant	Averaging Time	Basis	Maximum Concentration (μg/m^3)$^{(1)}$	Background Concentration (μg/m^3)	Total (μg/m^3)	Standard (μg/m^3)	% of Standard
$SO_2^{(3)}$	3 Hour	ISCST3	138.1	130.9	269	1300	21
NO_2	Annual	ISCST3	20.0	19.0	39	100	39
CO	1 Hour	AERMOD	243	1450.3	1693.3	40,000	4
	8 Hour	AERMOD	120	916.0	1036.0	10,000	10
1) The highest-first-high modeled concentration was used for annual averaging periods and the highest-second-high was used for all other averaging periods, except where noted otherwise.							
2) The PM10 surrogate was used to demonstrate compliance with the PM2.5 standards.							

Table VI-5. BACKGROUND MONITORING DATA (μg/m^3)									
Pollutant	Site Name	County	Year	1-Hr	3-Hr	8-Hr	24-Hr	3-Mo	Annual
PM_{10}	Cape Romain	Charleston	2005				38		
SO_2	Cape Romain	Charleston	2005	n/a	130.9				
NO_2	Jenkens Ave Fire Sta	Charleston	2005	n/a					19.0
CO	Parklane	Richland	11-13	1450.3		916.0			
PM_{10} 24-hr is the fourth-high over three year period. The concentration listed for all other pollutants and averaging periods is the 3 year design value.									

Table VI-6. STANDARD NO. 7 - CLASS II PSD MODELING ANALYSIS					
Pollutant	Averaging Time	Basis	Maximum Concentration (μg/m^3)$^{(1)}$	Standard (μg/m^3)	% Of Standard
PM_{10}	24 Hour	ISCST3	6	30	20
	Annual	ISCST3	1	17	6
SO_2	3 Hour	ISCST3	70	512	14
	24 Hour	ISCST3	25	91	27
	Annual	ISCST3	0	20	0
NO_2	Annual	ISCST3	4	25	16
1) The highest-first-high modeled concentration was used for annual averaging periods and the highest-second-high was used for all other averaging periods.					

All sources that emit air toxics at the facility have been determined to be controlled by the HON MACT. Therefore, all toxics emissions are exempt from Standard 8.

Appendix A

Class I Area Map

Appendix B

Site Location Map

Appendix C

PSD Permit Application

Appendix D

Draft Construction Permit No. 0420-0029-CU

Appendix E

Statement of Basis

Appendix F

Public Notice of Draft PSD Construction Permit

Appendix G

Correspondence

STATEMENT OF BASIS
Page 1 of 3
BAQ Air Permitting Division

Company Name:	BP Amoco Chemical Company – Cooper River Plant	**Permit Writer:**	James C. Robinson
Permit Number:	0420-0029-CU.R1	**Date:**	**DRAFT**

EXPEDITED REVIEW: Accepted into Expedited Program December 20, 2017.
DATE APPLICATION RECEIVED: December 14, 2017
DATE OF OCRM APPROVAL: January 29, 2018

FACILITY DESCRIPTION: BP Amoco Chemical Company – Cooper River Plant (BPCR) produces only Purified Terephthalic Acid (PTA). PTA is used to make polyester fibers and films. The major raw materials in the production of PTA are Paraxylene (Px), acetic acid, caustic soda, and hydrogen. Plant operation consists mainly of: 1) utilities 2) production of crude TA, 3) purification into PTA, 4) product loading/ shipping, and 5) waste treatment along with some additional areas at the plant. There are two units that manufacture PTA: Cooper River #1 (CR#1), which consists of the #1 Oxidation (OX) Unit and the #1 PTA Unit; and Cooper River #2 (CR#2), which consists of the #2 Oxidation (OX) Unit and the #2 PTA Unit. The #1 and #2 OX Units produce crude TA and the #1 and #2 PTA Units purifies the crude TA, to make PTA.

PROJECT DESCRIPTION: The facility is proposing to change the method of operation of the #1 OX Unit. The facility has three (3) overhead condensers on its #1 Ox Unit Reactor, of which the facility currently draws a solvent/water mixture from Condensers 2 and 3. This mixture is sent to the dehydration tower (DHT), equipment ID BT-701, and the low pressure absorber (LPA), equipment ID BT-603, for ~~catalyst~~ solvent recovery. The facility is proposing to draw from all three condensers, as this provides better solvent and catalyst recovery and a more stable operation. This in turns provides a significant operational savings annually. The facility is also requesting to increase the CO BACT limit for #1 OX LPA (BT -603) from 4.1 lb/hr to 14 lb/hr, based on a 30-day rolling average.

In addition to this above-mentioned modification, the facility proposes to voluntarily decrease the CO BACT limit for the high pressure vent gas treatment system (HPVGTS) from 87.9 lb/hr to 72.0 lb/hr, based on a 30-day rolling average. This change, in effect, reduces facility wide CO emissions 6 lb/hr and 26.3 tpy.

The changes to these two CO BACT limits require revising the PSD construction permit 0420-0029-CU and the associated preliminary and final determinations. Only the portions of these three documents affected by these changes will be revised. The documents will also have general updates due to template changes.

SOURCE TEST REQUIREMENTS: In order to monitor and determine if the BACT emission limit for the #1 OX LPA is being met, the facility will be required to perform an initial source test 180 days after start-up of this modification, and once every three years thereafter.

EMISSIONS: This modification will cause an increase of carbon monoxide (CO) emissions from the LPA because the solvent/water mixture from the first condenser contains a higher concentration of CO. CO is an unwanted by-product of the reaction, and is released from the solvent/water mixture during the separation process in the DHT. CO then vents to the atmosphere through the LPA. There are no other pollutants affected by this project.

Note: Facility wide emissions of CO decrease due to the facility's proposal to voluntary reduce the CO BACT limit of the high pressure vent gas treatment system.

FACILITY WIDE EMISSIONS		
Pollutant	**Uncontrolled Emissions**	**Controlled/Limited Emissions**
	TPY	**TPY**
PM	5,394.2	77.1

FACILITY WIDE EMISSIONS		
Pollutant	**Uncontrolled Emissions**	**Controlled/Limited Emissions**
	TPY	**TPY**
PM_{10}	5,356.2	73.0
$PM_{2.5}$	5,261.6	67.9
SO_2	190.9	189.0
NOx	495.7	324.9
CO	14,820.5	1206.7
VOC	2,587.2	576.5
Lead	1.0	1.0
GHG Mass	482,000	479,586
GHG CO_2e	484,519	480,031
Highest HAP (Paraxylene)	227.9	58.5
Total HAP	1688.1	128.6

OPERATING PERMIT STATUS

BPCR is a Title V Source for PM_{10}, NOx, CO, SO_2, VOC, CO_2e, and single and combined HAPs. BPCR is a “28 Source Category” PSD major source (PTE >100 TPY) for PM, PM_{10}, NOx, CO, SO_2, VOC, and CO_2e. BPCR currently operates under an existing TV operating permit. A timely TV renewal application was submitted on February 24, 2012.

REGULATORY APPLICABILITY REVIEW	
Regulations	**Comments/Periodic Monitoring Requirements**
Section II.E – Synthetic Minor	There no synthetic minor limits being established for this project.
Standard No. 1	No fuel burning sources are being modified with this project. Project will NOT require incremental steam usage from the two existing boilers.
Standard No. 3 (state only)	This project will not change applicable requirements for this regulation.
Standard No. 4	This project will not change applicable requirements for this regulation.
Standard No. 5	This project does not contain any sources regulated under this standard.
Standard No. 5.2	No fuel burning sources are being modified with this project.
Standard No. 7	The proposed project is a change in method of operation that is subject to PSD review and will have CO emissions increases requiring a BACT analysis. The facility is proposing to increase the BACT limit of the LPA (BT-603), from 4.1 lb/hr to 14 lb/hr of CO. The (See Std 7 Table below for proposed BACT limits)
61-62.6	Fugitive PM (Dust) emissions are not associated with this project.
40 CFR 60 and 61-62.60	This project will not change applicable requirements for this regulation.
40 CFR 61 and 61-62.61	This project will not change applicable requirements for this regulation.
40 CFR 63 and 61-62.63	This project will not change applicable requirements for this regulation.
61-62.68	This project will not change applicable requirements for this regulation.
40 CFR 64 (CAM)	This project will not change applicable requirements for this regulation.

AMBIENT AIR STANDARDS REVIEW	
Regulations	**Comments/Periodic Monitoring Requirements**
Standard No. 2	Facility has demonstrated compliance through modeling for AAQS; see modeling summary dated . No operational restriction has been established to ensure compliance with the modeled emission rates.
Standard No. 7.c	This facility has demonstrated compliance through modeling for the PSD Class II increments for Berkeley County; see modeling summary dated ???.
Standard No. 8 (state only)	No modeling review was required for this standard.

Standard No. 7 Proposed BACT Limits			
Equipment	**Pollutant**	**BACT Limit**	**Control Method**
#1 OX Low Pressure Absorber	CO	14.0 lb/hr	N/A
#1 OX HPVGTS	CO	72.0	N/A

PUBLIC NOTICE

This construction permit(s) will undergo a 30-day public notice period to establish PSD LIMIT in accordance with SC Regulation 61-62.1, Section II.N and SC Regulation 61-62.5, Standard 7(q). The comment period was open from DATE to DATE and was placed on the BAQ website during that time period.

SUMMARY AND CONCLUSIONS

It has been determined that this source, if operated in accordance with the submitted application, will meet all applicable requirements and emission standards.

Re: FLM Draft Permit Review for BP Amoco PSD Revision

Robinson, James C.

Tue 5/1/2018 4:48 PM

Sent Items

To:Andrews, Marianne <Marianne.Andrews2@bp.com>;

OK on FLM. There were minor comments from the internal review. I'm looking to have drafts ready to go to public comment, awaiting FLM review.

From: Andrews, Marianne <Marianne.Andrews2@bp.com>
Sent: Thursday, April 26, 2018 1:37:57 PM
To: Robinson, James C.
Subject: RE: FLM Draft Permit Review for BP Amoco PSD Revision

James,

Catherine said she should complete her review by sometime early next week. Were there significant comments received internally? We are still trying to get a feel for when we may expect the public notice.

Thanks,
Marianne

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Wednesday, April 25, 2018 4:53 PM
To: Andrews, Marianne
Subject: Re: FLM Draft Permit Review for BP Amoco PSD Revision

No update. Will let you know when I do. You all may want to reach out to them.

From: Andrews, Marianne <Marianne.Andrews2@bp.com>
Sent: Wednesday, April 25, 2018 4:45:54 PM
To: Robinson, James C.
Cc: rvandenmeiracker@trcsolutions.com
Subject: Re: FLM Draft Permit Review for BP Amoco PSD Revision

James, any update from the FLM? I am being asked internally when we should expect the public notice. Please let me know the latest status when you get a chance.

Thanks,
Marianne

On Apr 20, 2018, at 1:32 PM, Robinson, James C. <robinsjc@dhec.sc.gov> wrote:

> You're welcome. Will do.

From: Andrews, Marianne <Marianne.Andrews2@bp.com>
Sent: Friday, April 20, 2018 1:07:05 PM
To: Robinson, James C.; rvandenmeiracker@trcsolutions.com
Subject: RE: FLM Draft Permit Review for BP Amoco PSD Revision

Thanks for the update. Please let us know when you hear back from her.

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Friday, April 20, 2018 9:21 AM
To: rvandenmeiracker@trcsolutions.com; Andrews, Marianne
Subject: FLM Draft Permit Review for BP Amoco PSD Revision

Just a heads up that the FLM requested additional time to review the draft documents. She hasn't stated how much more time she needs yet.

James C. Robinson, P.E.
Environmental Engineer
Air Permitting Division
Bureau of Air Quality
Office: (803) 898-0660
Connect: www.scdhec.gov Facebook Twitter

dhec
Healthy People. Healthy Communities.

Re: [EXTERNAL] BP Cooper River

Robinson, James C.

Wed 5/9/2018 4:32 PM

Sent Items

To:rvandenmeiracker@trcsolutions.com <rvandenmeiracker@trcsolutions.com>;

Cc:McAvoy, Bryan P. <mcavoybp@dhec.sc.gov>; Glass, John <glassjp@dhec.sc.gov>;

OK, thanks.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Wednesday, May 9, 2018 4:30:59 PM
To: Robinson, James C.
Subject: RE: [EXTERNAL] BP Cooper River

She asked me for the changes verbally.

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Wednesday, May 9, 2018 4:26 PM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>; McAvoy, Bryan P. <mcavoybp@dhec.sc.gov>
Cc: John Glass <glassjp@dhec.sc.gov>
Subject: Re: [EXTERNAL] BP Cooper River

Rob, I don't see Catherine's original response to the original results.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Wednesday, May 9, 2018 4:23:13 PM
To: McAvoy, Bryan P.
Cc: Robinson, James C.; Glass, John
Subject: FW: [EXTERNAL] BP Cooper River

FYI, please see the following correspondence. Awaiting response from Catherine.

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: VandenMeiracker, Robert
Sent: Tuesday, May 8, 2018 3:44 PM
To: Collins, Catherine <catherine_collins@fws.gov>
Subject: RE: [EXTERNAL] BP Cooper River

OK. Try this version.

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

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O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Collins, Catherine [mailto:catherine_collins@fws.gov]
Sent: Tuesday, May 8, 2018 3:32 PM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Subject: Re: [EXTERNAL] BP Cooper River

The BPCOOP.SUM file would not open because it may be damaged. Could you please resend. Thanks

Catherine Collins, Environmental Engineer
U.S. Fish and Wildlife Service
Branch of Air and Water Quality Resources
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235-2034
303-914-3807
(303) 969-5444 fax
Catherine_Collins@fws.gov

On Tue, May 8, 2018 at 1:08 PM, VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com> wrote:

> Catherine,
>
> We reran the model based on your request for a different background value. The results are attached.
>
> 1. The visibility test passes for the Class 1 area. See the attached summary document. Note that Class I visibility thresholds are exceeded outside of the Class I area, but this is not an area subject to Class I visibility values.
>
> 2. With respect to stability class and wind speed, these are model selected that are worst-case. This is not an input that we select.
>
> Please let me know if you have any other questions.
>
> Thanks,
>
> Rob
>
> Robert vandenMeiracker
> Office Practice Leader – Air Quality Consulting
>
> **We moved! Please note our new address:**
>
> 50 International Drive, Suite 150, Greenville, SC 29615
> O: 864.787.5261 | F: 864.281.0288
> rvandenmeiracker@trcsolutions.com
> LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

Fwd: [EXTERNAL] Expedited Draft Permit Review for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Andrews, Marianne <Marianne.Andrews2@bp.com>

Thu 5/17/2018 6:49 PM

To:Robinson, James C. <robinsjc@dhec.sc.gov>;

1 attachments (2 KB)

image001.jpg;

Hi, James,

Please see below. I did not see your name on Catherine's email.

Please let me know when we may expect the public notice to be published.

Thanks,
Marianne

Sent from my iPhone

Begin forwarded message:

> **From:** "Collins, Catherine" <catherine_collins@fws.gov>
> **Date:** May 17, 2018 at 6:33:02 PM EDT
> **To:** "Andrews, Marianne" <Marianne.Andrews2@bp.com>
> **Cc:** "VandenMeiracker, Robert (RVandenMeiracker@trcsolutions.com)" <RVandenMeiracker@trcsolutions.com>
> **Subject:** Re: [EXTERNAL] Expedited Draft Permit Review for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1
>
> Thank you for providing the additional information and VISCREEN Level-1 Analysis for the BP Amoco Chemical Company - Cooper River Plant, Wando, South Carolina project. The proposed project is a modification to the Prevention of Significant Deterioration permit to debottleneck the #1 and #2 Oxidation Units and make modifications to the Purified Terephthalic Acid Unit. Additionally, other minimal ancillary process with be optimized.
>
> The Fish and Wildlife Service has reviewed the additional Air Quality Related Value (AQRV) analysis information provided. The Service has determined that information provided is sufficient and that the VISCREEN analysis shows that the AQRV impact at Class I area is not above the threshold levels. Thank you for the opportunity to review this project.
>
> Should you need further information or have questions, please feel free to call.
>
> Catherine Collins, Environmental Engineer
> U.S. Fish and Wildlife Service
> Branch of Air and Water Quality Resources
> 7333 W. Jefferson Ave., Suite 375
> Lakewood, CO 80235-2034
> 303-914-3807
> (303) 969-5444 fax
> Catherine_Collins@fws.gov
>
> On Tue, May 15, 2018 at 11:40 AM, Andrews, Marianne <Marianne.Andrews2@bp.com> wrote:
>
>> Hi, Catherine,
>>
>> Any update on when we can expect your approval? This project is business critical, and we would like to address any concerns you may have as soon as possible, so we can progress the permitting process.
>>
>> Thanks,
>>
>> Marianne
>>
>> ---
>>
>> **From:** Andrews, Marianne
>> **Sent:** Friday, May 04, 2018 10:57 AM
>> **To:** 'catherine_collins@fws.gov'
>> **Cc:** VandenMeiracker, Robert (RVandenMeiracker@trcsolutions.com)
>> **Subject:** FW: [EXTERNAL] Expedited Draft Permit Review for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1
>>
>> Catherine,

Have you had a chance to review our modeling results sent to you on Wednesday? James is waiting on your approval to proceed with the permit. Please let us know if you have any questions. Otherwise, please let James know that you have reviewed and approved the modeling.

Thanks for your help,

Marianne

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Friday, May 04, 2018 10:50 AM
To: Andrews, Marianne
Cc: rvandenmeiracker@trcsolutions.com
Subject: Re: [EXTERNAL] Expedited Draft Permit Review for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Marianne, we do except for FLM's approval of the modeling that Rob sent.

From: Andrews, Marianne <Marianne.Andrews2@bp.com>
Sent: Friday, May 4, 2018 10:16:14 AM
To: Robinson, James C.
Cc: rvandenmeiracker@trcsolutions.com
Subject: FW: [EXTERNAL] Expedited Draft Permit Review for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

James,

Do you now have everything you need to finalize the draft and prepare the public notice?

Thanks,

Marianne

From: VandenMeiracker, Robert [mailto:RVandenMeiracker@trcsolutions.com]
Sent: Wednesday, May 02, 2018 6:00 PM
To: Collins, Catherine
Cc: Andrews, Marianne; Robinson, James C.
Subject: RE: [EXTERNAL] Expedited Draft Permit Review for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Catherine,

As requested, please see the attached VISCREEN modeling files. The model results indicate that "Screening Criteria ARE NOT Exceeded". Thus, there is not a predicted impact on the visibility of the Class I area.

Please let us know if you have any further questions.

Thanks,

Rob

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

cid:image001.jpg@01D046E5.1EE7D7B0
50 International Drive, Suite 150, Greenville, SC 29615

O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com

LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Collins, Catherine [mailto:catherine_collins@fws.gov]
Sent: Wednesday, May 2, 2018 3:37 PM
To: Robinson, James C. <robinsjc@dhec.sc.gov>
Cc: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Subject: Re: [EXTERNAL] Expedited Draft Permit Review for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Hi James,

Thank you for sending the information regarding the BP Amoco Chemical Company - Cooper River Plant, Wando, South Carolina project. The proposed project is a modification to the Prevention of Significant Deterioration permit to debottleneck the #1 and #2 Oxidation Units and make modifications to the Purified Terephthalic Acid Unit. Additionally, other minimal ancillary process with be optimized. These modifications will result in Carbon Monoxide and Volatile Organic Compound emissions have triggered a PSD modification. Additionally there will be emissions increases for PM-10, PM 2.5, NOx and SOx.

The Fish and Wildlife Service has reviewed the information provided in the permit application, draft permit containing Air Quality Related Values analysis, the identified emission changes, and distance from the Class I area(s) as listed below. The Service has determined that information provided is sufficient and would like to request that the VISCREEN model be run for the pollutants listed below. While the PSD action was triggered for CO and VOC, in these cases once PSD is triggered we look at the emissions increases for all pollutants in determining impact to the Class I area. Should you need further information on the modeling or have questions, please feel free to call. Please provide the modeling results once completed and discuss the results in the permit and technical documentation.

Please note that we are specifically addressing the need for an AQRV analysis for Class I areas managed by the Fish and Wildlife Service. Additionally, should the emissions or the nature of the project change significantly, please contact me, so that we might reevaluate the revised proposed project.

Class I Area:

Cape Romain NWR

Distance to Facility in kilometers

24 km

Annual Emissions (based on short term maximum emission rates adjusted to an annual emission rate) in tons per year (tpy)

+ 27.8	Nitrogen Oxides
+ 0.2	Sulfur Oxides
+ 6.6	Total Fine particulate matter
34.60	Total TPY

The state and/or EPA may have a different opinion regarding the need for a Class I increment analysis.

Thank you for keeping us informed and involving the Fish and Wildlife Service in this project and thank you for the additional review time.

Catherine Collins

Catherine Collins, Environmental Engineer

U.S. Fish and Wildlife Service

Branch of Air and Water Quality Resources

7333 W. Jefferson Ave., Suite 375

Lakewood, CO 80235-2034

303-914-3807

(303) 969-5444 fax

Catherine_Collins@fws.gov

On Fri, Apr 20, 2018 at 5:33 AM, Robinson, James C. <robinsjc@dhec.sc.gov> wrote:

> Sure Catherine. How much time do you think you need?
>
> ---
>
> **From:** Collins, Catherine <catherine_collins@fws.gov>
> **Sent:** Thursday, April 19, 2018 10:56:12 PM
> **To:** Robinson, James C.
> **Subject:** Re: [EXTERNAL] Expedited Draft Permit Review for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1
>
> James,
>
> Could I please ask for more time to review this permit. There have been many issues at our office this week.
>
> Thank you!
>
> Catherine
>
> Catherine Collins, Environmental Engineer
>
> U.S. Fish and Wildlife Service
>
> Branch of Air and Water Quality Resources
>
> 7333 W. Jefferson Ave., Suite 375
>
> Lakewood, CO 80235-2034
>
> 303-914-3807
>
> (303) 969-5444 fax
>
> Catherine_Collins@fws.gov
>
> On Thu, Apr 12, 2018 at 12:48 PM, Robinson, James C. <robinsjc@dhec.sc.gov> wrote:
>
>> Please review the following draft documents and provide comments by COB, Thursday, April 19. Note that the documents are in track changes. I am also having a formatting issue with the preliminary determination; however, I will be working on it while the drafts are being reviewed.
>>
>> **James C. Robinson, P.E.**
>>
>> Environmental Engineer
>>
>> Air Permitting Division
>>
>> **Bureau of Air Quality**
>>
>> Office: (803) 898-0660
>> Connect: www.scdhec.gov Facebook Twitter

Re: 2nd Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Robinson, James C.

Mon 5/21/2018 3:23 PM

Sent Items

To:rvandenmeiracker@trcsolutions.com <rvandenmeiracker@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>;

OK. Thanks.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Monday, May 21, 2018 3:18:25 PM
To: Robinson, James C.; Andrews, Marianne
Subject: RE: 2nd Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

OK, got it. That language is similar to what we agreed upon previously, so that is fine.

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Monday, May 21, 2018 2:52 PM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>
Subject: Re: 2nd Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Scroll down to the bottom of the project description.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Monday, May 21, 2018 2:32:20 PM
To: Robinson, James C.; Andrews, Marianne
Subject: RE: 2nd Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Ok, that's what I thought. I did not see any difference between the two most recent versions. Is there a specific paragraph(s) that were changed?

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Monday, May 21, 2018 2:25 PM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>
Subject: Re: 2nd Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

I'm referring to the Project Description.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Monday, May 21, 2018 12:27:48 PM
To: Robinson, James C.; Andrews, Marianne
Subject: RE: 2nd Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

James,

To which section and document are you referring?

The Permit Section related to description of changes?

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Monday, May 21, 2018 12:11 PM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>
Subject: Re: 2nd Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Rob, I also updated the permit description to include language of the changes. Note that any changes requested during the public comment period will delay the issuance of the permit even more, as we will have to officially respond to the comments and include them in the PD.

If there are not major comments from management, I think it will go out for public notice this week. I will keep you all posted.

From: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>
Sent: Monday, May 21, 2018 11:05:29 AM
To: Robinson, James C.; Andrews, Marianne
Subject: RE: 2nd Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

James,

This looks good to us. As far as we can tell, the only changes between this and the previous versions are related to formatting and the addition of visibility modeling requested by FLM. Do I have that correct?

If yes, then please proceed with sending this on for public notice. Is it reasonable to assume that this will be posted on the DHEC website by the end of the week?

Thanks,

Rob

Robert vandenMeiracker
Office Practice Leader – Air Quality Consulting

We moved! Please note our new address:

50 International Drive, Suite 150, Greenville, SC 29615
O: 864.787.5261 | F: 864.281.0288
rvandenmeiracker@trcsolutions.com
LinkedIn | Twitter | Blog | Flickr | www.trcsolutions.com

From: Robinson, James C. [mailto:robinsjc@dhec.sc.gov]
Sent: Monday, May 21, 2018 9:01 AM
To: VandenMeiracker, Robert <RVandenMeiracker@trcsolutions.com>; Andrews, Marianne <Marianne.Andrews2@bp.com>
Subject: 2nd Draft Permit for BP Amoco Cooper River PSD Revision 0420-0029-CU.R1

Enclosed is an updated draft of the PSD revision documents. Take one more quick look before I send it on to final approval for public notice.

James C. Robinson, P.E.
Environmental Engineer
Air Permitting Division
Bureau of Air Quality
Office: (803) 898-0660
Connect: www.scdhec.gov Facebook Twitter