

TABLE OF EXHIBITS - Docket ID No. EPA-R09-OAR-2013-0588
Comments on Proposed Phase 3 Arizona Regional Haze FIP

Exhibit 1	National Park Service, <i>Grand Canyon General Management Plan</i> (1995) (Excerpts)
Exhibit 2	National Park Service, Grand Canyon, Plan Your Park Visit
Exhibit 3	Catherine C. Thomas et al., NPS, <i>2012 National Park Visitor Spending Effects</i> (2014)
Exhibit 4	EPA, Health – Nitrogen Dioxide, Sulfur Dioxide, Particulate Matter
Exhibit 5	Dr. George D. Thurston, <i>Written Report Regarding the Proposed Navajo Generating Plant EPA Rulemaking</i> (Dec. 12, 2013)
Exhibit 6	EPA, Fact Sheet - Final Amendments to the RHR and BART Guidelines
Exhibit 7	Ceres, <i>New Jobs – Cleaner Air: Employment Effects Under Planned Changes to the EPA’s Air Pollution Rules</i> (2011)
Exhibit 8	Daniel J. Stynes, Mich. State Univ., <i>Economic Benefits to Local Communities from National Park Visitation and Payroll, 2010</i> (2011)
Exhibit 9	Jared Hardner & Bruce McKenney, Hardner & Gullison, <i>The U.S. National Park System, An Economic Asset at Risk</i> (2006)
Exhibit 10	Abt Associates Inc., <i>Out of Sight: The Science and Economics of Visibility Impairment</i> (2000)
Exhibit 11	EPA, Effects of Acid Rain and Ground-level Ozone
Exhibit 12	William D. Bowman et al., <i>Nitrogen critical loads for alpine vegetation and soils in Rocky Mountain National Park</i> , 103 J. Env’tl. Mgmt. 165 (2012)
Exhibit 13	National Park Service, Nitrogen Deposition: Issues and Effects in Rocky Mountain National Park (2005)
Exhibit 14	Nathanael Massey, <i>As Colo. firefighters gain upper hand, scientist says pollution fueled forest vulnerability</i> , ClimateWire, July 2, 2012
Exhibit 15	Corrected Final Brief of Respondent EPA, <i>Am. Corn Growers Ass’n v. EPA</i> , 291 F.3d 1 (D.C. Cir. 2002) (No. 99-1348)
Exhibit 16	Consent Decree and Deadline Extensions in <i>Nat’l Parks Conservation Ass’n v. Jackson</i> , No. 11-cv-01548-ABJ (D.D.C.)
Exhibit 17	Nat’l Parks Conservation Ass’n, <i>On an Approach for Improving Visibility in Class I Areas Using Visibility Restoration Plans (VRPs) with an Example VRP for the Grand Canyon National Park</i> (2014)
Exhibit 18	EPA, <i>Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns</i> (2007)
Exhibit 19	NESCAUM, <i>Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness</i> (2000)
Exhibit 20	Richard Bolwerk et al., <i>German Contribution to the Review of the Reference Document on Best Available Techniques in the Cement and Lime Manufacturing Industries, Part II: Cement Manufacturing Industries</i> (2006)

Exhibit 21	ERG, Inc., <i>Assessment of NO_x Emissions Reduction Strategies for Cement Kilns – Ellis County</i> (2006)
Exhibit 22	Tim Vanderpool, <i>Polluting the Poor</i> , Tucson Weekly, Dec. 13, 2012
Exhibit 23	NAACP et al., <i>Coal Blooded, Putting Profits Before People</i> (2012)
Exhibit 24	Victoria Stamper Expert Report on Phase 1 Rule
Exhibit 25	Dr. Ranajit Sahu Expert Report on Phase 1 Rule
Exhibit 26	Letter from Eric L. Hiser, Jorden Bischoff & Hiser, P.L.C., to Robert Perciasepe & Jared Blumenfeld, EPA (May 29, 2013)
Exhibit 27	Letter from David C. Foerter, Inst. of Clean Air Cos., to Senator Thomas Carper (Nov. 3, 2010)
Exhibit 28	EPA, <i>An Assessment of the Feasibility of Retrofits for the Mercury and Air Toxics Standards Rule</i> (2011)
Exhibit 29	EPA, AP-42, <i>Compilation of Air Pollutant Emission Factors</i> , at 12.3-19, 12.3-20 (1995) (Excerpts)
Exhibit 30	C.J. Newman et al., <i>Recent operation and environmental control in the Kennecott Smelter</i>
Exhibit 31	Valérie Léveillé & Colin Ryan, Cansolv, <i>Reducing Sulfuric Acid Plant SO₂ Emissions with the CANSOLV SO₂ Scrubbing System</i> (2009)
Exhibit 32	Paykan Safe & Robert L. Stephens, <i>Peirce-Smith Converter Hood Design Analysis Using Computational Fluid Dynamic Modeling</i> (2000)
Exhibit 33	Cost-Effectiveness Discussion
Exhibit 34	Consent Decree, <i>United States v. Cemex, Inc.</i> , No. 09-cv-00019-MSK-MEH (D. Colo. Apr. 19, 2013)
Exhibit 35	EPA, <i>Technical Bulletin: Nitrogen Oxides (NO_x), Why and How They Are Controlled</i> (1999)

EXHIBIT 19

Status Report on NO_x Controls

for

Gas Turbines

Cement Kilns

Industrial Boilers

Internal Combustion Engines

Technologies & Cost Effectiveness

December 2000



Members of Northeast States for Coordinated Air Use Management

Carmine DiBattista, Bureau Chief
Connecticut Department of Environmental Protection, Bureau of Air Management

James P. Brooks, Bureau Director
Maine Department of Environmental Protection, Bureau of Air Quality

Nancy L. Seidman, Deputy Director of Air Programs
Massachusetts Department of Environmental Protection, Bureau of Waste Prevention

Kenneth A. Colburn, Director
New Hampshire Department of Environmental Services, Air Resources Division

John C. Elston, Administrator
New Jersey Department of Environmental Protection, Office of Air Quality Management

Robert R. Warland, Director
New York Department of Environmental Conservation, Division of Air Resources

Stephen Majkut, Chief
Rhode Island Department of Environmental Management, Office of Air Resources

Richard A. Valentinetti, Director
Vermont Department of Environmental Conservation, Air Pollution Control Division

Jason Grumet, Executive Director
Northeast States for Coordinated Air Use Management

Status Report on NO_x Controls
for
Gas Turbines
Cement Kilns
Industrial Boilers
Internal Combustion Engines
Technologies & Cost Effectiveness

December 2000

Project Director

Praveen K. Amar, Ph.D., P.E.
Director, Science and Policy, NESCAUM

Prepared by:

James Staudt, Ph.D.
Andover Technology Partners
North Andover, MA 01845
www.andovertechnology.com

NESCAUM

Northeast States for Coordinated Air Use Management
129 Portland Street, Boston, MA 02114

www.nescaum.org

Status Report on NO_x for Industrial Boilers, Gas Turbines, Internal Combustion Engines and Cement Kilns; Control Technologies and Cost Effectiveness

Project Director

Praveen Amar, NESCAUM

Principal Investigator

James Staudt, Andover Technology Partners

Technical Editor

Ingrid Ulbrich, NESCAUM

Administrative Support

Karen Fadely, Lisa Fishbone, NESCAUM

Acknowledgements

Preparation of this report was funded by the Office of Atmospheric Programs and the Office of Air Quality Planning and Standards of the United States Environmental Protection Agency.

The effort was managed by the Northeast States for Coordinated Air Use Management (NESCAUM). Andover Technology Partners was the prime contractor to NESCAUM.

A unique feature of this report is a collection of case studies (Chapter IV) of real-world experience with NO_x control technologies. The case studies outline recent industrial sector (non-electricity generating sector) experience with control technologies in the United States. This chapter was prepared in cooperation with operators of industrial facilities that are utilizing a number of NO_x control technologies for industrial boilers, gas turbines, internal combustion engines, and cement kilns. These companies undertook a substantial level of effort in providing the operating and cost information on control technologies that was the basis for the preliminary version of case studies, prepared by Andover Technology Partners. The preliminary case studies were then reviewed and approved by the industrial operators before inclusion of final versions in this report. Without their assistance, this important aspect of the report would not have been possible.

This report was reviewed by the members of Stationary Source and Permits Committee of NESCAUM, key technical staff from other states in the Ozone Transport Region, and staff from the U.S. Environmental Protection Agency.

Table of Contents

Acknowledgements

I. Executive Summary.....	I-1
A. Report Objectives and Organization	I-1
B. NOx Control Technologies and Cost Effectiveness.....	I-2
B.1 Industrial Boilers	I-2
B.2 Gas Turbines	I-4
B.3 Internal Combustion Engines	I-5
B.4 Cement Kilns.....	I-6
C. Case Studies	I-7
II. NOx Control Technologies.....	II-1
A. Industrial Boilers	II-1
A.1 Primary Methods of Controlling NOx in Industrial Boilers	II-2
A.2 Secondary Methods of Controlling NOx in Industrial Boilers	II-4
B. Gas Turbines	II-12
B.1 Primary Methods of Controlling NOx from Gas Turbines	II-12
B.2 Secondary Methods of Controlling NOx from Gas Turbines	II-17
C. Internal Combustion (IC) Engines	II-21
C.1 Primary Methods of Controlling NOx from IC Engines.....	II-21
C.2 Secondary Methods of Controlling NOx from IC Engines.....	II-22
D. Cement Kilns.....	II-25
D.1 Primary Methods of Controlling NOx from Cement Kilns.....	II-28
D.2 Secondary Methods of Controlling NOx from Cement Kilns.....	II-34
D.3 Combination of Technologies	II-37
E. Summary	II-37
F. References	II-38
III. Technology Costs	III-1
A. Costs of Control	III-1
A.1 Cost Data	III-1
B. General Methodology.....	III-2
B.1 Components of Cost.....	III-3
B.2 Cost Analysis.....	III-5
C. Industrial Boilers	III-7
C.1 Cost Effectiveness of Primary Methods of Controlling NOx from Industrial Boilers.....	III-7
C.2 Cost Effectiveness of Secondary Methods of Controlling NOx from Industrial Boilers	III-10
D. Gas Turbines	III-15
D.1 Cost Effectiveness of Primary Methods of Controlling NOx from Gas Turbines.....	III-15
D.2 Cost Effectiveness of Secondary Methods of Controlling NOx from Gas Turbines.....	III-21

E.	Internal Combustion (IC) Engines	III-26
E.1	Cost Effectiveness of Primary Methods of Controlling NO _x from IC Engines.....	III-26
E.2	Cost Effectiveness of Secondary Methods of Controlling NO _x from IC Engines.....	III-30
F.	Cement Kilns.....	III-32
F.1	Cost Effectiveness of Primary Methods of Controlling NO _x from Cement Kilns	III-33
F.2	Cost Effectiveness of Secondary Methods of Controlling NO _x from Cement Kilns	III-37
G.	Summary	III-39
H.	References	III-40
IV.	Case Studies	IV-1
A.	Introduction	IV-1
B.	Industrial Boiler Case Studies	IV-2
B.1	Case Study BLR-1, Minergy Corp, Neenah, Wisconsin.....	IV-2
B.2	Case Study BLR-2, International Paper, Jay, Maine.....	IV-3
B.3	Case Study BLR-3, Chevron Process Heater Equipped with SCR, El Segundo, California.....	IV-4
B.4	Case Study BLR-4, Sauder Woodworking, Archbold, Ohio	IV-6
B.5	Case Study BLR-5, Michigan State University, TB Simon Power Plant, Unit #4, East Lansing, Michigan.....	IV-8
B.6	Case Study BLR-6, Temple Inland Corp. Shipperville, Pennsylvania.....	IV-10
B.7	Case Study BLR-7, Fort James Corporation, Green Bay, Wisconsin.....	IV-12
B.8	Case Study BLR-8: Eastman Kodak Boiler #15, Micronized Coal Reburn, Rochester, New York.....	IV-13
B.9	Case Study BLR-9: Eastman Kodak Boilers #41, 42, 43. Gas Reburn, Rochester, New York.....	IV-15
C.	Gas Turbine Case Studies	IV-19
C.1	Case Study GT-1, Duke Energy, Cromwell, Connecticut.....	IV-19
C.2	Case Study GT-2, Duke Energy, Southeast, New York.....	IV-23
C.3	Case Study GT-3, Duke Energy, Stony Point, New York	IV-27
C.4	Case Study GT-4 Kern River and Sycamore Cogeneration Projects, Bakersfield, California.....	IV-31
C.5	Case Study GT-5 PG&E Generating, Manchester Street Station, Providence, Rhode Island.....	IV-33
C.6	Case Study GT-6 PG&E Generating, Pittsfield Generating Plant, Pittsfield, Massachusetts.....	IV-34
C.7	Case Study GT-7, Tennessee Gas Pipeline, Lockport, New York.....	IV-36
D.	Internal Combustion Engine Case Studies	IV-39
D.1	Case Study IC-1, SYCOM Enterprises, Linden, New Jersey	IV-39
D.2	Case Study IC-2, Duke Energy, Stony Point, New York.....	IV-40
D.3	Case Study IC-3, Duke Energy, Burrillville, Rhode Island	IV-42
D.4	Case Study IC-4, Duke Energy, Cromwell, Connecticut.....	IV-45
D.5	Case Study IC-5, NORESKO, Plymouth Cogeneration, Plymouth, New Hampshire ...	IV-48
D.6	Case Study IC-6, Tennessee Gas Pipeline, Mercer, Pennsylvania.....	IV-49
D.7	Case Study IC-7, Tennessee Gas Pipeline, Syracuse, New York	IV-52

D.8 Case Study IC-8, Tennessee Gas Pipeline, Coudersport, Pennsylvania	IV-54
E. Cement Kiln Case Studies.....	IV-56
E.1 Case Study CK-1, California Portland Cement, Colton, California.....	IV-56
E.2 Case Study CK-2, Texas Industries, Inc., Midlothian, Texas	IV-57
E.3 Case Study CK-3, Blue Circle Cement, Atlanta, Georgia	IV-59
E.4 Case Study CK-4, Ash Grove Cement, Foreman, Arkansas.....	IV-60
Appendixes: Worksheets for Economic Analysis	IV-1
Boiler Worksheets	IV-2
Gas Turbine Worksheets	IV-18
Reciprocating Internal Combustion Engine Worksheets	IV-34
Cement Kiln Worksheets	IV-46

List of Figures

Figure II-1: SNCR Applied to a Boiler	II-6
Figure II-2: Selective Catalytic Reduction	II-9
Figure II-3: Conventional Gas Reburning.....	II-10
Figure II-4: Fuel-Lean Gas Reburning.....	II-11
Figure II-5: Electro-Catalytic Oxidation Technology.....	II-12
Figure II-6: Comparison of a Lean Premixed Combustor and a Conventional Combustor	II-13
Figure II-7: Solar Turbines' SoLoNOx TM DLN and Standard Combustor with Conventional Combustion Technology	II-16
Figure II-8: Schematic of a Catalytic Gas Turbine Combustor	II-17
Figure II-9: SCR Installation on Combined Cycle Gas Turbine	II-18
Figure II-10: Low-Temperature SCR Installed on a Combined Cycle Gas Turbine	II-19
Figure II-11: A Diagram of SCONOx TM and SCOSOx TM	II-20
Figure II-12: Pre Chamber Low Emission Combustion Retrofit	II-23
Figure II-13: Urea SCR System (ARIS TM 2000) for IC Engines	II-25
Figure II-14: Simplified Sketch of a Rotary Kiln.....	II-26
Figure II-15: A Precalciner Cement Kiln with Five-Stage Cyclonic Preheater/Precalciner	II-27
Figure II-16: NOx Emissions for Various Cement Kiln Types	II-28
Figure II-17a: Frequency of NOx Values on Cement Kiln with Mid-Kiln Tire Injection (Without Mixing Air)	II-30
Figure II-17b Frequency of NOx Values for the Cement Kiln with Mid-Kiln Tire Injection in Figure II-17a (With Mixing Air)	II-31
Figure II-18: A Preheater Kiln Adding Steel Slag For CemStar	II-32
Figure II-19a: Base Case Testing (without CemStar) - NOx versus Burn-Zone Temperature ⁴⁵ ...	II-33
Figure II-19b: CemStar Testing - NOx versus Burn Zone Temperature	II-33
Figure II-20a: NOx Emissions at Ash Grove Cement After Process Control (from Case Study CK-4)	II-35
Figure II-20b: NOx Emissions Histogram at Ash Grove Cement Before Process Control (from Case Study CK-4)	II-35
Figure II-21: Biosolids Injection Process Equipment on a Precalciner Kiln	II-37
Figure III-1: Cost Effectiveness (\$/ton of NOx reduced) of Reducing NOx from a 75 MW Turbine by DLN Retrofit of Turbine Originally Equipped with Water Injection	III-19
Figure III-2: Capital Cost of Gas Turbine Exhaust Treatment NOx Reduction Technologies (Refs. 9 and 14)	III-22
Figure III-3: Cubic Meters of SCR Catalyst for Turbine with HRSG (Ref. 16).....	III-23
Figure IV-1: Nitrogen Oxide Emission Burning Tires vs. Not-Burning Tires	IV-63
Figure IV-2: Effect of Tires and Process Control on NOx Emissions	IV-64

List of Tables

Table II-1: Industrial Boiler Firing Configurations and Typical Primary Fuels	II-1
Table II-2: Statistics Regarding Low-NO _x Air Register Burner Performance for Boilers Over ~250 MMBTU/hr	II-4
Table II-3a: Performance of Industrial Boiler Types Equipped with Urea SNCR	II-7
Table II-3b: Performance of Industrial Boiler Types Equipped with Ammonia SNCR	II-7
Table II-4a: NO _x Performance of Solar Industrial Gas Turbines with SoLoNO _x TM Dry Low NO _x Combustor	II-14
Table II-4b: NO _x Performance of Large Gas Turbines with Dry Low NO _x	II-15
Table II-5: Summary of Cement Kiln Process Types in U.S.	II-26
Table II-6: NO _x Reduction at Cement Kilns Using Mid-Kiln Technology	II-30
Table II-7: NO _x Reduction Performance of Urea SNCR on Precalciner Cement Kilns	II-36
Table III-1: Assumptions for Pro Forma Economic Analysis.....	III-4
Table III-3a: Cost Effectiveness for NO _x Reduction with LNB on a 350 MMBTU/hr Coal-Fired Boiler with Capital Cost of \$5,000/MMBTU/hr (36% NO _x Reduction From 0.60 lb/MMBTU).....	III-8
Table III-3b: Cost Effectiveness for NO _x Reduction with LNB on a 350 MMBTU/hr Coal-Fired Boiler with Capital Cost of \$5,000/MMBTU/hr (25% NO _x Reduction From 0.60 lb/MMBTU).....	III-8
Table III-4a: Cost Effectiveness for NO _x Reduction with LNB on One Gas-Fired 350 MMBTU/hr Boiler	III-9
Table III-4b: Cost Effectiveness for NO _x Reduction Through Minor Modifications on One 350 MMBTU/hr Boiler	III-9
Table III-5: Cost Effectiveness for Burner Modification on Two Oil-Fired 680 MMBTU/hr Boilers	III-9
Table III-6: Reported Cost of Urea SNCR for Wood-Fired Power Boilers	III-10
Table III-7: Cost Effectiveness for SNCR NO _x Reduction on a 350 MMBTU/hr Boiler.....	III-11
Table III-8a: Cost Effectiveness for SCR NO _x Reduction on a 350 MMBTU/hr Coal-Fired Boiler - 80% NO _x Reduction from 0.45 lb/MMBTU and Capital Cost of \$10,000/MMBTU/hr.....	III-12
Table III-8b: Cost Effectiveness for SCR NO _x Reduction on a 350 MMBTU/hr Coal-Fired Boiler - 80% NO _x Reduction from 0.45 lb/MMBTU and Capital Cost of \$15,000/MMBTU/hr.....	III-12
Table III-9a: Cost Effectiveness for SCR NO _x Reduction on a 350 MMBTU/hr Gas-Fired Boiler	III-13
Table III-10a: Cost Effectiveness of NO _x Reduction by Conventional Gas Reburn, Assuming 55% NO _x Reduction from 0.45 lb/MMBTU, 20% Gas Injection, and \$0.75/MMBTU Incremental Fuel Cost for Gas.....	III-14
Table III-10b: Same as 3.10a, Except \$1.00/MMBTU Incremental Fuel Cost for Gas.....	III-14
Table III-11a: Cost Effectiveness of NO _x Reduction by FLGR, Assuming 35% NO _x Reduction from 0.45 lb/MMBTU, 6% Gas Injection, and \$0.75/MMBTU Incremental Fuel Cost for Gas.....	III-14
Table III-11b: Same as 3.11a, Except \$1.00/MMBTU Incremental Fuel Cost for Gas.....	III-14
Table III-12a: Cost Effectiveness of NO _x Reduction by AEFLGR, Assuming 60% NO _x Reduction from 0.45 lb/MMBTU, 6% Gas Injection, NSR=1.2 and \$0.75/MMBTU Incremental Fuel Cost for Gas	III-15
Table III-12b: Same as III-12a, Except \$1.00/MMBTU Incremental Fuel Cost for Gas.	III-15

Table III-13. Cost Effectiveness (\$/ton) for Two Solar Centaur (7000 hp each) Retrofit with DLN for Reducing NOx from 135 to 50 ppm (63% reduction).....	III-17
Table III-14. Cost Effectiveness (\$/ton) for Retrofit of Two Solar Mars (2x13,000 hp).....	III-17
Table III-15. Cost Effectiveness for 75 MW GE Turbine Retrofit with DLN from Conventional Combustion, Reduction from 154 ppm to 15 ppm (90% reduction).....	III-18
Table III-16. Cost Effectiveness for 75 MW Turbine Retrofit with DLN from Water Injection, Reduction from 42 ppm to 15 ppm	III-18
Table III-17a: Estimated Cost Effectiveness for Diluent Injection on Twenty-Four 21-MW Peaking Turbines. Reduction from 125 ppm to 50 ppm (gas firing)	III-20
Table III-17b: Estimated Cost Effectiveness for Diluent Injection on Twenty-Four 21-MW Peaking Turbines. Reduction from 180 ppm to 50 ppm (distillate oil firing).....	III-21
Table III-18a: Cost Effectiveness for SCR Retrofit on Simple Cycle 75 MW Gas Turbine with Baseline NOx of 154 ppm and Controlled to 15 ppm (90% Control).....	III-24
Table III-18b: Cost Effectiveness for SCR Retrofit on Simple Cycle 75 MW Gas Turbine with Baseline NOx of 42 ppm and Controlled to 7 ppm (83% Control).....	III-24
Table III-18c: Cost Effectiveness for SCR Retrofit on Simple Cycle 75 MW Gas Turbine with Baseline NOx of 15 ppm and Controlled to 3 ppm (80% Control).....	III-24
Table III-18d: Cost Effectiveness for SCR retrofit on Simple Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 142 ppm and Controlled to 15 ppm (89% Control)	III-24
Table III-18e: Cost Effectiveness for SCR retrofit on Simple Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 42 ppm and Controlled to 5 ppm (88% Control)	III-24
Table III-19a: Cost Effectiveness for Conventional SCR on Combined Cycle 75 MW Gas Turbine with Baseline NOx of 154 ppm and Controlled to 15 ppm.....	III-25
Table III-19b: Cost Effectiveness for Conventional SCR on Combined Cycle 75 MW Gas Turbine with Baseline NOx of 42 ppm and Controlled to 7 ppm.....	III-26
Table III-19c: Cost Effectiveness for Conventional SCR on Combined Cycle 75 MW Gas Turbine with Baseline NOx of 15 ppm and Controlled to 3 ppm.....	III-26
Table III-19d: Cost Effectiveness for Conventional SCR on Combined Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 142 ppm and Controlled to 15 ppm	III-26
Table III-19e: Cost Effectiveness for Conventional SCR on Combined Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 42 ppm and Controlled to 5 ppm	III-26
Table III-20: Experience and Costs of Ignition Timing Retard (Case Study IC-6)	III-27
Table III-21: Estimated Cost Effectiveness (\$/ton of NOx removed) for Ignition Timing Retard on six 1,100 HP Engines from 10 gm/hp-hr to 9 gm/hp-hr (10% Reduction)	III-27
Table III-22: Estimated Cost Effectiveness (\$/ton of NOx removed) for Injection Timing Retard on six 1,100 HP Engines from 10 gm/hp-hr to 7.5 gm/hp-hr (25% Reduction)	III-28
Table III-23: Estimated Cost Effectiveness (\$/ton of NOx removed) for High Energy Ignition/A-F Ratio Adjustment on four 2,500 HP engines from 15 to 7 gm/hp-hr (53% Reduction)	III-28
Table III-24: Cost Effectiveness for two 3,400 HP IC Gas Engines (low speed) Equipped with Low-Emission Combustion Technology - 77% NOx reduction from 13 gm/hp-hr	III-29
Table III-25: Cost Effectiveness for Four 2,500 HP IC Gas Engines (medium speed) Equipped with Low-Emission Combustion technology - 80% NOx Reduction from 15 gm/hp-hr	III-29
Table III-26: Cost Effectiveness for Four 2,500 HP IC Dual-Fuel Engines Equipped with Low-Emission Combustion Technology - 80% NOx Reduction from 15 gm/hp-hr.....	III-29
Table III-27a: Cost Effectiveness for Three 3130 HP Diesel Engines Equipped with SCR Technology - 90% NOx Reduction from 10 gm/hp-hr	III-31

Table III-27b: Cost Effectiveness for Three 3130 HP Gas-Fired Engines Equipped with SCR Technology - 90% NO _x Reduction from 10 gm/hp-hr	III-31
Table III-27c: Cost Effectiveness for One 1800 HP Diesel Engine Equipped with SCR Technology - 90% NO _x Reduction from 10 gm/hp-hr.....	III-31
Table III-27d: Cost Effectiveness for One 1800 HP Gas-Fired Engine Equipped with SCR Technology - 90% NO _x Reduction from 10 gm/hp-hr	III-31
Table III-28a: Cost Effectiveness for One 1971 HP Diesel Engine Equipped with Mobile-Source Derivative SCR NO _x Reduction System Technology - 75% NO _x Reduction from 7.62 gm/hp-hr	III-32
Table III-28b: Cost Effectiveness for One 1971 HP Diesel Engine Equipped with Mobile-Source Derivative SCR NO _x Reduction System Technology - 75% NO _x Reduction from 15 gm/hp-hr	III-32
Table III-29a: Cost Effectiveness of Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton Clinker on Two 96 Ton/hr. Kilns	III-34
Table III-29b: Cost Effectiveness of Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton Clinker on Two 96 Ton/hr. Kilns	III-34
Table III-29c: Cost Effectiveness of Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton Clinker on Two 96 Ton/hr. Kilns	III-34
Table III-30a: Cost Effectiveness of Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton Clinker on Two 40 Ton/hr Kilns.....	III-35
Table III-30b: Cost Effectiveness of Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton Clinker on Two 40 Ton/hr Kilns.....	III-36
Table III-30c: Cost Effectiveness of Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton Clinker on Two 40 TPH Kilns.....	III-36
Table III-31a: Cost Effectiveness of CemStar - 20% Reduction from 200 lb NO _x /hr/kiln (800 pph total) on Four 40-Ton/hr Wet Process Kilns, Net Clinker Value = \$15/ton	III-37
Table III-31b: Cost Effectiveness of CemStar - 20% Reduction from 200 lb NO _x /hr/kiln (800 pph total) on Four 40-Ton/hr Wet Process Kilns, Net Clinker Value = \$30/ton	III-37
Table III-31c: Cost Effectiveness of CemStar - 20% Reduction from 200 lb NO _x /hr/kiln (800 pph total) on Four 40-Ton/hr Wet Process Kilns, Net Clinker Value = \$50/ton	III-38
Table III-32: Reported Approximate Capital Cost for Urea SNCR System on a Precalciner Kiln	III-38
Table III-33: Cost Effectiveness of SNCR on 150 Ton/hr Precalciner Kiln, 45% NO _x Reduction (from 700 lb/hr to 385 lb/hr)	III-38

I. Executive Summary

This Northeast States for Coordinated Air Use Management (NESCAUM) report evaluates various control technologies and their cost effectiveness in reducing emissions of oxides of nitrogen (NO_x) from four major source categories: industrial boilers, gas turbines, stationary internal combustion engines, and cement kilns. As a group, these sources emit substantial amounts of NO_x in the United States, and for this reason, have been identified by the U.S. Environmental Protection Agency (EPA) and many state and local regulatory agencies as potential sources for NO_x controls. In the recent past, control of NO_x emissions has been required to reduce both the ground-level ozone (NO_x and volatile organic compounds are two major precursors to the formation of ground-level ozone) and acid deposition. Additionally, NO_x emissions contribute to the air pollution problems of fine particles and regional haze (visibility degradation), and to ecological problems including eutrophication of marine bays and estuaries. Further NO_x reductions may be necessary to address these environmental problems in addition to the current focus on ground-level ozone and acid deposition.

A unique feature of this technology assessment report is the detailed description of case studies of actual facilities that are currently using various NO_x control technologies for the four source categories. The case studies provide valuable real-world information on applicability, cost, performance, and reliability of technologies used. This information was useful in determining applicability and cost effectiveness of available control technologies to the four source categories. It is important to note that the conclusions drawn in this study regarding technical and economic feasibility of various control technologies are therefore grounded in “real-world data.”

A. Report Objectives and Organization

This report identifies and evaluates NO_x control technologies that have been commercially applied to the source categories of interest and, based on field experience, assesses the feasibility and cost-effectiveness of applying these technologies to many existing sources that are currently uncontrolled. Case studies were undertaken for actual installations of NO_x reduction technologies on many sources, and detailed write-ups were prepared in cooperation with the users of the technologies. The users provided all of the information and approved the written descriptions of the case studies (Chapter IV). Therefore, these case studies represent the user's view of the performance, reliability, and cost of technologies.

In this report, cost effectiveness is measured in dollars per ton of NO_x removed (\$/ton), and in the case of cement kilns, in terms of dollars per unit of product (\$/ton of clinker) as well as in dollars per ton of NO_x removed. Cost effectiveness is calculated for both annual and seasonal controls (seasonal controls are for the five-month ozone season from May 1 to September 30). Whenever available and appropriate, case study information was used as the basis for the cost analysis.

This report is organized into four chapters. Following this Executive Summary, Chapter II provides a technical description of control technologies that are commercially available. Chapter II also provides a brief background on those technologies that are rapidly emerging, but are not yet

well established. Chapter III deals with the estimates of costs associated with the application of commercially available technologies, including detailed cost effectiveness numbers in \$/ton, as a function of fuel use, capacity factors, and size of the units. Finally, Chapter IV presents twenty-eight case studies of field experience (both operating and cost information) with control technologies described in Chapter II. The cost effectiveness calculations of Chapter III incorporate the field experience of case studies where appropriate.

The following section discusses the most significant findings with regard to the technologies and costs for each source category. The concluding section of the Executive Summary (section C) outlines major findings from case studies experience.

B. NO_x Control Technologies and Cost Effectiveness

Estimates of cost effectiveness are made for both annual and seasonal NO_x control scenarios. In the case of seasonal control, it is assumed that the technology is secured ("turned off"), if feasible, outside of the ozone season to save on the cost of reagents or more expensive fuel. This type of seasonal operation is possible for many secondary control technologies such as Selective Non-Catalytic Reduction (SNCR) or gas reburn. However, most primary control technologies, such as Low-NO_x Burners, provide NO_x reductions all year. When calculating cost effectiveness on a seasonal control basis, no credit is taken for the NO_x reductions outside of the ozone season, since these reductions are not required under current regulations. It should be noted that some states in the Northeast have recently adopted or are seriously considering the adoption of year-round NO_x controls to address other environmental problems such as acid deposition and regional haze. Calculations of cost effectiveness for annual controls are based on the assumption that NO_x reductions occur on year-round operation.

B.1 Industrial Boilers

For industrial boilers, combustion and post-combustion controls are reviewed. Low-NO_x Burners (LNB), overfire air (OFA), Selective Non-Catalytic Reduction (SNCR), Selective Catalytic reduction (SCR), and reburn technology have been used with industrial boilers.

Decisions to use overfire air should be made on a case-by-case basis. Industrial boilers firing pulverized coal that use Low-NO_x Burners without overfire air should be capable of meeting NO_x levels similar to those of utility boilers using similar equipment. Some industrial boilers are not capable of using overfire air and deep combustion staging, although the case studies discuss four boilers that use overfire air as part of a reburning system. For pulverized coal boilers, annual reductions on the order of 30% can be achieved with Low-NO_x Burners at an estimated cost of less than \$2,000/ton, even at a capacity factorⁱ as low as 45%.

ⁱ Capacity factor is a term used frequently in this report to describe the level of operation of the piece of equipment in relation to what the equipment is capable of. Capacity factor is usually expressed as a decimal fraction or a percentage. A capacity factor of 100% (or 1.0) indicates that the equipment is operated at full production capacity for the entire year (8,760 operating hours at full output per year). A capacity factor of 50% (or 0.50) indicates that the equipment is operated at a production level *equivalent to* 50% production capacity for the full year. For example, a 10 MW turbine-generator with a capacity factor of 65% (or 0.65) produces $10 \times 8,760 \times 0.65 = 56,940$ MWhr in one year. While it is

Low-NOx Burners were able to control to a median NOx level of 0.10 lb/MMBTU for industrial boilers firing natural gas, with the substantial majority (over 80%) of these boilers controlling to below 0.15 lb/MMBTU. Boilers equipped with Low-NOx Burners firing number six fuel oil had a median control level of 0.35 lb NOx/MMBTU, with variable performance probably due to the variable nitrogen content of the fuel. Annual NOx reductions with LNBs can be achieved from oil- and gas-fired industrial boilers at an estimated cost effectiveness of about \$2,000/ton or less for moderate to high capacity factors (65 to 85%) units.

SNCR appears to be well suited for use with industrial boilers. SNCR is very widely used on industrial boilers, particularly those firing solid fuels, and achieves NOx reductions of over 50% on average. In boilers firing pulverized coal, NOx reductions with SNCR are likely to be similar to those from utility boilers with SNCR – on the order of 35%. NOx reductions from a boiler firing pulverized coal and equipped with SNCR are estimated to cost in the range of \$1,300 to \$1,800/ton for annual control and from \$2,000 to \$3,000/ton for seasonal controls.

While SCR has seen limited use in the United States on industrial boilers firing solid fuel, there are no technical reasons to believe that SCR cannot be used in these applications. Substantial NOx reductions up to 90% and greater, as achieved with SCR on electric utility boilers, would be expected for pulverized coal-fired industrial boilers. At moderate to high capacity factors, the reductions from industrial boilers are estimated to cost below \$2,000/ton NOx for annual controls. For seasonal controls at moderate to high capacity factors, the range of cost effectiveness varies from \$3,000 to \$5,000 per ton of NOx. SCR on gas-fired boilers is estimated to provide reductions for \$2,000/ton on an annual basis for boilers of about 350 MMBTU/hr size that operate at high capacity factors. Under similar conditions, gas-fired boilers of 100 MMBTU/hr rating can be retrofitted with SCR to provide NOx reductions below \$3,400/ton.

Gas and coal reburn technologies are operating on some industrial boilers in the U.S. and are providing NOx reductions on the order of 50% or more. Combinations of gas reburn with SNCR offer the potential for even higher NOx reduction – 60% or more. Both conventional gas reburn and fuel-lean gas reburn are expected to be more applicable to industrial boilers than is coal reburn. Gas reburn technologies are estimated to provide NOx reductions under \$2,000/ton, even for seasonal controls in some cases. For example, Amine-Enhanced Fuel-Lean Gas Reburn is expected to provide NOx reductions of about 60% on a seasonal basis for about \$2,000/ton or less, assuming an incremental cost of natural gas of up to \$1.00/MMBTU over coal and a capacity factor of 65% or more. The cost-effectiveness values of these technologies, as expected, are sensitive to the price of natural gas relative to the price of coal.

Emerging technologies, such as Electro-Catalytic Oxidation and Ozone Injection offer the potential for high NOx reduction, as well as reduction of the emissions of other pollutants. Because there is much less experience with these technologies, available cost information is limited. Therefore, cost analysis was not performed for these technologies.

acknowledged that equipment production output is usually not at a constant level over the entire year, for the purpose of the calculations in this report this simplifying assumption is made.

B.2 Gas Turbines

There have been some important developments in gas turbine NO_x control technology, but well-established technologies continue to play an important role in reduction of NO_x. Dry Low NO_x (DLN), catalytic combustion, and some new post-combustion methods are making their way into the control technology market, while water or steam injection and SCR continue to be important technologies for reducing NO_x from gas turbines.

Many turbine manufacturers can convert or replace conventional combustors on existing turbines with DLN combustors. DLN combustion retrofits have been made possible by recent developments in gas turbine combustor technology. DLN technology offers the potential for substantial reduction of NO_x from turbines firing natural gas or other low-nitrogen fuels, as well as improved engine performance when compared to wet controls (water or steam injection). For turbines under about 15 MW in size, NO_x emissions of 25 ppm can be guaranteed for new turbines and emissions below 42 ppm can be guaranteed for retrofitted turbines. For large turbines (75 MW and higher in size), controlled NO_x emission levels of as low as 9 ppm have been guaranteed, even for retrofits.

DLN capital costs vary with the size of the turbine and the specifics of the particular turbine being retrofitted. Baseline NO_x level will significantly affect the estimate of cost per ton of NO_x reduced. Using expected baseline NO_x emissions levels provided by the turbine manufacturers and retrofit costs expected to be typical of most applications, retrofit of Dry Low NO_x on industrial turbines (about 3 to 10 MW) originally equipped with conventional combustion control is estimated to provide NO_x reductions under \$2,000/ton for annual controls with high capacity factors and at a higher cost for seasonal controls. For larger turbines (~75 MW), cost was estimated to be well below \$1,000/ton for nearly all conditions, and only a few hundred dollars per ton of NO_x reduced when the turbine was operated at a high capacity factor (~0.85). Calculations show that a DLN retrofit of a large turbine originally equipped with water injection could pay for itself largely from the improved turbine efficiency. If actual baseline turbine emissions are lower than the expected baseline emissions used in these calculations, the cost of reducing NO_x (in \$/ton) will be higher. DLN typically has lower carbon monoxide (CO) and volatile organic compounds (VOC) emissions than water injection.

Water injection and steam injection are two well-established technologies that can offer controlled NO_x emission levels below 42 ppm in many cases. Because water or steam injection technologies frequently have lower capital cost than DLN but higher variable costs, these technologies can be more attractive for peaking turbines or other turbines that operate infrequently. It was estimated that water injection installed on peaking units that operate 200 hours to 400 hours in the summer would reduce NO_x at a cost of about \$2,500/ton to about \$7,000/ton, depending upon the number of operating hours and the fuel used (gas or distillate oil). It is notable that these NO_x reductions typically occur on hot summer days when the value of electrical power and the environmental benefit of NO_x reductions (to reduce ground-level ozone) are both high.

SCR continues to be the most widely used post-combustion technology for gas turbines. Catalyst technology developments have made SCR viable over a wider temperature range. This makes SCR a viable control option in situations that were difficult in the past, such as simple-cycle

turbines that may now benefit from high-temperature SCR and combined-cycle turbines with duct burners that may now benefit from low-temperature SCR.

The cost of NO_x reduction with SCR varies considerably according to application, turbine size, and the type of SCR technology that is appropriate for the application. As in the case of the DLN cost estimates, expected baseline NO_x emissions levels provided by the turbine manufacturers were used as a basis for cost calculations. Conventional SCR on a large (~75MW) combined-cycle turbine with high capacity factors was estimated to cost about \$440/ton for annual controls and \$870/ton for seasonal controls, for turbines equipped with conventional combustion technology (baseline NO_x emissions of 154 ppm). For turbines with lower baseline NO_x emissions (such as those equipped with DLN combustors having baseline NO_x emissions of 15 ppm), the cost per ton of additional NO_x removed was estimated to be greater, ranging from about \$3,700/ton (annual control, high capacity factor) to over \$13,000/ton (seasonal controls, low capacity factor). On smaller turbines (~5 MW), the cost of conventional SCR is estimated to be as low as \$1,300/ton (with annual control and conventional combustion technology having baseline NO_x emissions of 142 ppm). Seasonal controls for smaller turbines are estimated at over \$15,000/ton of NO_x removed at a low capacity factor (45%) with baseline NO_x emissions of 42 ppm.

For installations that may be better suited for high- or low-temperature SCR variants, such as simple-cycle turbines (high-temperature SCR) or combined-cycle turbines with limited space (low-temperature SCR), the cost of SCR is somewhat higher than for conventional SCR on a combined-cycle plant. The analysis of this report found that a 75 MW turbine at a high capacity factor and equipped with conventional combustion technology (baseline NO_x emissions of 154 ppm) can be controlled annually with high- or low-temperature SCR for about \$550/ton and for about \$1,200/ton seasonally. As with conventional SCR, turbines with lower baseline NO_x emissions (such as those equipped with DLN combustors) showed a higher cost per ton of NO_x reduction. The estimated cost of NO_x reduction for a 75 MW turbine with baseline NO_x emissions of 15 ppm ranges from \$5,170/ton (annual controls, high capacity factor of 85%) to as high as \$20,000/ton (seasonal controls, low capacity factor of 45%). On smaller turbines (~5MW), the cost for high- or low-temperature SCR is estimated to be as low as \$2,000/ton with annual control and conventional combustion technology (baseline NO_x emissions of 142 ppm). Cost is estimated to range from \$6,750/ton (annual controls, high capacity factor of 85%) to about \$27,000/ton (seasonal controls, low capacity factor of 45%) with baseline NO_x emissions of 42 ppm.

Emerging combustion technologies (such as catalytic combustion) and post-combustion technologies (such as SCONO_x) offer the potential for very low NO_x emission levels. Because there is much less experience with these technologies, available cost information is limited. Therefore, cost analysis was not performed for these technologies.

B.3 Internal Combustion Engines

Several control technologies are available for internal combustion (IC) engines, having a wide range of complexity, cost and performance.

Some in-cylinder methods offer low to moderate NO_x reductions at costs well below \$1,000/ton. These include injection timing retard, ignition timing retard, and air/fuel ratio adjustment (with or without high-energy ignition). These methods are widely available, and NO_x

performance will vary from one engine design to another. However, fuel efficiency can suffer as a result of these methods and emissions of products of incomplete combustion can increase.

Spark-ignited engines that can be retrofitted with Low-Emission Combustion (LEC) technology can potentially achieve significant NO_x reductions (80 to 90%). LEC technology can be expensive to retrofit on some engines, and it may not be available from all engine manufacturers. For large, low-speed engines, LEC technology is estimated to provide annual NO_x reductions of about 80% at under \$1,000/ton under most conditions. LEC technology is estimated to be more cost effective on smaller, medium-speed engines (under \$500/ton for annual control under most conditions). It is estimated to be somewhat more expensive for dual-fuel engines (annual control at a capacity factor of 65% is estimated to cost under \$1,000/ton).

SCR is the only commercially available choice for post-combustion control of diesel and lean-burn spark-ignition engines. Experience in the U.S. with SCR on these engines is growing, especially for diesel engines. SCR has been applied to approximately 30 diesel engines and to an equivalent number of constant-load lean burn IC engines. Experience with SCR on variable-load engines is limited. In analysis using data from case studies, it was estimated that SCR provides annual NO_x reductions of as high as 90% at a cost below \$1,000/ton in all cases, except for very low capacity factors (~10%), and it provides seasonal reductions at a cost of under \$1,000/ton for engines operating at high capacity factors (typically, 65% or greater).

Recent developments from the application of urea-SCR on mobile sources (diesel trucks) offer the possibility of reducing the size and capital cost of SCR systems for stationary IC engines. This new technology, developed from efforts to apply SCR to mobile diesel engines, appears to make it possible to achieve much more cost-effective NO_x reduction on stationary IC engines that operate for only a few hundreds of hours a year. NO_x reduction of about 75% is estimated to be possible for under \$2,000/ton even for seasonal controls of some stationary IC that operate only a few hundred hours each ozone season. Seasonal control at a cost of under \$1,000/ton is estimated to be achievable for most applications with capacity factor greater than 45%.

B.4 Cement Kilns

Several methods are utilized to control NO_x emissions from cement kilns.

Automated process control has been shown to lower NO_x emissions by moderate amounts, through overall efficiency improvements that reduce the firing requirement in the kiln and by reducing kiln variability, which minimizes periodic NO_x emission spikes. Estimates of cost effectiveness were not made for automated process control due to the lack of availability of data and wide differences that exist between kilns. However, the use of automated process control is expected to improve overall facility operations and is being adopted at cement kilns for its economic benefits.

Low-NO_x Burners have been successfully used in the primary burn zone and especially in the precalciner kilns. Combustion techniques were estimated to provide NO_x reduction at a cost-effectiveness value of under \$1,000/ton (annual control, high capacity factor).

CemStarSM is a process that involves adding steel slag to the kiln, offering moderate levels of NOx reduction by reducing the required burn zone heat input. CemStarSM is currently being used at several cement plants for its original purpose of increasing production capacity. The technology also reduces total NOx emissions by about 20% or more. Because of the increased production, CemStarSM provides an overall economic benefit while reducing total NOx emissions.

Mid-kiln firing of tires provides moderate reductions of NOx emissions while reducing fuel costs and providing an additional revenue stream from receipt of tire tipping fees. Several cement kilns currently employ this technology because of its economic benefits.

Biosolids injection technology can offer significant reductions on some precalciner kilns. There is one biosolids injection plant in the U.S. Biosolids injection offers the potential for tipping fees, but this technology may not be applicable on a wide variety of kilns. Mainly precalciner kilns with sufficient excess fan capacity may be able to use this technology.

SNCR technology has the potential to offer significant reductions on some precalciner kilns. SNCR has been tested on at least one facility in the U.S. However, SNCR is being used in numerous cement kilns in Europe. In situations where SNCR is technically feasible, NOx reductions are estimated to cost under \$1,000/ton, even for seasonal control with capacity factors of about 65% or more.

Many of the control methods discussed in this report for application on cement kilns can be combined. For example, mid-kiln firing and Low-NOx Burners were combined in one case study to provide total NOx reduction of about 50%. It is possible that CemStarSM and process controls could be combined with these technologies for additional reduction and capacity improvement. In some cases it may be feasible to use SNCR in combination with other controls for cement kilns.

C. Case Studies

For all of the case studies, the utilized technologies met the guarantees. In most cases, reliability of control technology to reduce NOx emissions was very good. The few cases where reliability was low (as represented by high lost operating hours) were the result of problems that have since been corrected and are not expected to persist. Therefore, based on the experience of the users in the case studies, future users of the technology are not expected to face reliability problems. For example, some early experience with Dry Low NOx technology on industrial turbines found performance to be unstable during certain transient situations. Some early users experienced frequent tripping of their turbines. Efforts by the turbine manufacturers to improve the Dry Low NOx system controls have overcome the problem, and it should not be a problem for future users.

For industrial boilers, all of the technologies have been demonstrated to have high reliability. A few minor issues were reported, however. There was one instance of tube failure from urea impingement, but the user is correcting the problem with the technology supplier. In another case study plugging of equipment was reported; this is believed to be due to the user's choice of a reagent that does not meet the technology supplier's specifications. Notably, none of the users of SNCR or SCR reported problems normally associated with high ammonia slip, such as ammonium salt deposits on boiler surfaces.

In view of the very limited experience in the U.S. with SCR on IC engines, the high reliability experienced by users in the two case studies is a very positive and promising finding.

For cement kilns, the technologies that were evaluated showed no adverse impact on reliability. In one case study the operator reported that they expect the use of indirect firing to improve kiln reliability. Moreover, cement kiln operators are implementing technologies that both improve facility economics and reduce NO_x emissions by moderate amounts.

II. NO_x Control Technologies

There are four general source categories addressed in this effort: industrial boilers, gas turbines, internal combustion (IC) engines, and cement kilns. Within these four general categories, there are variations in design based on fuel and application. The different variations in each source category are discussed briefly, as they can influence the applicability of a specific control technology. The control technologies that are commercially available for application are then briefly described for each category. Considering the wide variety of source types addressed in this report, there are potentially a wide variety of NO_x reduction technologies available. While this report addresses a number of widely available technology options, technologies that are not currently well established or widely available are only briefly mentioned. Specifically, technologies that have not at least been demonstrated at a commercial scale are not considered in this report.

For those applications and technologies that are addressed in this report, a summary of the important aspects of the application and a brief discussion of the technologies is provided. Readers with an interest in exploring the technical issues in a more comprehensive manner are directed to other sources that are referenced in this report.

A. Industrial Boilers

A wide range of industrial boilers in the United States fire a variety of fuels. The fuels most commonly used in industrial boilers are pulverized coal, crushed coal, oil, natural gas, and biomass (including wood and wood waste). The principal firing types and most common fuels are shown in Table II-1.

Table II-1 Industrial Boiler Firing Configurations and Typical Primary Fuels

Boiler Type	Pulverized Coal	Crushed Coal	Oil	Gas	Biomass
Tangential	✓		✓	✓	
Wall	✓		✓	✓	
Stoker/Grate		✓			✓
Fluid Bed		✓			✓
Cyclone		✓	✓	✓	✓

Tangential- and wall-fired boilers fire pulverized coal, oil or natural gas. Fluidized-bed boilers fire crushed coal and biomass, though they may use oil or gas for initial startup. Cyclone boilers can fire any of the fuels listed except pulverized coal since they generally lack the necessary fuel preparation equipment for firing pulverized coal. Some electric utility cyclone units fire oil or gas, although these boilers were originally built to fire crushed coal. Cyclone boilers in industrial applications, however, most often fire crushed coal and occasionally biomass or other solid fuels.

The NO_x control methods available to industrial boiler operators generally fall into two categories: primary control methods and secondary control methods. Primary control methods

minimize the generation of NO_x itself in the primary combustion zone. Secondary control methods reduce the NO_x originally formed in the primary combustion zone.

A.1 Primary Methods of Controlling NO_x in Industrial Boilers

These methods include the use of Low-NO_x Burners (LNBs), Overfire Air and/or Staged Combustion, and Flue Gas Recirculation. A related method is combustion tempering, in which water is injected into high-temperature regions of the flame.¹ These methods have been explored in detail by others, and Reference ² provides a good overview of the subject. All of these methods operate on the basic principles of controlling fuel/air stoichiometry and flame temperature to lower NO_x generation.

Because of the wide variety of industrial boiler types, firing configurations and fuels, a wide range of controlled NO_x levels are achieved in practice. Wall- and tangentially- fired boilers tend to be most amenable to the use of Low-NO_x Burners, although other primary methods (overfire air, flue-gas recirculation, gas co-firing, etc.) have been used with success on other furnace types. Because of the smaller size of industrial boilers, permitting less separation, overfire air is rarely used. Some have argued that the operating characteristics of industrial boilers make it more difficult to lower the furnace oxygen levels (known as low excess-air) and apply staged combustion as a means to reduce NO_x.^{2,3} Proponents of this argument suggest that industrial boilers have highly variable load characteristics that make combustion controls at low excess-air conditions unworkable. They also note that the size of an industrial boiler makes the length of the Low-NO_x Burner flame too long and that there is insufficient room in the boiler for overfire air.

On the other hand, Low-NO_x Burners and Overfire Air have been successfully applied to many industrial boilers. Reference 2 lists about 400 Low-NO_x Burners installed by one supplier alone, along with their guarantee levels. Chapter IV describes four boilers at Kodak Park (Case Studies BLR-8 and BLR-9) which are using overfire air with reburning, showing that the success achievable in applying primary controls on industrial boilers is determined by the unique characteristics of the facility and the knowledge and skill of the individuals implementing the technology. Despite the differences in facilities, there is a broad selection of primary control methods that may be used at specific units.

For any specific furnace type, the fuel nitrogen, the furnace volumetric heat release rate, and the use of preheated air limit the potential NO_x reductions for primary controls. Other furnace constraints may limit the performance of some technologies as well. Fuel nitrogen content is the primary reason that coal produces much higher NO_x than oil or gas. Coal typically requires higher excess oxygen levels than oil or gas, providing oxygen for thermal NO_x production. The nitrogen content of coal, about 1% to 1.5%, is often double that of residual (No. 6) oil, although nitrogen in residual oil can vary from 0.10% to 0.60%. This range in fuel nitrogen has been a particular problem for boilers firing No. 6 fuel oil, leading to NO_x emissions that may vary from 40 ppm to 310 ppm⁴ and makes it difficult to get predictable reductions from Low-NO_x Burners with this fuel. While manufacturers have successfully found ways to reduce thermal NO_x production, reducing fuel-NO_x requires deep staging in order to first pyrolyze the fuel and then release the fuel-bound nitrogen in a reducing atmosphere. While staged combustion is typically performed with Low-NO_x Burners, deep staging requires more furnace volume than most industrial boilers offer.

Furnace volumetric heat release rate, the degree of air preheat, and the excess oxygen level determine, to a large degree, the combustion gas temperature and the thermal NO_x generated. In-furnace NO_x reduction methods are less effective on high heat release and high preheat furnaces because of the difficulty in overcoming the thermal NO_x component. Although undesirable, reducing the boiler load can be used as a means of addressing this issue if primary and secondary methods prove technically or economically less feasible.

Table II-2 shows a statistical summary of the guaranteed performance of one particular manufacturer's Low-NO_x Burners as reported in Reference 2. Actual performance is typically better. It is interesting to note the standard deviation for both the gaseous fuel and No. 6 fuel oil. For the gas-fired applications, the variation is due to different burner conditions, such as furnace volumetric heat input, preheat level, and different burner designs. For example, flue gas recirculation may be used in some cases for lower NO_x operation. In any event, emissions well below 0.15 lb/MMBTU appear quite achievable with natural gas, probably for well over 80% of gas-fired boilers. In fact, half of the applications reported NO_x below 0.10 lb/MMBTU. In the case of No. 6 fuel oil, NO_x levels below 0.45 lb/MMBTU appear achievable for about 80% or more of the population and below 0.35 lb/MMBTU for half of the population. However, it appears that some boilers would find it difficult to achieve below this level of NO_x control. This is largely because of fuel nitrogen, preheat, and heat release rate. Also, considering that the information summarized in Table II.2 is for burners sold before 1994, performance for more recent applications should be better.

In addition to increasing the temperature of the combustion air, air-preheat increases air velocity at the burner, making a stable flame more difficult to maintain than otherwise. Reference ⁵ describes the use of low-NO_x retrofit technology at industrial boilers firing No. 6 fuel oil with nitrogen content in the range of 0.2-0.4% (by weight). The boilers with preheated air had an initial NO_x level at full load in the range of 0.70 to 0.80 lb/MMBTU. In this case, NO_x was reduced to about 0.40 to 0.50 lb/MMBTU with the low-NO_x boiler retrofit. The other boilers that did not have preheated air had an initial NO_x level of 0.35 lb/MMBTU, and the NO_x emissions from these boilers were reduced to 0.26-0.27 lb/MMBTU. While there are other differences between these boilers beside air-preheat, the use of air-preheat has a significant effect on achievable NO_x emissions. Reference 8 lists an application of the use of deep staging and separated overfire air at a Long Island Lighting power station to achieve NO_x levels of 0.14 lb/MMBTU or less with No. 6 fuel oil. However, this form of combustion control is unlikely to be applicable to most industrial boilers since a large furnace and overfire air are needed to implement deep staging. Generally, the range of NO_x emissions achievable on industrial boilers firing No. 6 fuel oil can vary substantially.

Table II-2: Statistics Regarding Low-NO_x Air Register Burner Performance for Boilers Over ~250 MMBTU/hr^{ii,iii}

	Natural Gas/Refinery Gas (lb NO _x /MMBTU)	No. 6 Fuel Oil (lb NO _x /MMBTU)
Mean Emissions	0.11	0.37
Median Emissions	0.10	0.35
Population Standard Deviation	0.050	0.094
Minimum Emissions	0.05	0.23
Maximum Emissions	0.20	0.55
Analysis based on data from Reference 2 Appendix C.		

Combustion Tempering, also known as Water Injection, is a technique that involves injection of water into the high-temperature and high-oxygen regions of the flame to suppress thermal NO_x formation. This approach has been used on electric utility boilers as well as industrial and commercial boilers.^{6,7} Its effectiveness will vary from one unit to another and will depend on fuels used; however, low to moderate reductions in the range of 15% to 30% should be expected. This method will, generally, be more effective on gas-fired units than units firing No. 6 fuel oil because this method reduces thermal NO_x but not fuel NO_x. For cyclone boilers that generate high levels of thermal NO_x, reductions of 22% have been demonstrated and higher reductions are possible.¹ In most cases, other combustion techniques are attempted first because this approach adversely affects boiler efficiency. Efficiency losses of up to 1% are possible, but lower efficiency losses are typical.

A.2 Secondary Methods of Controlling NO_x in Industrial Boilers

Secondary control methods reduce the NO_x already formed in the primary combustion zone. They include Selective Non-Catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR) and Reburning. These technologies have been applied on a wide range of utility boilers.⁸ Reference 8 contains a comprehensive discussion of these technologies. Summary discussions follow below.

ⁱⁱ Notes for tables II-2, II-3a, and II-3b:

- ♦ The mean is the arithmetic average of all of the NO_x values or reductions reported.
- ♦ The median value is calculated such that 50% of the reported values are higher and 50% are lower than the median. When a population is influenced by a small number of unusually high or low values such that the distribution is somewhat skewed (as in Table 2.2), the median is preferable to the mean as a measure for the population.
- ♦ The Standard Error of Mean is the measure of the uncertainty in using the sample mean to estimate the mean of a large population. When it is small relative to the mean, the mean is a good measure of the population.
- ♦ Population Standard Deviation is a measure of dispersion of a large population.
- ♦ Minimum is the minimum value reported.
- ♦ Maximum is the maximum value reported.

ⁱⁱⁱ The nitrogen content of the No. 6 fuel oil was not available.

Selective Non-Catalytic Reduction (SNCR)

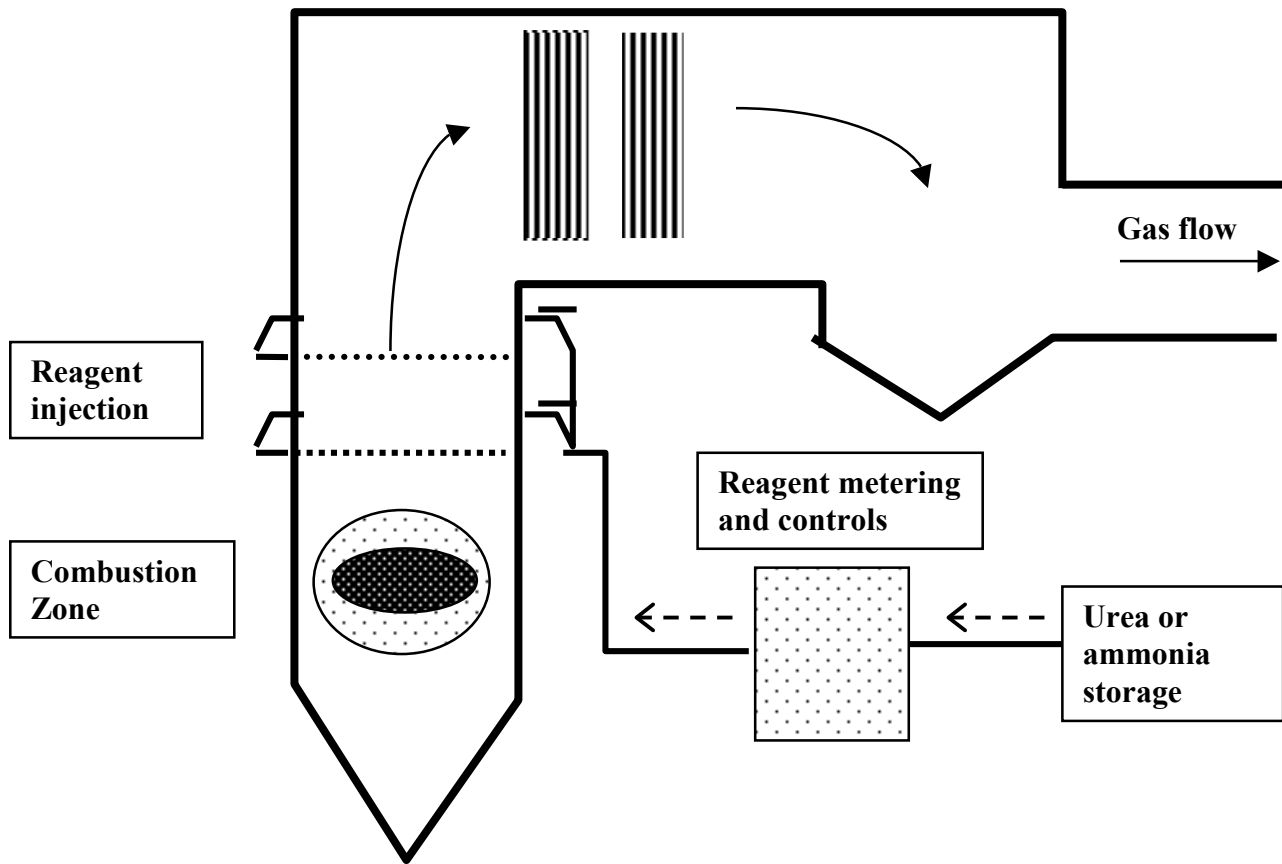
SNCR reduces NO_x through a reaction between urea or ammonia and NO_x in the furnace region (at temperatures of about 1600°F to 2200°F) to produce nitrogen and water. Figure II-1 shows the general scheme for urea SNCR. Aqueous urea, typically 50% by weight, is pumped in a concentrated form through metering pumps or valves to the injection zones in the furnace. Multiple injection zones, each of which may be composed of several injectors, are often needed to address boiler load changes. Dilution water is typically added in order to match the total liquid flow rate to the proper flow rate for the injectors. Ammonia SNCR works similarly, except that the ammonia can be injected in either a gaseous form or as an aqueous solution.

SNCR technology has been used on hundreds of industrial boilers firing a wide range of fuels, including coal, oil, gas, biomass, and municipal waste. The principal determinants of the applicability and achievable performance of SNCR are access for injection of reagent, proper temperature, adequate residence time, and initial NO_x level. Because of the wide range of boiler types among the industrial boiler population, the level of reduction possible through application of SNCR varies widely - from under 20% to over 60%. SNCR tends to become less effective at lower baseline levels of uncontrolled NO_x. For this reason, many gas-fired units find other approaches such as Low-NO_x Burners or SCR more effective. Nevertheless, in some cases SNCR may be effective even on gas-fired units.

The broad applicability of SNCR is illustrated in Tables II.3a and II.3b, which show the types of non-electric utility boilers or process heaters that have been equipped with SNCR and the associated range of NO_x reductions. The information in these tables is representative of the performance of SNCR for lowering NO_x from industrial units. In addition to showing the average NO_x reduction for the facilities, an estimate of the population standard deviation and other statistics were calculated.^{iv} An evaluation of the performance of urea SNCR technology on electric utility units firing mostly coal and, in some cases, firing oil, showed average NO_x reductions of about 39% with an estimated population standard deviation of 16% using a sample of 22 units.⁹ NO_x reductions on utility boilers with this technology are, therefore, significantly less than the NO_x reductions for any of the industrial units identified above. The data for industrial boilers indicate that 50% or higher (in some cases, much higher) NO_x reduction can be achieved on the majority of the industrial boilers. SNCR technology, therefore, seems to be especially well suited for many industrial boilers. It is worth noting that while urea appears to be clearly preferred over ammonia as a reagent for utility SNCR systems (none of the currently operating U.S. utility SNCR systems use ammonia), both urea and ammonia appear to have fairly broad applications in industrial units. Both reagents achieve, on average, over 50% NO_x reduction on industrial units. The choice in reagent depends on the specifics of the industrial application.

^{iv} The population standard deviation is an indication of the dispersion of performance throughout the entire boiler population. The standard error of the mean is an indication of the potential difference between the sample mean (which is used to estimate the mean of the entire population) and the population mean. Statistically, there is less than a 5% chance that the population mean is more than two times the standard error of the mean from the sample mean. For example, if the sample mean is 50% and the standard error of the mean is 3%, there is a 95% chance that the actual population mean is between 44% and 56%. So, a small standard error of the mean relative to the mean gives confidence in the mean as a measure for the population.

Figure II-1: SNCR Applied to a Boiler



Concerns expressed by users regarding the operation of SNCR technology have been primarily directed at the control of ammonia slip and the potential for adverse side effects. Ammonia “slip” refers to the unreacted ammonia that is present in small quantities in the exhaust gases. Ammonia can react with sulfur compounds to form deposits on heat exchange surfaces. Ammonia may contaminate fly ash, or it may contribute to a white plume formed from reaction of ammonia with chlorine that may be present in the fuel. Although early experience with SNCR showed that ammonia slip could be a problem, extensive experience with hundreds of facilities has shown that properly designed and operated SNCR systems can control ammonia slip very effectively. Difficulties with ammonia slip are extremely rare.⁸ A more comprehensive discussion on SNCR and ammonia slip can be found in Reference 8.

Table II-3a: Performance of Industrial Boiler Types Equipped with Urea SNCR ⁹

	Independent Power Producers	Pulp/Paper	Refining	Industrial	Steel Industry
Mean NO _x Reduction	51%	52%	57%	53%	74%
Standard Error of Mean	1.9%	2.4%	3.6%	2.8%	6.2%
Population Standard Deviation	8.3%	7.9%	14.0%	9.7%	20.5%
Minimum	35%	35%	34%	40%	30%
Maximum	70%	62%	74%	70%	90%
Number of Facilities	19	11	15	12	11
Fuels	Biomass, Wood, Coal	Wood waste, wood, pulp, oil, black liquor	Refined Gas, Petroleum Coke, Natural Gas	Coal, No. 6 Fuel Oil	Coal, Natural Gas

Table II-3b: Performance of Industrial Boiler Types Equipped with Ammonia SNCR ¹⁰

	Stoker	Stoker	Circulating Fluidized Bed or Bubbling Bed	Industrial	Refinery Heaters
Average NO _x Reduction	61.7%	57.5%	78.3%	57.7%	58.75%
Standard Error of Mean	2.2 %	3.1%	0.81%	3.5%	3.35%
Population Standard Deviation	7.3%	8.8%	2.1%	11.7%	9.5%
Minimum	57%	46%	76%	30%	43%
Maximum	78%	75%	80%	75%	70%
Number of Facilities	11	8	7	11	8
Fuels	Coal	Biomass	Coal, Biomass	Gas, Oil	Refinery Gas, Natural Gas, Oil

Selective Catalytic Reduction (SCR)

The SCR process (Figure II-2) employs a similar chemical reaction as SNCR, except that the reaction occurs at a much lower temperature (around 650°-700°F) and requires a catalyst. At these low temperatures, SCR is capable of achieving very high NO_x reductions, sometimes in excess of 90%. SCR, however, is more expensive to install than SNCR. Additionally, the catalyst needs to be replaced periodically because of its sensitivity to impurities in the gas stream. In the case of coal-fired boilers, catalysts have been developed that can tolerate coal impurities and provide reasonable catalyst lifetimes (typically, in the range of 14,000-24,000 operating hours before replacing a portion

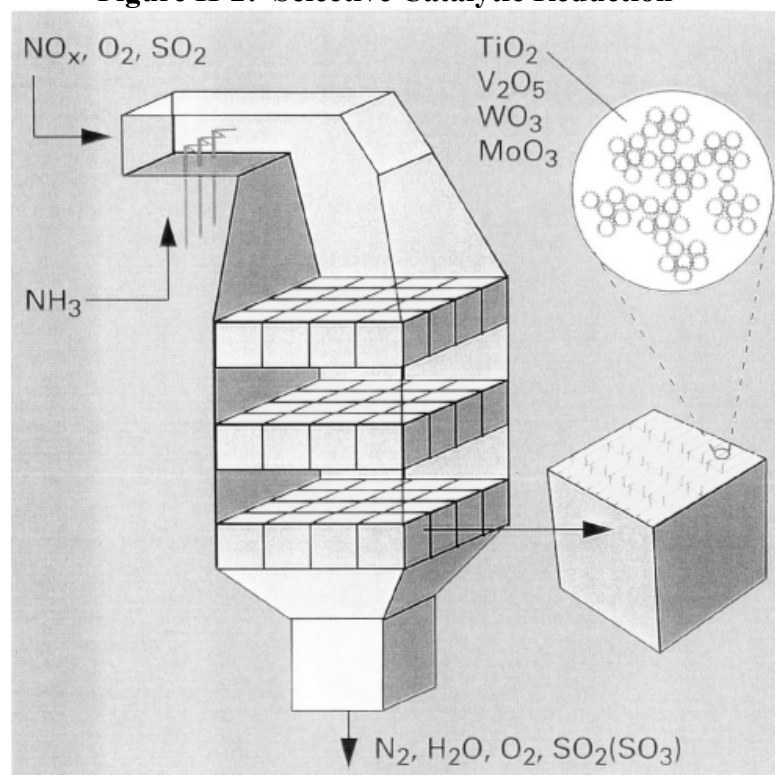
- about 1/4 to 1/3 - of the total catalyst loading).⁸ For cleaner fuels such as natural gas, catalysts lose their activity at a much slower rate, permitting longer times between replacement of catalyst. In Germany and Japan there is extensive SCR experience with industrial boilers firing oil, offering evidence of the applicability of the technology on oil applications firing high-vanadium, high-sulfur oil.⁸

SCR catalysts are available in three general temperature-range categories. Conventional SCR Catalysts operate at a temperature range of about 600°F to 800°F. They are typically used for boilers and are the focus of this section. High-temperature SCR catalysts operate in the temperature range of 800°F to 1,000°F, and are primarily designed for high temperatures associated with the exhaust gases of simple-cycle gas turbines. They are discussed later in Section B.2. Low-temperature SCR catalysts (250°F to 500°F) have been designed for use in a variety of applications, including industrial boilers and combined-cycle gas turbines firing relatively clean fuels. These systems offer the advantage of being able to simplify installation by reducing the degree of boiler or system integration necessary to incorporate the SCR catalyst reactor into the facility. The supplier of the technology, KTI, reported fifteen commercial systems installed and two on order at the time of this writing, in addition to the conventional SCR applications listed by Institute of Clean Air Companies (ICAC).^{11,12}

SCR has been extensively used to control NO_x from hundreds of utility and industrial boilers in Japan and Germany, and several coal and gas-fired utility boilers in the United States. The ICAC reported twelve industrial boilers operating with SCR in the U.S., all firing natural gas or refinery gas (except one boiler firing wood waste).¹² Fifteen refinery process heaters were also identified. SCR is considered technically feasible for nearly all types of industrial boilers.

The principal technical concerns expressed by industry regarding SCR deal primarily with ammonia slip and catalyst deactivation. Ammonia slip from an SCR system is the same as for an SNCR system. However, ammonia slip from an SCR system is much easier to control to low levels than for SNCR. Problems with ammonia slip from SCR systems are extremely rare.⁸ Catalyst deactivation occurs as a result of impurities in the gas stream that can produce blinding deposits or poisoning of the catalyst material. Although catalyst deactivation occurs, the rate of catalyst deactivation has not proven to be a problem for coals and certainly not for natural gas. An outstanding issue remains regarding the use of low-sulfur, high-calcium western coals with SCR. These coals are unique to the U.S. and there is no experience with SCR on facilities firing these coals. Catalyst suppliers agree that these coals can produce deposits that deactivate the catalyst, but one supplier states that the rate of catalyst deactivation is expected to be within an acceptable range for commercial use.¹³ Commercial experience with these coals on electric utility boilers that have recently commenced operation with SCR will shed more light on this question.

Figure II-2: Selective Catalytic Reduction¹⁴



Reburning

Reburning operates by creating a fuel-rich reducing region downstream of the primary combustion zone that reduces the NO_x formed in the primary combustion zone. Several types of reburning systems can be used with industrial boilers, including conventional reburning, Fuel-Lean Gas Reburning (FLGR), Amine-Enhanced FLGR (AEFLGR), and Methane DeNO_x. In the case of conventional reburning, a burn-out zone is necessary downstream of the reburn zone because the entire reburn zone is made fuel rich, requiring completion air to avoid high emissions of products of incomplete combustion (Figure II-3). For Fuel-Lean Gas Reburning (FLGR), a downstream burnout zone is not needed (Figure II-4). Most experience with reburning is on electric utility boilers using natural gas as the reburn fuel, although there are industrial boilers that employ the technology.⁸ Coal-fired industrial boilers at Kodak Park in Rochester (New York) are equipped with conventional reburning. Three boilers on the site are equipped with gas reburning and one boiler is equipped with micronized coal reburning. NO_x reductions of over 50% have been achieved from the gas reburning systems, and the micronized coal reburning system achieves over 50% reduction at full load and lower reductions at part load (Case Study BLR-9, Chapter IV). Although reburning may not be widely applicable to industrial boilers, it is commercially employed on industrial boilers at Kodak Park and is probably applicable to many other industrial boilers.

Fuel-Lean Gas Reburning (FLGR) has been demonstrated or applied commercially to several electric utility boilers, including roof-fired boilers, wall-fired boilers, tangentially-fired boilers, cyclone boilers, and turbo furnaces. It typically is capable of about 30% to 40% NO_x reduction on most facilities and the level of NO_x reduction normally becomes limited by increased emissions of

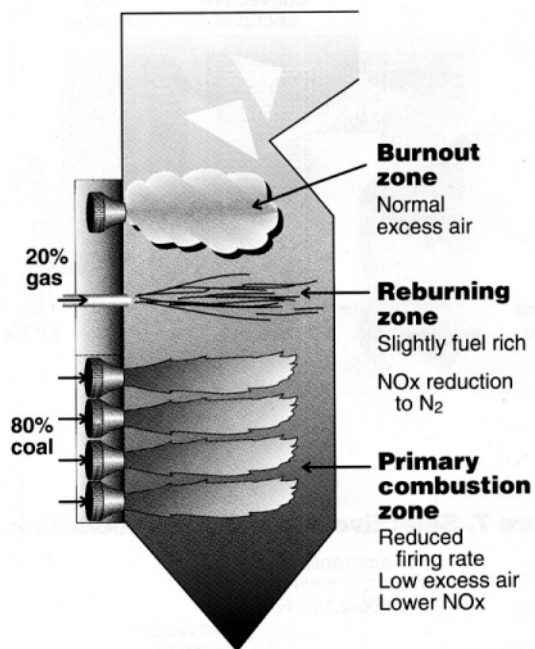
CO. Unlike conventional gas reburning, which typically requires 15% to over 20% of the furnace heat input to be in the reburn zone, FLGR requires typically only 4% to about 7% of the heat input from natural gas. This makes FLGR much less costly to operate. Moreover, FLGR does not require overfire air, which adds expense to a conventional gas reburn system and may also prevent application of conventional reburn to some small boilers. Hence, there may be some industrial boilers that can benefit from FLGR technology but not from conventional reburn.

FLGR and SNCR can be used as separate systems or can be integrated to create an Amine Enhanced (AEFLGR) system. AEFLGR is being used commercially on coal-fired utility boilers to produce NO_x reductions of 60% (on average) and up to 70%.¹⁵

Methane DeNO_x is another technology that uses the principals of reburning and is applicable to grate- and stoker-fired boilers. Natural gas and recirculated flue gas are injected above the grate to form a reducing zone while overfire air above the gas ports burns out the combustibles. Methane DeNO_x is in operation on four boilers at a Cogentrix facility near Richmond, VA.¹⁶

Although any fuel can potentially be used for the reburn fuel, natural gas is preferred because it burns more easily than coal or oil and also because it results in zero fuel-NO_x emissions. The main disadvantage of natural gas as a reburn fuel is that it is typically more expensive than coal, and it is not available at all locations. Coal has been used in the U.S. as a reburning fuel on one of the Kodak cyclone boilers; however, coal reburn systems tend to require more expensive equipment than gas reburn systems.

Figure II-3: Conventional Gas Reburning



The primary technical concerns expressed by industry regarding these technologies are impacts on boiler tube corrosion, and impacts on unburned carbon (also known as Loss Of Ignition,

or LOI) and CO emissions. Experience with numerous long-term demonstration programs and commercial plants indicates that reburning does not accelerate boiler tube corrosion.⁸ Increased CO emissions and LOI tend to limit the level of NO_x reduction achievable. Commercial reburning systems have been installed and are currently operating on utility and industrial boilers while maintaining CO and LOI within acceptable levels.⁸

Electro-Catalytic Oxidation (ECO)

Electro-Catalytic Oxidation is an emerging technology for reduction of NO_x and other pollutants. In the ECO process, NO_x and other pollutants (SO₂, mercury, and VOCs) are oxidized in a dielectric barrier discharge reactor located immediately after the electrostatic precipitator (ESP) and prior to a wet ESP. Since NO_x is oxidized to nitric acid, it is readily removed from gases by the wet ESP. SO₂ is similarly converted to sulfuric acid and removed. The ECO process is shown schematically in Figure II-5. It is being field tested on a coal fired utility boiler in Ohio.

Low-Temperature Oxidation using Ozone

Low-temperature oxidation using ozone is another emerging technology that operates by oxidizing NO_x and SO₂ to acids and then removing the acids out in a wet scrubber. Ozone used in the process is produced on site. The technology has been tested on a coal-fired electric utility boiler and is being tested on a gas-fired industrial boiler. In both cases the technology has been demonstrated to reduce NO_x to below 2 ppm.¹⁷

Figure II-4: Fuel-Lean Gas Reburning

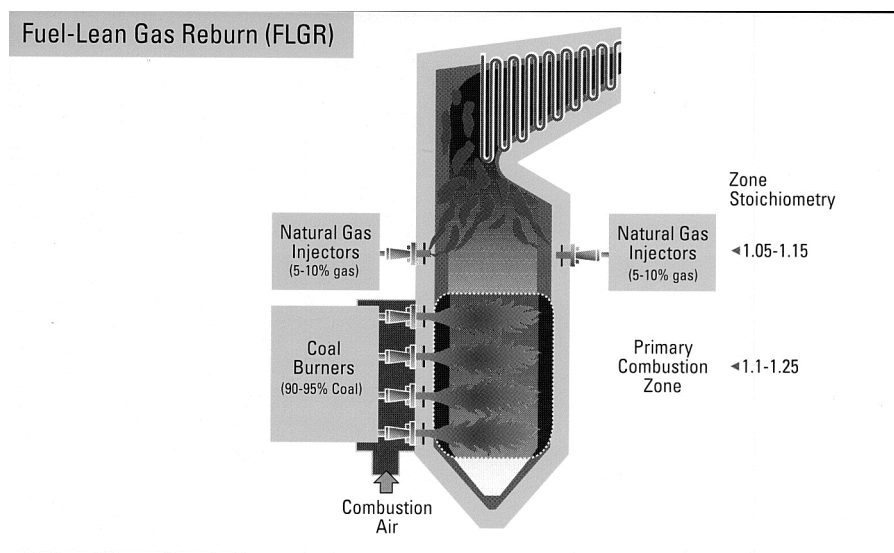
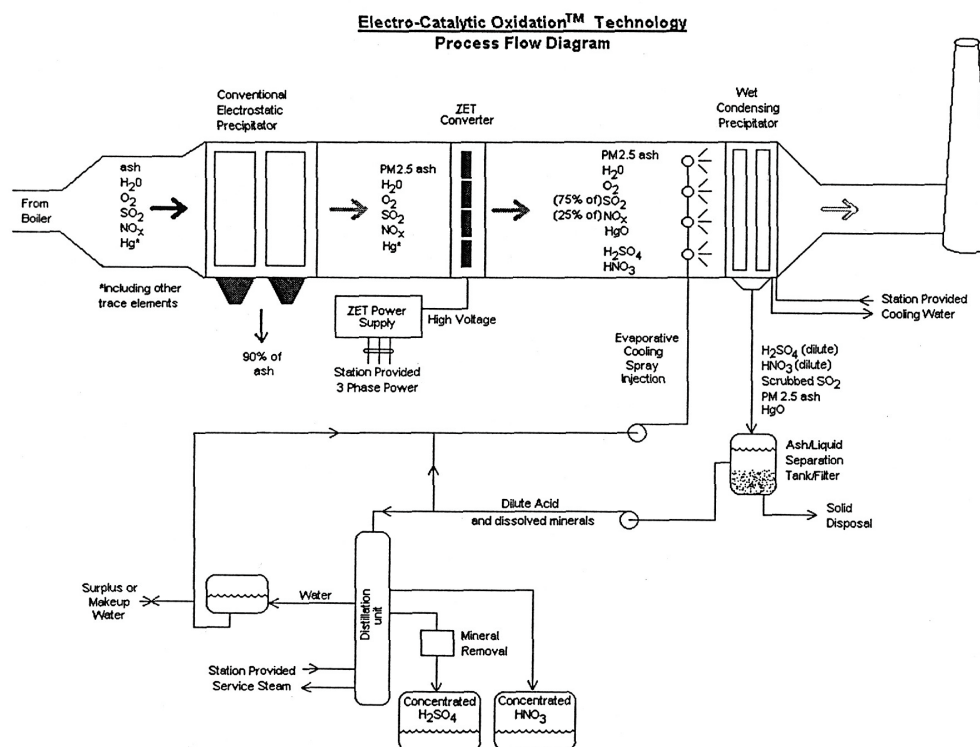


Figure II-5: Electro-Catalytic Oxidation Technology¹⁸



B. Gas Turbines

Gas turbines fire gaseous fuels (natural gas, waste gas, landfill gas, etc.) and/or distillate oil. Gas turbines use primary (or in-combustor) methods that minimize the production of NO_x in the gas turbine combustor and secondary control methods that reduce the NO_x that has been formed. Reference ¹⁹ provides a comprehensive overview of these technologies. A brief summary follows.

B.1 Primary Methods of Controlling NO_x from Gas Turbines

Dry Low NO_x (DLN)

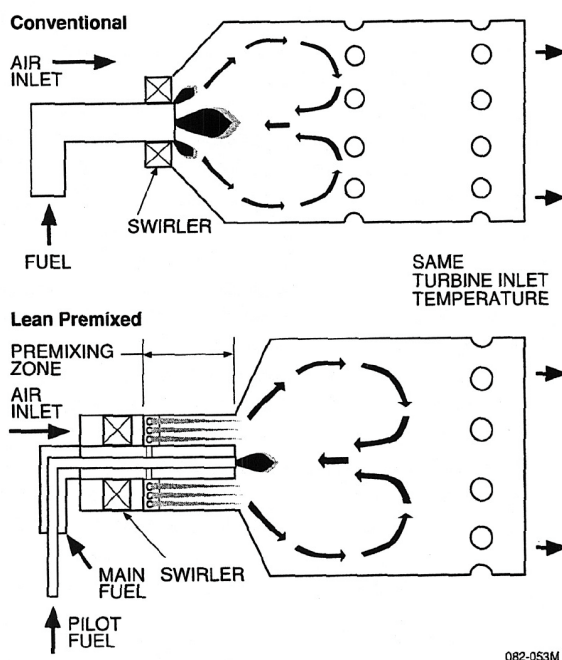
DLN is a gas-turbine combustion technology that enables gas-turbine combustors to produce low NO_x emission levels without diluents (such as water or steam) or catalysts. Some suppliers offer combustors on new turbines that are capable of NO_x emissions under 9 ppm_{dv} (parts per million dry volume basis) at 15% oxygen when firing natural gas.^{19, 20} DLN technology utilizes a lean, premixed flame as opposed to a turbulent diffusion flame, therefore typically requiring the use of natural gas. Other fuels that can be premixed might be used, although use of fuels other than gas is rare. Since fuel oil cannot be easily premixed, it is not typically suitable as a DLN fuel. Turbulent diffusion flames are common for boilers and for gas turbines that do not utilize DLN technology. Figure II-6 compares a DLN (lean-premixed) combustor to a conventional gas turbine combustor. As indicated in the figure, in a lean, premixed combustor, the fuel and air are premixed prior to

entering the combustion zone. With a lean, premixed flame, the contribution of prompt^v and thermal NOx can be much lower than for a turbulent diffusion flame. The contribution of fuel NOx is minimized through the use of low-nitrogen fuels, such as natural gas. Achieving low NOx across the full load range requires a sophisticated combustor design, often with variable operating modes in order to maintain flame stability. Not all turbine designs can accommodate a DLN combustor. However, most turbine suppliers have developed the ability to retrofit the existing turbines in the field.

There has been a learning curve in the field implementation of this technology. Because Dry Low NOx combustor technology operates under conditions that are much closer to the flammability limit than the conventional combustor technology, there is a significant risk of flame instability. In fact, some early experience with this technology found that flameouts were frequent under varying weather or load conditions (see case studies in Chapter IV). However, manufacturers have developed improved electronic turbine controls that have addressed this problem. Some early experience also found combustor liners failing after only about 5,000 hours (see case studies), compared to over 20,000 hour lifetime for conventional technology. Again, the turbine manufacturers have addressed this problem by improving the lifetime of the DLN combustor liners to a lifetime similar to, and in some cases longer than, that of conventional combustion technology.

Solar Turbine Company reports that they have retrofitted about 50 turbines with their SoLoNOxTM Dry Low NOx technology, with achieved reductions shown in Table II-4a. Current technology from this manufacturer achieves 25 ppm.²¹ Additionally, over 500 new turbines from this manufacturer are operating with DLN technology.

Figure II-6: Comparison of a Lean Premixed Combustor and a Conventional Combustor²¹



^v There are three types of NOx formation: Fuel NOx, generated by oxidation of fuel nitrogen; Thermal NOx, generated from direct oxidation of nitrogen in the combustion air; and Prompt NOx, generated by oxidation of HCN intermediates formed in the combustion air by nitrogen fixation to hydrocarbon radicals in fuel-rich combustion zones.

Table II-4a: NO_x Performance of Solar Industrial Gas Turbines with SoLoNO_xTM Dry Low NO_x Combustor²²

Turbine Model	Power (MW)	Pre-Control Emissions (ppm)	Post-Control Emissions (ppm)*	% Reduction
Mars 100	10	240	42	83%
Mars 90	9	178	42	76%
Taurus 60	5.25	143	42	71%
Centaur 50	3.5	105	42	60%
Centaur 40	3	130	42	68%
* These are results from retrofit installations only. Current DLN technology from this manufacturer can achieve 25 ppm on new turbines Other turbine suppliers, such as Allison, also offer DLN technology on their products in this size range				

Solar manufactures gas turbines up to about 16 MW in size. Even lower NO_x levels are possible with DLN technology on larger gas turbines available from other suppliers. New and retrofit turbines in the larger, power plant sizes (over 50 MW) have been retrofitted to below 9 ppm of NO_x. Table II-4b below lists larger turbines that are available with DLN or can be retrofitted with DLN.

A DLN retrofit, however, is not appropriate for all situations. Figure II-7 shows a turbine comparing a DLN combustor to a standard combustor. The DLN combustor is typically larger than a conventional combustor and may not fit on some older turbines. In some cases it may be economically more attractive to replace the old turbine with a new one due to the extent of the modifications necessary to convert the existing turbine. DLN combustors also can have more limited operating ranges than conventional combustors. Turbines likely to experience frequent and rapid load changes may experience a brief spike in NO_x emissions with DLN technology. If these turbines must also comply with hourly average NO_x emission requirements, DLN may not be the best approach. Moreover, some turbines require the use of distillate fuel during some periods. The NO_x reduction benefit of DLN is achievable with fuels that can be premixed and are low in fuel nitrogen content, such as natural gas. Therefore, turbines that must maintain low NO_x levels while operating on fuel oil may find other technologies more appropriate. Nevertheless, despite these considerations that can limit the applicability of DLN technology, DLN retrofit technology is available for the majority of turbine types.

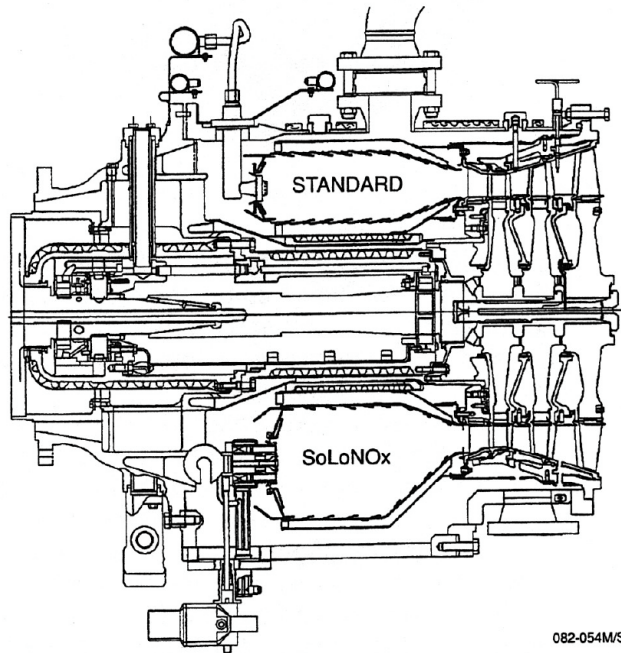
Table II-4b: NO_x Performance of Large Gas Turbines with Dry Low NO_x ¹⁹

Turbine Model	Manufacturer	Power (MW)	Pre-Control Emissions (ppm)	Post-Control Emissions (ppm)*	% Reduction
MS 6001B	GE	39	148	25/9*	83+
MS7001E	GE	84	154	25/9*	84+
MS7001F	GE	161	210	25	88
MS9001E	GE	125	161	25/9*	84+
MS9001F	GE	229	210	25	88
GT10	ABB	22.6	150	25	84
GT11	ABB	83.3	390	25/9*	94+
V84.2	Siemens	22	212	25/9*	88+
V94.2	Siemens	153	212	9	86
V64.3	Siemens	61.5	380	42	89
V84.3	Siemens	141	380	42	89
V94.3	Siemens	204	380	42	89
* In some cases, 9 ppm limits are offered as retrofit guarantees, in other cases these guarantees may only be available for new turbines.					

Diluent Injection

Injection of water or steam into the combustor has been used to reduce flame temperature and reduce NO_x emissions. This is normally achieved with a special fuel injector that permits co-injection of fuel and the diluent. Diluent Injection can be used with any fuel. Steam injection is useful only on applications where a boiler is present, such as Combined Cycle Gas Turbines (CCGT's). Steam injection does not impose as significant a heat rate penalty as water injection, roughly 1% versus 3 to 4%. Diluent may also be injected in the form of a fuel-oil/water emulsion, but this is not a common approach. In general, increased flow rate of diluent will decrease NO_x. The amount of diluent that can be injected is limited by permissible carbon monoxide emissions and by impact to turbine wear. Therefore, the level of NO_x reduction possible will depend upon the particulars of the turbine. Diluent injection systems are available from most gas turbine manufacturers.¹⁹ Reference 19 lists various turbines and manufacturer's guarantees for performance. According to Reference 19, for turbines firing natural gas, water/steam -to-fuel ratios range from 0.33 to 2.48 and achieve controlled NO_x emission levels ranging from 25 to 75 ppm at 15% oxygen. When firing distillate oil, water/steam-to-fuel ratios range from 0.46 to 2.28 and achieve controlled NO_x emission levels ranging from 42 to 110 ppm at 15% oxygen.

Figure II-7: Solar Turbines' SoLoNOx™ DLN and Standard Combustor with Conventional Combustion Technology²¹



A benefit of diluent injection is an increase in turbine power output that results from the higher mass flow through the turbine. This increase in power is generally of the order of a few percent. Depending upon the capabilities of the generator, compressor, or other device being driven by the turbine and the capability of turbine auxiliaries, this additional power may or may not be useful. Counter to the power benefit, diluent injection adversely impacts the efficiency of the gas turbine and increases wear on the turbine and combustor. Moreover, the consumption of water can be very high for a large turbine, sometimes more than double the fuel flow rate. Such high water usage may pose problems for the local water supply and is an added expense. However, where very low NO_x levels are required while firing fuel oil or for peaking turbines, diluent injection may be a technically more appropriate technology choice than DLN. Additionally, due to the lower capital cost of diluent injection, it may be an economically more attractive approach than DLN for turbine applications that only operate for a few hours per year.

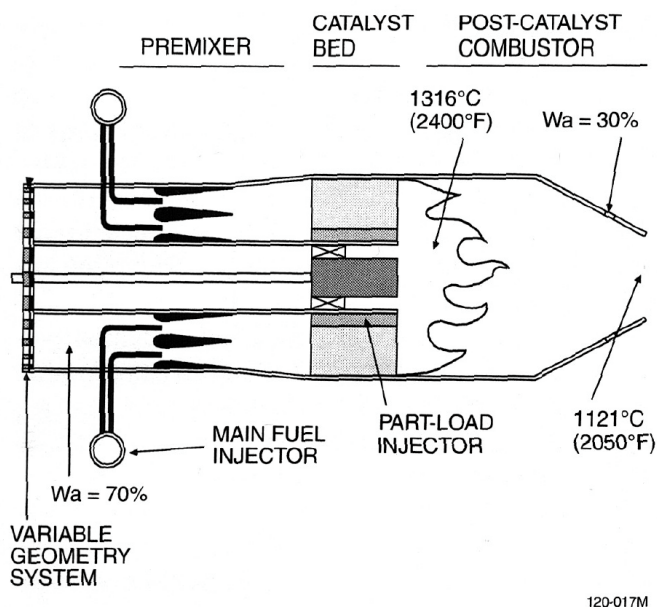
Simple-cycle turbines require high-purity water and can therefore be somewhat more expensive to retrofit with this technology than combined-cycle turbines. Combined-cycle power plants generally have water treatment on site to service the boiler but simple cycle facilities do not normally have water treatment on site.

Catalytic Combustion

Catalytic Combustion is an emerging technology that may evolve as a retrofit technology for existing turbines, and is expected to be developed for new turbines in coming years. Catalytic combustion reduces NO_x formed from the combustion process by reducing the combustion

temperature to reduce thermal NO_x. Figure II-8 presents a schematic of a catalytic gas turbine combustor. The technology has been demonstrated on small gas turbines (about 5 MW). According to Catalytica, a developer of catalytic combustion who has business relationships with several turbine manufacturers, this technology has been demonstrated to achieve 3 ppm NO_x on a 1.5 MW Kawasaki gas turbine. A NO_x level of 3.3 ppm was achieved on a General Electric Frame 9 test stand.²³ These results show that this technology appears to be capable of achieving NO_x levels comparable to those achievable when commercially available combustor methods, such as diluent injection or Dry Low NO_x, are used in combination with post-combustion methods (such as SCR).

Figure II-8: Schematic of a Catalytic Gas Turbine Combustor²⁴



B.2 Secondary Methods of Controlling NO_x from Gas Turbines

As noted earlier, secondary control methods reduce NO_x originally formed in the primary combustion zone. Two methods to accomplish this are described below.

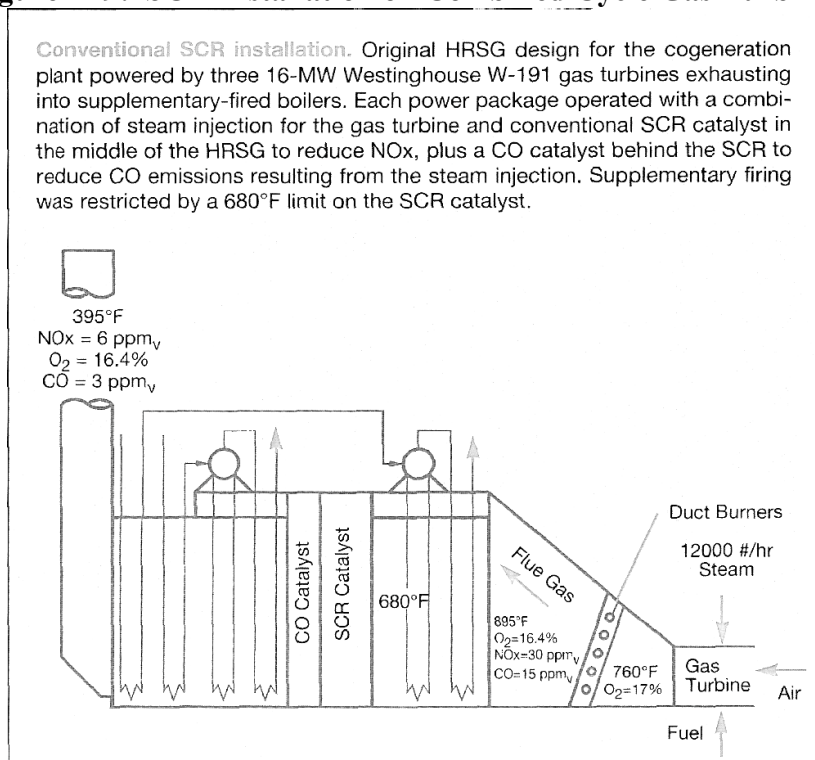
Selective Catalytic Reduction (SCR)

SCR is the exhaust treatment technology most widely used on gas turbines. It is being required on many new gas turbine installations, especially those that are equipped with Heat Recovery Steam Generators (HRSG). SCR operates no differently on gas turbines than on boilers, as was described in Section A.2. Gas turbines equipped with SCR have been guaranteed to 2 ppm NO_x.

There are over 150 commercial installations of SCR on gas turbines in the United States,¹² nearly all on Combined-Cycle Gas Turbine (CCGT) plants. On combined cycle plants, the catalyst is normally installed in a cavity within the HRSG (Figure II-9), which is designed to provide the proper gas temperature and flow through the catalyst. For simple cycle applications, the SCR is installed at the turbine exhaust. Although standard turbine exhaust temperature is usually higher than most conventional catalysts will permit, some catalyst suppliers have developed catalysts that

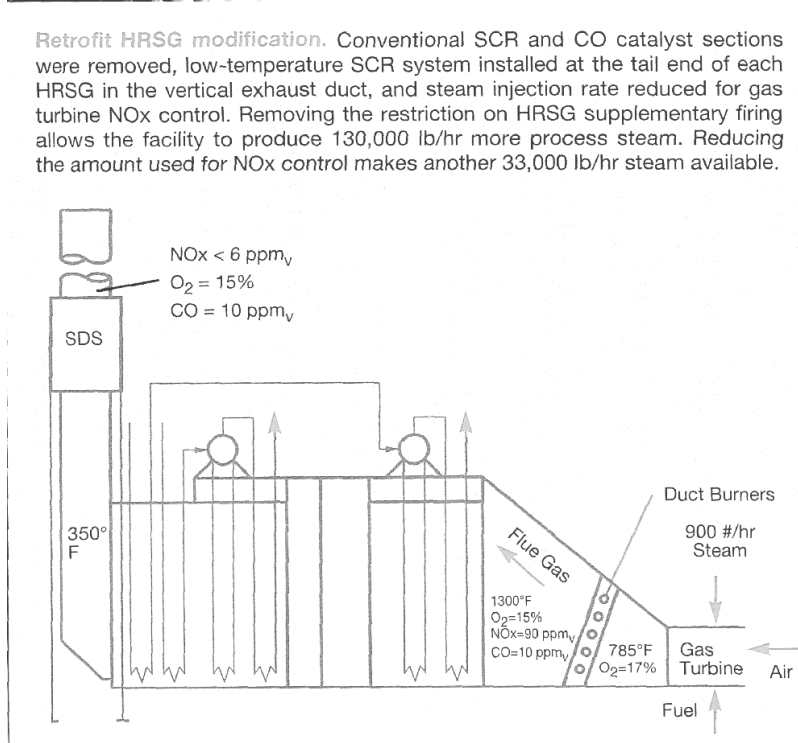
can perform in the environment of the high-temperature simple-cycle turbine exhaust. These "High-Temperature" SCR applications require expanded, internally insulated ductwork to act as the transition region from the turbine exhaust to the stack.²⁵ Although the large majority of gas turbine SCR installations are on combined cycle plants, there are a small number of SCR installations on simple cycle plants or upstream of the HRSG. For example, three Solar Centaur Type H simple cycle gas turbines, each rated at 5,500 hp, are equipped with high-temperature SCR at the Southern California Gas Company, Wheeler Ridge Station in Valencia, CA.²⁶

Figure II-9: SCR Installation on Combined Cycle Gas Turbine²⁷



For many situations, low-temperature SCR offers the potential for a simpler installation than a conventional SCR. Rather than requiring an HRSG with a cavity, the catalyst reactor can be installed at the tail end of the system, as in Figure II-10. Although Figure II-10 shows an HRSG with a cavity for a catalyst, with the low-temperature catalyst, a simpler HRSG design would be possible. This low-temperature catalyst, which was developed by a division of Shell Oil Company, is sometimes referred to as the "Shell DeNO_x System," or SDS. In the event that the facility had an existing HRSG without a cavity, the low-temperature SCR could be installed without any need to modify the HRSG. Moreover, there are other benefits with this approach, such as increased distance between the duct burner and the SCR catalyst. This allows improved duct burner firing, permitting higher steam production rates.

Figure II-10: Low-Temperature SCR Installed on a Combined Cycle Gas Turbine
(Also known as the “Shell DeNO_x System” (or SDS, as it is labeled in the Figure), this SCR
was developed by a division of Shell Oil Company.²⁷⁾



In principle, SCR can be used downstream of any form of primary control technology to produce extremely low levels of NO_x, but some obstacles do exist. Diluent steam or water injection can be used in the combustor to reduce NO_x formation, but the moisture can somewhat inhibit the SCR reaction and will increase the gas flow rate. Therefore, when using diluent injection in combination with SCR to achieve low NO_x levels, SCR suppliers must account for the effects of the high water content of the exhaust gas. In some situations this may result in higher ammonia slip, shorter catalyst lifetimes, or may require larger catalyst volumes.

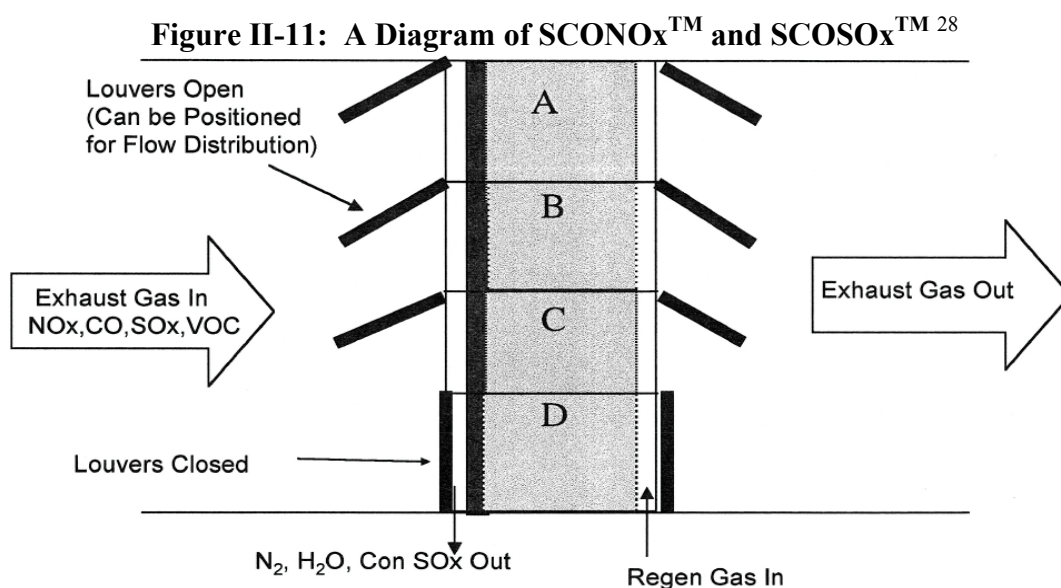
A great deal of attention has recently been focused on ammonia slip. Allowable ammonia slip varies by application and also by facility permit requirements, but is rarely more than 10 ppm, and typically much less. Ammonia slip limitations and guarantees are frequently of the order of 2 ppm or less. The catalyst volume, catalyst lifetime, and maximum allowable ammonia slip at the end of the SCR life can be varied based upon the control requirements and economic tradeoffs. In normal operations, ammonia slip from an SCR system is very low - typically well below 1 ppm - for the first several years of SCR operation. Generally, the ammonia slip will begin to approach a guarantee level only after the catalyst activity deteriorates somewhat, usually after several years. For clean fuel applications such as natural gas, many years (often six or more) typically pass before the catalyst activity is diminished to a point where the ammonia slip begins to approach the guarantee level.

SCONoxTM

SCONoxTM is an emerging catalytic sorbent technology that has recently been offered for commercial use. The principal advantage of SCONox over SCR is that it does not require the use or storage of ammonia. With SCONox, NO_x is oxidized in the presence of a platinum-based catalyst and the resulting NO₂ is adsorbed onto a potassium carbonate sorbent. The sorbent must be regenerated periodically with hydrogen from an on-site hydrogen reformer that consumes steam and natural gas (methane). The sorbent and catalyst also need periodic replacement. SCOSOx (also supplied by the vendor and required to remove SO₂ to avoid poisoning the catalyst used in SCONox)) removes SO₂ in the same manner as SCONox (oxidation-adsorption-regeneration) and is normally used upstream of the SCONox system. This is because even natural gas has small quantities of SO₂ that would poison the downstream SCONox catalyst. The SCOSOx portion of the system must be regenerated in a similar manner as the SCONox system. By-products from regenerating the SCONox and SCOSOx sorbents are ducted downstream of the system. SCONox also oxidizes carbon monoxide to carbon dioxide.

The system is installed as a bed of sorbent/catalyst (Figure II-11). A system of louvers and piping allows portions of the bed to oxidize and adsorb pollutants and other portions of the bed to undergo regeneration.

SCONox has two current installations. The demonstration of this technology at a commercial scale was on a gas turbine in Vernon, CA (established as Lowest Achievable Emission Rate (LAER) by EPA Region 9, San Francisco). The developer reported that the technology achieved NO_x emissions to below 2 ppm NO_x (a reduction of over 90%). The owner of this facility, Sun Law Federal Cogeneration, is also affiliated with the developer of the technology, Goal Line Technologies. The second application of this technology on a commercial scale was on a ~5 MW gas turbine installed in Andover, Massachusetts, and operations commenced in summer of 1999.²⁸ Because of the limited experience with SCONox relative to other available technologies, there is only limited information available on actual experience with catalyst or sorbent life, the use of consumables (such as steam and gas) or overall reliability.



Although SCONOx has been applied only to gas turbines, it is expected that the technology will be applicable to other clean-fuel applications such as gas-fired boilers. Products of diesel engine combustion have been shown to deteriorate the catalyst by sulfur masking during tests.²⁹ Therefore, SCONOx may not be applicable to systems firing fuels other than natural gas or very high-quality distillate fuel oil that is very low in sulfur.

C. Internal Combustion (IC) Engines

Internal Combustion Engines are generally of two types: Compression Ignition (CI, or Diesel) or Spark Ignition (SI). CI engines typically fire fuel oil while SI engines are fueled with gaseous or volatile liquid fuels, such as gasoline. Whereas all CI engines fire in a fuel-lean mode, SI engines can operate under fuel-lean conditions or under stoichiometric to slightly fuel-rich conditions. Most large SI engines (over about 1,000 hp) are of the fuel-lean type and therefore are of greater interest than the smaller SI engines that are generally not major sources of NOx. Rich-burn stationary IC engines are most common at natural gas production facilities.

NOx reduction from IC engines is possible with either in-cylinder methods or exhaust treatment methods. Primary, or in-cylinder methods, minimize the amount of NOx formed itself. Exhaust treatment methods reduce the NOx originally formed in the cylinder.

C.1 Primary Methods of Controlling NOx from IC Engines

Primary methods of controlling NOx involve controlling the combustion process in the cylinder to minimize NOx formation. They involve controlling or modifying the combustion that occurs in the cylinder, and include injection/ignition timing retard, air/fuel ratio changes, and a Low Emission Combustion (LEC) retrofit using a pre chamber.

Injection Timing Retard

For CI engines, retarding the injection timing by about 4 degrees can reduce NOx by 15-30%. With this retard, the fuel ignites entirely during expansion rather than igniting initially during compression and then mostly igniting during expansion. This results in lower combustion temperature and lower thermal NOx, but also in increased fuel consumption. Moreover, some engines may have problems with high CO and soot emissions as a result of these changes. The modification for injection timing retard can be performed with a very low capital cost, and may also require a few hours of a mechanics time. Often some additional hardware or testing is recommended, bringing the total cost to a few thousand dollars. However, this adjustment is not possible on all engines.

Ignition Timing Retard

Ignition timing retard is applicable to SI engines and works on the same principle as injection timing retard. NOx reductions from ignition timing retard are similar to those achieved from injection timing retard, and modifications can be performed with very low capital costs and a few hours of a mechanics time. Again, some additional hardware or testing is recommended, bringing the total cost to a few thousand dollars. SI engines, however, are generally more sensitive to timing retard than CI engines, and they will have more operational problems when it is employed.

Therefore the level of NO_x reduction achievable for SI engines can be more limited than for CI engines.

Air/Fuel Ratio Changes

NO_x formation from a spark-ignited engine is highest when the mixture is slightly fuel-lean. Richer or leaner mixtures will result in lower NO_x. Fuel-lean mixtures are preferred to fuel-rich mixtures because fuel consumption is reduced and hydrocarbon emissions are less likely to be a problem. However, leaner mixtures are more prone to misfire. A richer mixture, on the other hand, will often require the addition of an exhaust treatment technology because of the higher hydrocarbon emissions that are likely to result. Leaning the mixture is normally performed in combination with ignition system improvements, such as high-energy ignition (increasing spark voltage) to avoid misfiring problems. Leaning is also frequently done in combination with Low Emission Combustion Retrofits (described below) to enhance NO_x reduction from that technology. An air/fuel ratio change can normally be done at a modest cost because it requires an engine adjustment, and occasionally a limited amount of additional hardware.

Low Emission Combustion (LEC) Retrofit

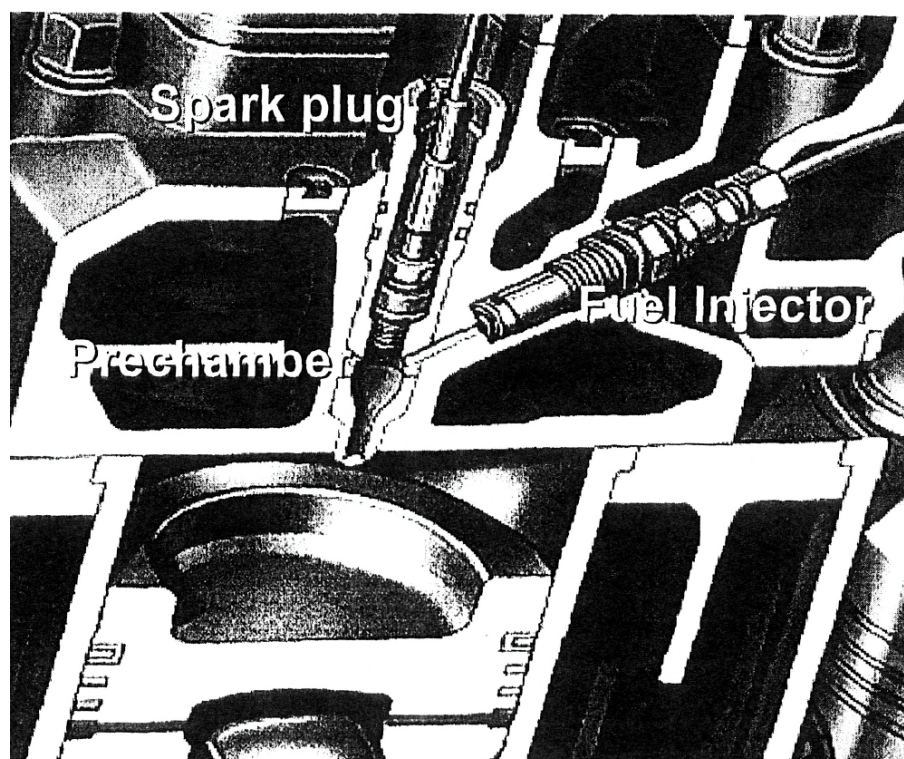
This method can in principle be used on all spark-ignition engines, but some manufacturers may not offer it. LEC enhances the effectiveness of the air/fuel ratio method previously discussed by enabling much deeper leaning without the other adverse effects associated with lean mixtures. On large engines this method is typically employed by relocating the spark plug to a pre chamber where the mixture is somewhat richer than in the cylinder. This early sparking avoids problems associated with ignition and misfiring that can result from leaning the mixture. This method normally requires a significant modification to the engine heads. The extent of the modifications will depend largely on the particular engine and the manufacturer of the LEC Retrofit kit. Figure II-12 shows a LEC retrofit kit from Waukesha Engine Company.

According to Reference ³⁰, large, stationary spark-ignition engines usually achieve 80% NO_x reduction through a LEC Retrofit. A NO_x emission level of 125 ppm (at 15% oxygen) is an achievable exhaust NO_x value, and Reference 30 considers LEC Retrofit a Reasonably Available Control Technology (RACT) for large spark-ignition engines in California.

C.2 Secondary Methods of Controlling NO_x from IC Engines

Exhaust treatments from lean-burn IC engines are less common than for gas turbines. This may be because IC engines are usually smaller in total output than turbines. Few IC engines exceed 10,000 HP, with most engines of interest in the range from few hundreds to few thousands of horsepower. Turbines, on the other hand, can have outputs that exceed 100 MW (133,000 HP).

Figure II-12: Pre Chamber Low Emission Combustion Retrofit³⁰



Selective Catalytic Reduction (SCR)

SCR is the only commercially proven secondary NO_x reduction method for lean-burn gas engines and diesel engines. It has not been used widely, however, because of general preference for in-cylinder methods (in-cylinder methods, however, result in lower level of NO_x reductions). Reference 12 lists seven IC (gas or diesel) engine facilities comprising 29 engines equipped with SCR. Some installations (17 engines in all) have been in operation since 1992. NO_x reductions on these systems are reported to range from 80 to 95%. Engines with highly variable duty cycles may face challenges with SCR use. Variable duty cycles result in exhaust temperatures that may fall outside the ideal catalyst temperature and result in variable NO_x emission that require correspondingly variable ammonia flow rates. Reference³¹ argues that applying SCR to lean-burn engines firing natural gas, particularly those used for natural gas transmission, is technically inappropriate. According to Reference 31, in a survey of pipeline engines that use NO_x control, only 2 of 599 lean-burn gas-transmission engines surveyed use SCR (both in California). And, according to Reference 31, most of the difficulty in using this technology is associated with the variable operating conditions of these engines, which pose control difficulties for the SCR system and also increases the risk of lube oil residuals masking the catalyst.

Beyond its high level of achievable NO_x reduction, SCR offers some advantages over some in-cylinder methods of controlling NO_x from IC engines. First, SCR imposes a relatively small efficiency penalty on an engine (on the order of 0.5%) compared to penalties of a few percent and substantially less level of NO_x control from in-cylinder methods such as timing retard. Moreover, some of the in-cylinder methods can increase the emissions of other pollutants, such as unburned

hydrocarbons, CO, and in the case of diesel engines, soot. Finally, SCR is generally less expensive than LEC Retrofits.

Larger combustion systems such as gas turbines or boilers have primarily used catalysts of ceramic monolith or ceramic-coated steel. Due to their smaller size, IC engines also use metal washcoat catalysts. These catalysts tend to be much more expensive per cubic foot than ceramic monolith catalysts, but have much more catalytic activity per cubic foot, making the net cost about the same as for the other catalyst types. Metal washcoat catalysts are effective with natural gas or diesels using distillate fuel oil, but are unsuitable for dusty abrasive gases, such as those formed from burning coal. Finally, metal washcoat catalysts can withstand engine backfires more effectively than ceramic monolith catalysts

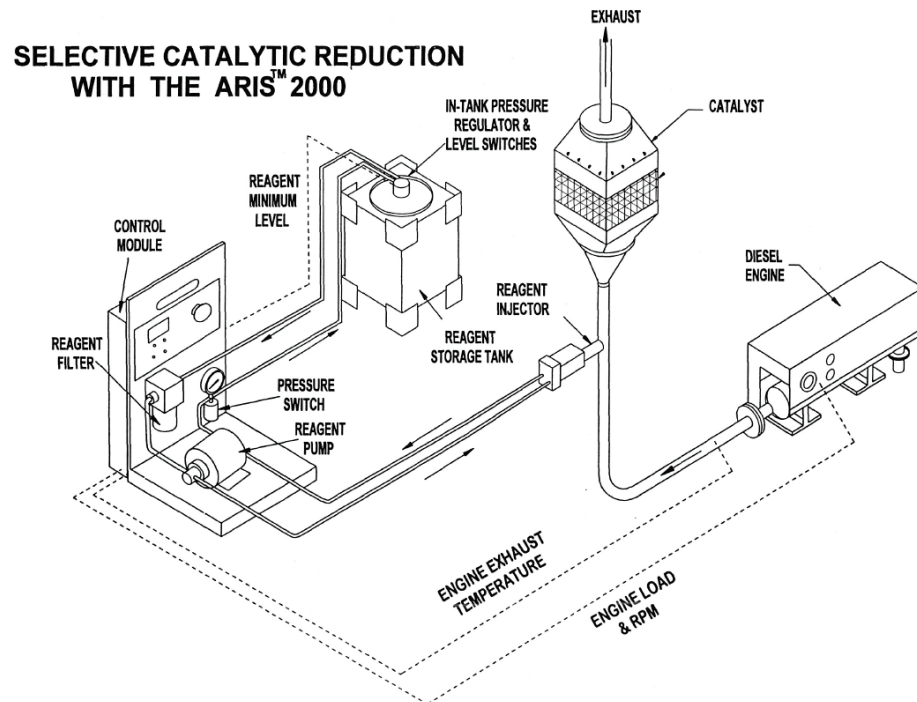
Because SCR technology was, to a large extent, originally developed for facilities such as boilers and gas turbines, SCR technology on IC engines has relied on controls and injection hardware originally developed for these larger applications. This mismatch has resulted in fairly high cost of SCR relative to the system size for IC engines. Recent efforts, however, in SCR development for mobile sources (diesel trucks) have focused on simplifying the control and injection hardware for SCR applications to stationary IC engines, offering the potential for much more cost-effective application of this control technology to stationary IC engines.

Figure II-13 shows a technology developed by Clean Diesel Technologies, Inc. to reduce the cost of applying SCR to IC engines, especially diesel engines. The system takes signals from the engine such as load, exhaust pressure, inlet manifold pressure, etc., and injects an appropriate amount of aqueous urea reagent into the exhaust manifold upstream of the exhaust catalyst. Flow of urea is controlled by pulsing the fuel, which recirculates in a constant pressure recirculation loop. The urea injector has a very similar design to a fuel injector.

NO_x emissions are not directly measured by the control system, so it is necessary to first carefully characterize the engine emissions relative to the monitored parameters. The quality of the engine performance map that is needed is dependent upon the level of required NO_x reduction. Therefore, in order to retrofit this technology onto an existing engine, it is necessary to perform some testing and data gathering to generate this engine performance map. In cases where the engine performance is not highly reliable or repeatable, such as for an old or poorly maintained engine, lower reductions may be achievable. For example, only a 75% NO_x reduction may be achievable from an old engine and a higher 90% reduction from a new engine, depending on the relative quality of the performance map.

The SCR technology shown in Figure II-13 was originally developed for mobile source (diesel trucks) applications, using urea as a reagent. The first commercial application of this technology on a U.S. stationary source was on a lubricant test engine at the development facilities of a major U.S. oil company.³² In this application, both diesel- and gas-fired engines were equipped with this technology, achieving 82% and 92% reductions, respectively.

Figure II-13: Urea SCR System (ARIS™ 2000) for IC Engines ³³

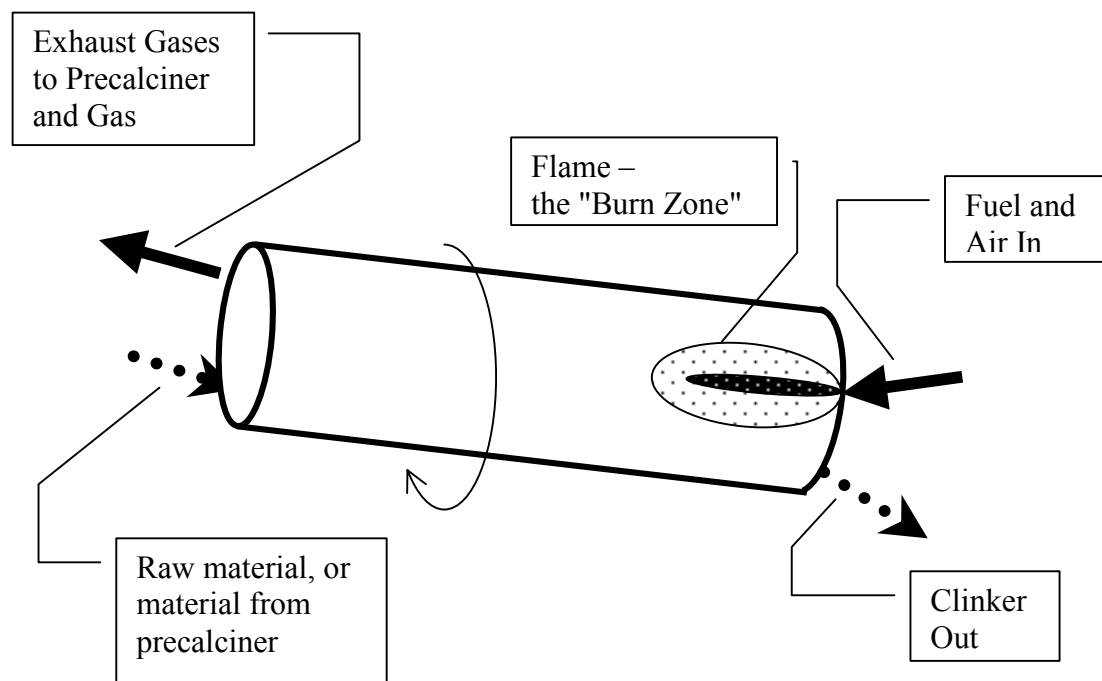


Case study IC-1 (Chapter IV) uses SCR with controls that rely on engine parameters for reducing NO_x. The engine parameter controls make continuous measurements of NO_x emissions unnecessary. This control system (from another supplier) also requires engine mapping. However, unlike the system shown in Figure II-13, it utilizes conventional ammonia injection technology.

D. Cement Kilns

Concrete is a combination of Portland Cement, sand, and gravel. The key component of Portland Cement is clinker, a material produced by heating limestone to temperatures over 2,650°F, requiring combustion temperatures of about 3,000°F. These high temperatures are normally achieved in a rotary kiln, as shown in Figure II-14. Feed material is added at the elevated end of the rotating, refractory-lined, cylindrical kiln and the feed gradually tumbles to the high-temperature end of the kiln and the main combustion zone, sometimes referred to as the "Burn Zone." The tilted design of the cement kiln allows gravity to assist the motion of the clinker material while hot exhaust gases move upward and exit at the elevated end of the kiln.

Figure II-14. Simplified Sketch of a Rotary Kiln



Cement Kilns fall into four general process categories, as identified in Table II-5. Preheater kilns preheat and partially calcine feed material in a series of cyclones or grates prior to admitting the feed to the rotary kiln. This additional heat supplements the heat in the exhaust from the kiln. The calcined feed then enters the rotary kiln at about 1,500°F to 1,650°F. Precalciner kilns, on the other hand, utilize a burner in a separate vessel along with a series of cyclones or grates to preheat and calcine the feed. Preheater and precalciner kilns are more energy efficient than long wet or long dry kilns and also typically have greater capacity. Figure II-15 shows a precalciner kiln equipped with five cyclonic preheaters. A preheater kiln is similar, but fuel is not added and there is no burner on the cyclonic preheater portion. Preheaters could also be replaced with suspension preheaters, but these are less common. Long wet and long dry kilns do not have preheaters and have much longer rotary kilns, with wet process kilns being the longest - normally several hundred feet long.

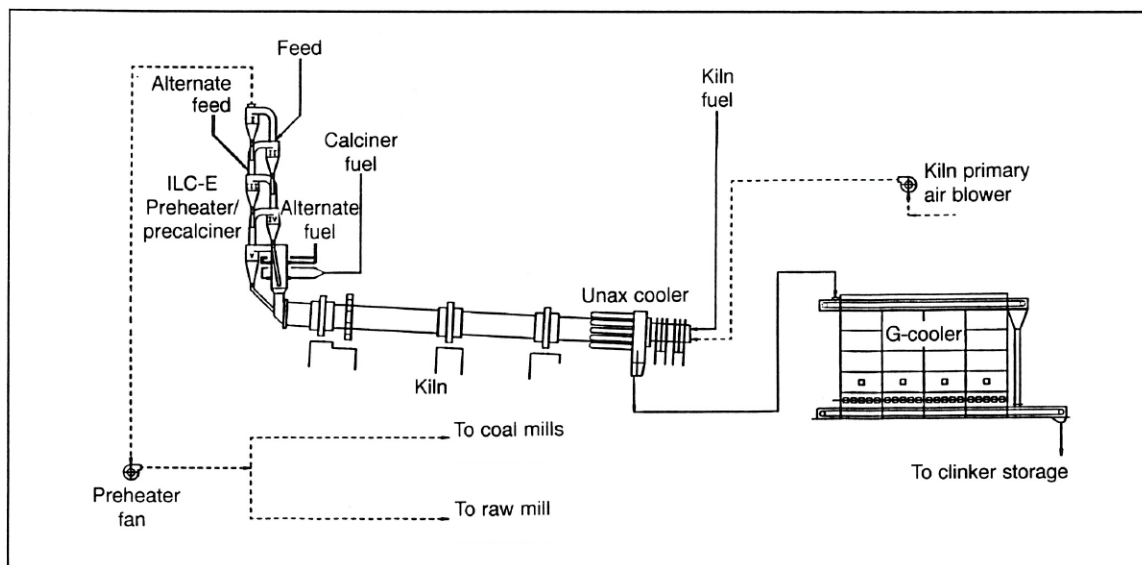
Table II-5: Summary of Cement Kiln Process Types in U.S. ³⁴

Kiln Type	Number of Kilns	Total Annual US Capacity (1,000 metric tons)	Average Per-Kiln Annual Capacity (1,000 metric tons)
Wet Kilns	70	20,797	297
Long Dry Kilns	66	16,933	256
Preheater Kilns	37	15,148	409
Precalciner Kilns	27	23,774	880
Total	200	77,652	388 (avg.)

Coal is the fuel of choice in cement kilns, primarily because of its low cost, but also because the coal ash contributes somewhat to the product. In 1997, 82% of the fuel used in cement kilns was coal, 4% was natural gas, and 14% were other fuels, mainly combustible waste (industrial waste, tires, sewage sludge, etc.). Fuel nitrogen therefore contributes a small but significant amount to the total NO_x for nearly all cement kiln applications. However, as will be discussed in Section D.1, despite coal's higher nitrogen content, this fuel usually results in lower NO_x than natural gas when burned in the primary burn zone despite its higher nitrogen content.

Thermal NO_x dominates fuel NO_x in cement kilns. At the high temperatures required in the Burn Zone, nitrogen and oxygen in air combine to form NO_x, regardless of the source of heat. The thermodynamic equilibrium NO_x level at 3,000°F and 1% oxygen is about 1,500 ppm. The heat input required for cement kilns, however, can vary with the characteristics of the local raw feed. Cement kilns process local limestone deposits, and the mineral's characteristics will vary between locations and may even vary at a particular location. Limestone's mineral properties affect the level of heating necessary to process the material, and thereby affect the level of NO_x produced. Changes in residence time and other kiln adjustments can also decrease NO_x concentrations, thus, two kilns of similar design may produce different NO_x emissions. Finally, NO_x emissions vary across kiln types. Long wet kilns tend to have the highest heat input per ton of clinker (typically, about 6 MMBTU per ton), while long dry kilns use somewhat less heat (about 4.5 MMBTU per ton), and preheater and precalciner kilns use even less heat, and these kilns create correspondingly variable levels of thermal NO_x (Figure II-16). This variability in NO_x emissions from kilns provides a challenge to control NO_x emissions from cement kilns.³⁹

Figure II-15: A Precalciner Cement Kiln with Five-Stage Cyclonic Preheater/Precalciner³⁵



Since 1973, the amount of annual clinker capacity in the U.S. and Canada has remained relatively stable at about 75,000-80,000 tons, with most new capacity coming from kilns of the dry process type. In response to demand for cement, the industry is adding new capacity at this time. Between 1973 and 1997, the average capacity per kiln increased from about 170,000 metric tons per year to 388,000 metric tons per year, corresponding to a reduction of the total number of kilns from

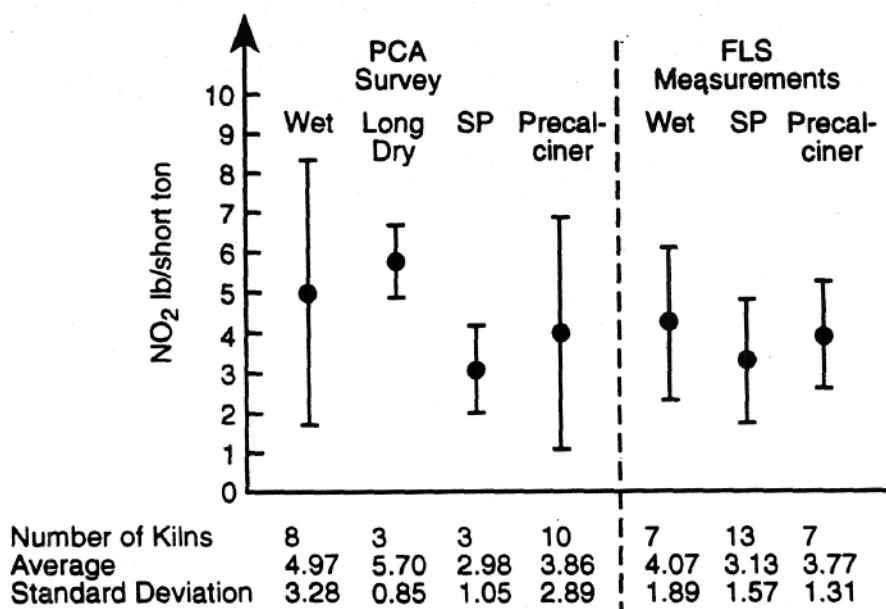
nearly 450 small kilns to 200 larger kilns.³⁶ Many of these larger kilns employ precalciner kilns because they are the newest technology, have the largest capacity, and are more efficient than the older technologies. If past trends continue, many of the existing wet kilns and long dry kilns are expected to be replaced with precalciner kilns.

Recent years have seen Portland Cement plant capacity stretched by high demand, making technologies that can increase capacity without increased capital expenditures very attractive. The industry is therefore developing technologies that improve facility's outputs or reduce their operating costs. Conveniently, some of these technologies also offer the potential to reduce NO_x emissions.

D.1 Primary Methods of Controlling NO_x from Cement Kilns

The quality of clinker produced in a kiln varies with characteristics of the combustion; therefore primary controls need to be selected carefully. Dry Low NO_x, for example, has seen varied levels of success. The main firing zone of the kiln requires very high temperatures and is not compatible with the lower flame temperature used by DLN to reduce NO_x. Low excess air and air staging are problematic control options for kilns because the kilns need an oxidizing environment not provided by those techniques. Despite these problems, indirect firing in combination with a Low-NO_x Burner has been successfully used in some facilities, including California Portland Cement (Case Study CK-1 in Chapter IV). Low-NO_x combustion methods can be used in the precalciner because high temperatures are not required in that part of the process.

Figure II-16: NO_x Emissions for Various Cement Kiln Types³⁷
SP is Suspension Preheater kilns



Switching to a lower nitrogen fuel may not reduce NO_x emissions. In fact, switching from coal to natural gas will rarely help to reduce NO_x emissions and will likely cause NO_x emissions to increase. The luminous flame of a coal burner is more effective in heating the solid material than a relatively transparent natural gas flame, requiring less total heat when firing coal. The furnace gas temperature, therefore, is lower for a coal flame than for a natural gas flame for the same solid

material throughput. Hence, less thermal NO_x is generated when firing coal, and the lower nitrogen content of natural gas does not make up for the higher thermal NO_x in the natural gas flame. Natural gas fuel may be useful in reducing NO_x from precalciner kilns, however, because the temperature in the precalciner is much lower, reducing the impact of thermal NO_x.

Lo- NO_x Burners (LNBs) with Indirect Firing

Indirect firing is a method that permits use of LNBs in the primary kiln burning zone. When indirect firing is used, pulverized coal is fed to and collected in a particulate matter collection system (a cyclone separator that exhausts gas through a fabric filter). The pulverized coal is then temporarily stored in a bin or hopper, where it is fed to the burner. This method allows less primary air to be used in the burner than with a direct-fired coal mill, resulting in less thermal NO_x.

LNBs can be used when indirect firing is employed. When implementing indirect firing with LNBs, other process improvements are often implemented, such as better process controls. Reference 39 mentions that 20%-30% NO_x reductions can be achieved from the use of indirect firing with LNBs and associated process modifications. Indirect firing is used in Case Study CK-1 (Chapter IV).

Low-NO_x Precalciners

Precalciner kilns can employ LNBs because the temperature in the precalciner is low enough to reduce thermal NO_x. Since roughly 60% of the fuel burned in a precalciner kiln is fired in the precalciner, NO_x reductions can be substantial. All new precalciner kilns are equipped with Low-NO_x Burners in the precalciner. Low-NO_x precalciners have been shown to reduce NO_x by 30%-40% compared to conventional precalciners.³⁸ This reduction is from the precalciner-generated NO_x, not for the entire kiln.

Mid-Kiln Firing

Mid-kiln firing entails injecting a fuel, usually tires, mid-way through long dry and long wet kilns. This method has been shown to reduce NO_x by about 30% with mid-kiln heat input comprising about 20% of the total heat input.³⁹ Reference⁴⁰ provides results of tests of mid-kiln firing on several kilns as summarized in Table II-6. The average NO_x reduction for these kilns is about 27%. Mid-kiln firing reduces the heat needed, and therefore the thermal NO_x produced, in the primary burn zone. Fuel NO_x will also be reduced because tires and other mid-kiln fuels have low nitrogen contents. Nitrogen content in tires is roughly one fifth that of coal on a mass basis, while heating value on a mass basis is similar.⁴¹ Coal can be used as a mid-kiln firing fuel, but tires are preferable because they provide a revenue source when kiln operators are paid a tipping fee for taking whole tires. Other revenue-generating fuels could potentially be used as well.⁴²

The mid-kiln combustion process can be sensitive and must be controlled properly. Reference 42 describes the results of a trial burn of a mid-kiln firing system where about 10% reduction in NO_x was achieved, but CO emissions increased from about 50% to about 75% over baseline levels. Results have typically been better than this, and the addition of mixing air (discussed below) will address potential increases in CO emissions. Mixing air injected between the tire injection point and the feed inlet (the gas exit) makes it possible to address concerns regarding CO emissions and make further reductions in NO_x. This technique is similar to overfire air on boilers, introducing the fuel to reduce NO_x further with much less risk of high CO emissions.

Mixing air generally permits better combustion control and more consistent (and, generally lower) NOx emissions. Figures II-17a and II-17b show the effects of mixing air in reducing the variability of NOx, eliminating the highest values and resulting in an overall lower average NOx level.

Table II-6: NOx Reduction at Cement Kilns Using Mid-Kiln Technology ⁴⁰

Initial NOx (ppm)	936	1372	1342	1359	565	513
Final NOx (ppm)	790	994	600	883	488	456
% Reduction	16%	28%	55%	35%	14%	11%

Mid-kiln firing can be combined with other approaches, such as indirect firing. Case study CK-1 in Chapter IV discusses the use of mid-kiln firing in combination with indirect firing to achieve combined NOx reductions of nearly 50%. In case study CK-1, it was determined that mid-kiln firing reduced facility production by 10% with a tire addition rate equivalent to a 12% (BTU basis) fuel substitution rate. It is uncertain at this time if the reduced production experienced at the California Portland Cement should be considered typical.

Figure II-17a: Frequency of NOx Values on Cement Kiln with Mid-Kiln Tire Injection (Without Mixing Air) ⁴⁰

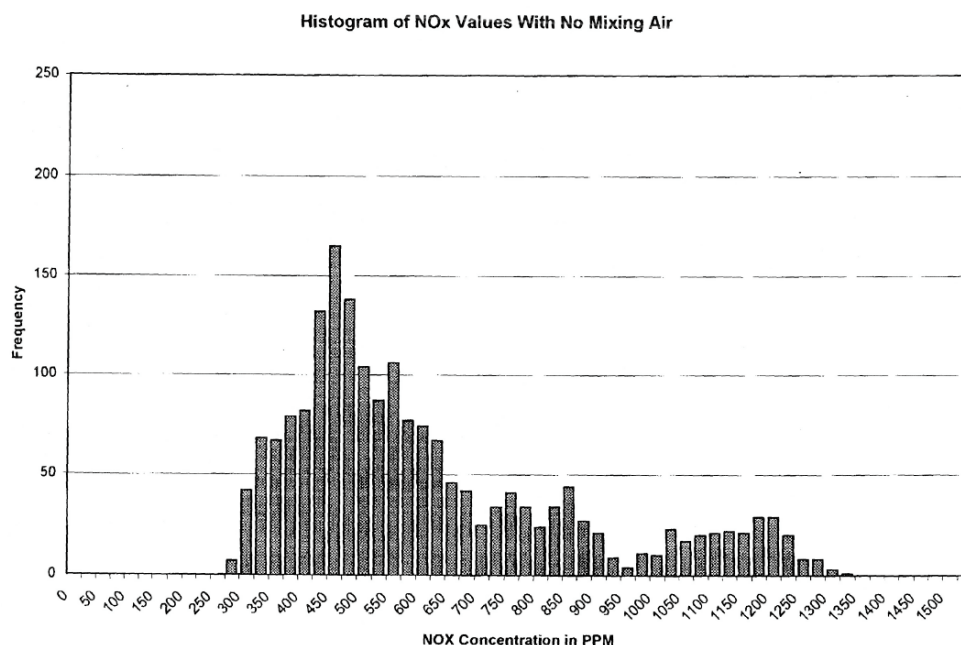
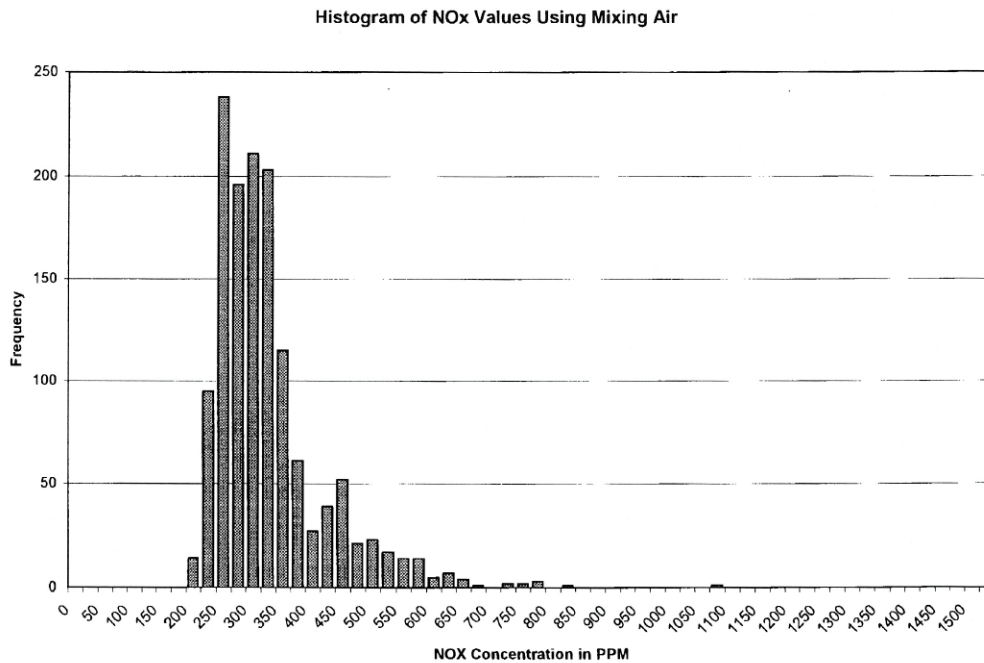


Figure II-17b Frequency of NO_x Values for the Cement Kiln with Mid-Kiln Tire Injection in Figure II-17a (With Mixing Air) ⁴⁰



CemStarSM

Another approach that has been proven effective in reducing NO_x is the patented CemStarSM process, originally developed and sold as a method to increase production of clinker from existing kilns while minimizing capital expenditures.^{43, 44} In the CemStar process, steel or blast furnace slag is introduced as feed material into the kiln. The slag is generally added at the inlet to the rotary kiln (typically after the precalciner or preheater), regardless of kiln type, as shown in Figure II-18. Unlike normal cement materials, which require significant processing to achieve adequate grain size, the slag need only be crushed to 3/4 to 1-1/2 inch pieces. Minimal processing is necessary because the slag has a low melting temperature and its chemical nature is very similar to the desired clinker. Minimal slag processing permits the equipment for the CemStar to be inexpensive and also reduces energy consumption per unit of clinker produced. Moreover, the CemStar process can be implemented on a kiln quickly with minimal impact to facility operations. The equipment needed is mostly material handling equipment as shown on the left in Figure II-18.

Because CemStar provides minerals (such as iron from the steel slag) that are normally provided by other mineral sources such as shale or clay, it is often best to reformulate the kiln feed when implementing CemStar. It may be possible to eliminate the use of mineralizers altogether and reduce the number of raw material components.

The advantages of CemStar approach are many: energy input can be reduced, NO_x emissions (both lbs/hr and lbs/ton of clinker) can be reduced, and kiln capacity can be increased. Since the steel slag more closely resembles the desired kiln product than do the normal raw materials, kilns

with CemStar require less intense firing and allow for a significant reduction of peak burn-zone temperature. The lower burn zone temperature results in less thermal NOx generation. NOx reduction may be expected to be in the range of 20% or more for most kilns. If initial, uncontrolled NOx is high due to thermal NOx, CemStar is likely to provide reductions on the order of 40%-50%. Figures II-19a and II-19b show the results of testing with baseline conditions and CemStar, respectively. A 20% reduction in NOx resulted from CemStar, corresponding with a reduction in average burn-zone temperature of over 200°F.⁴⁵ Kiln capacity is increased because each ton of steel slag added to the kiln results in about a ton of additional production, though the precise amount of additional kiln production is dependent on the mineral characteristics of the local raw material. This capacity increase is the reason that many facility owners may initially choose to use CemStar.

Figure II-18: A Preheater Kiln Adding Steel Slag For CemStar⁴⁶

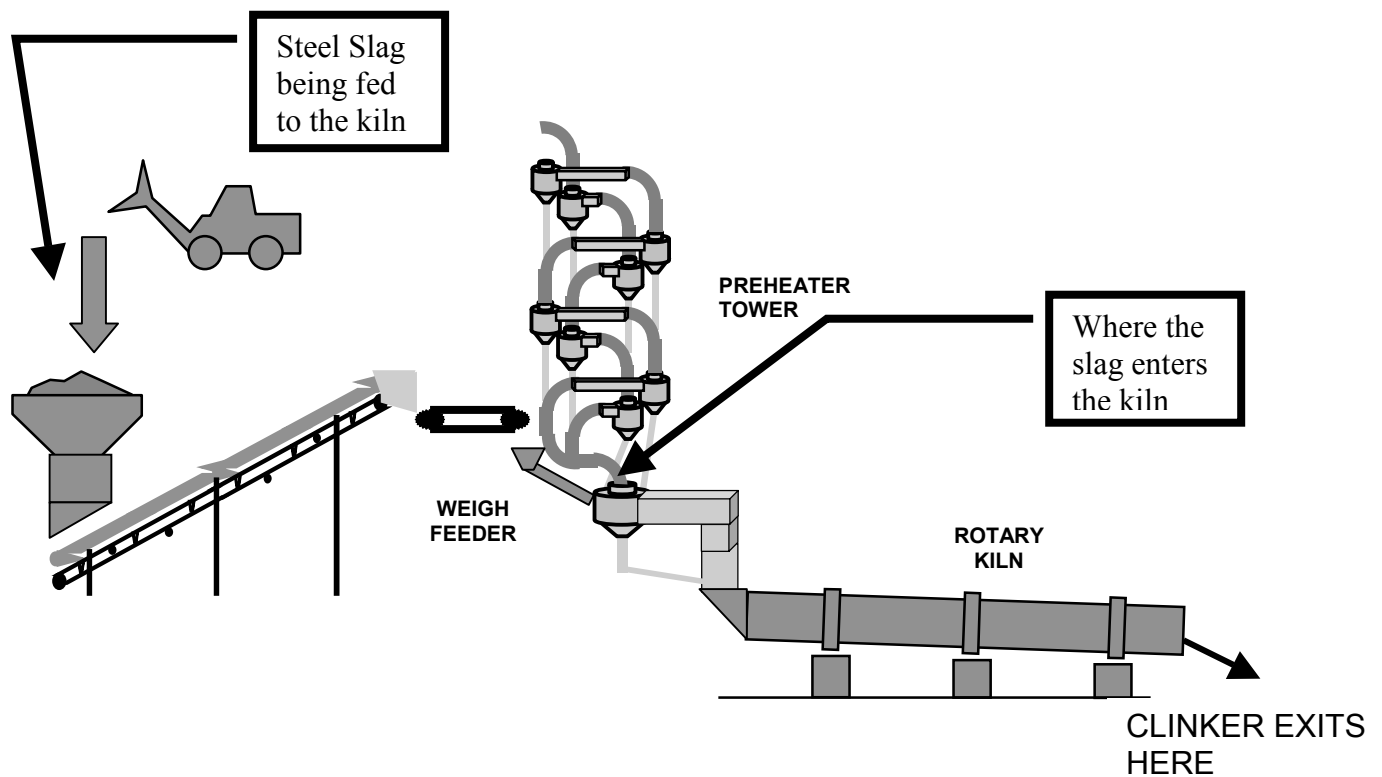


Figure II-19a: Base Case Testing (without CemStar) - NO_x versus Burn-Zone Temperature⁴⁵

Base Case 7/21 to 8/4

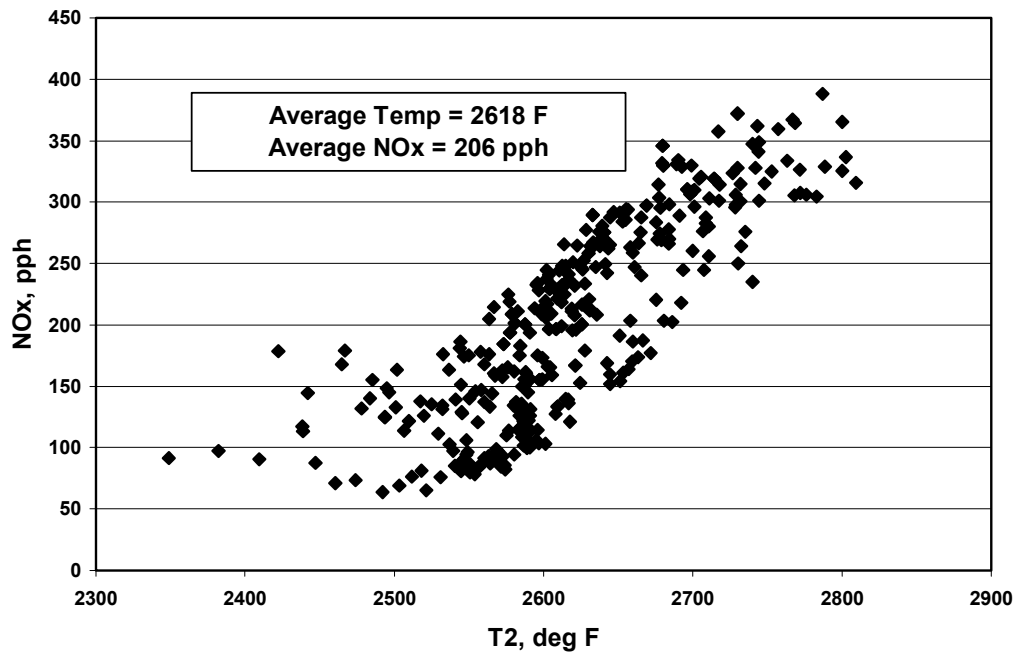
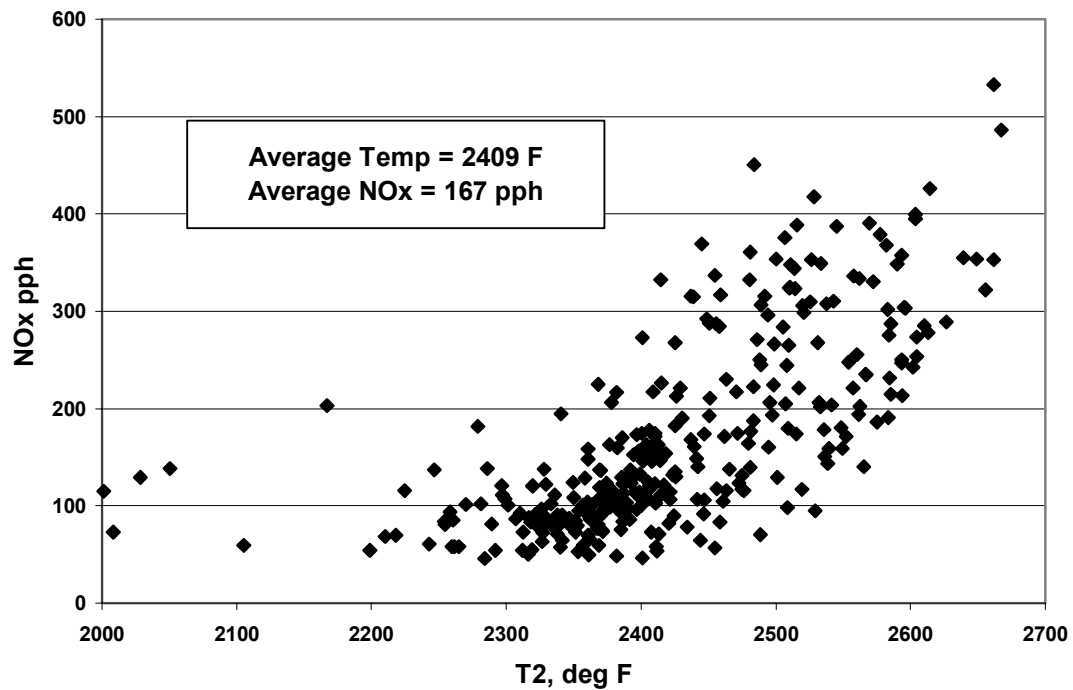


Figure II-19b: CemStar Testing - NO_x versus Burn Zone Temperature⁴⁵

CemStar 8/19 to 9/3



A side benefit to CemStar is reduced CO₂ emissions. CemStar reduces the amount of limestone that must be calcined per ton of clinker. For each ton of slag that replaces an equivalent amount of limestone (on a calcium basis), 0.512 tons less CO₂ will be emitted.

TXI, the developer of CemStar, reports that more than 10 plants are equipped with the technology at this writing. Case Study CK-2 (Chapter IV) discusses one application of CemStar on a long-wet process kiln.

Process Optimization

One final method for reducing NO_x emissions from cement kilns is process optimization. In principal, any effort that reduces the amount of fuel being fired to produce clinker will result in a reduction in NO_x generation. In practice, process optimization often entails the use of advanced computer controls and instrumentation. Many of the primary NO_x control technologies described are implemented along with process optimization to take advantage of their combined effects and to improve overall facility operation. NO_x reductions reported in the previous sections were generally attributed to the changed combustion process (for example, mid-kiln firing). Combined reductions were achieved in case study CK-4, Ash Grove Cement (Chapter IV). Figures II-20a and II-20b, from case study CK-4, show a 55% reduction in average NO_x emissions - from 845 lb/hr to 383 lb/hr - achieved largely by reducing the variability of the process with a computer-automated optimization system. Mid-kiln firing provided additional NO_x reduction, for an overall NO_x emission reduction of 59% from controls.

D.2 Secondary Methods of Controlling NO_x from Cement Kilns

In addition to methods designed to reduce the NO_x that is generated by combustion in the kiln, there are methods that can reduce the NO_x after it is formed. These methods appear to work best on precalciner kilns. It should also be noted that these secondary control measures can be used in addition to methods used to minimize the NO_x generated in the rotary kiln for greater combined NO_x reduction.

Selective Non-Catalytic Reduction (SNCR)

SNCR has been tested in the U.S. on precalciner kilns and is planned for commercial use in other countries.^{9, 47} Experience is limited to only a few units worldwide, but some tests have reported significant reductions. Table II-7 lists commercial installations of urea SNCR on precalciner kilns and the results of some demonstration programs. Effective operation of SNCR requires availability of a section of kiln with the proper temperature and residence time characteristics for good reduction. The specifics of the installation will determine the level of reduction that is possible. It is unlikely that SNCR can be used effectively on many long kilns (wet or dry) because of the need for access to the proper temperature region for injecting urea or ammonia reagent. However on some precalciner kilns the access to the proper temperature zone is good. In one demonstration of urea SNCR on a precalciner kiln, over 80% NO_x reduction was achieved.³⁵ Commercial systems are expected to deliver 25% to about 50% NO_x reduction on some units overseas (see Table II-7). As noted earlier, the specifics of the kiln design determine the level of reduction that may be possible through the use of SNCR.

Figure II-20a: NO_x Emissions at Ash Grove Cement After Process Control (from Case Study CK-4)

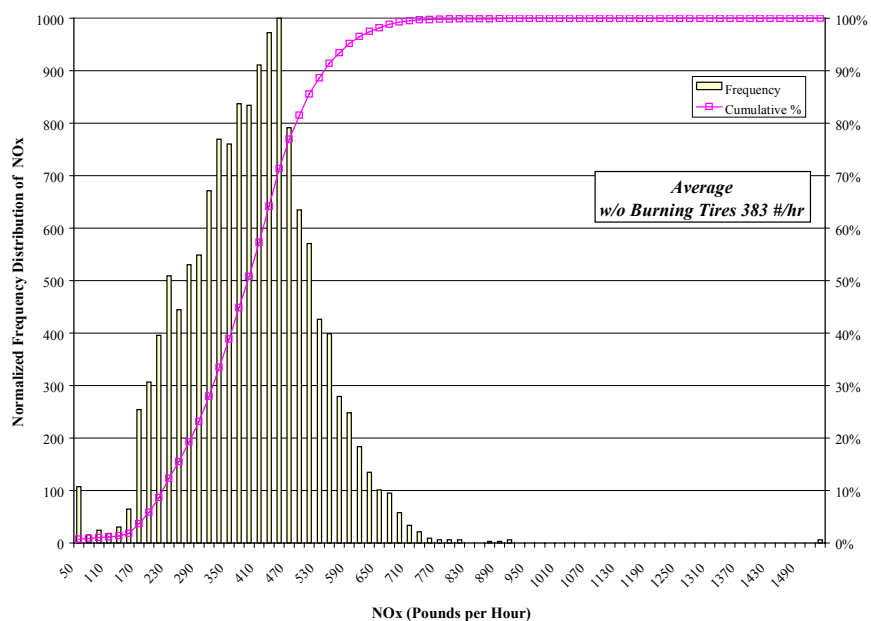
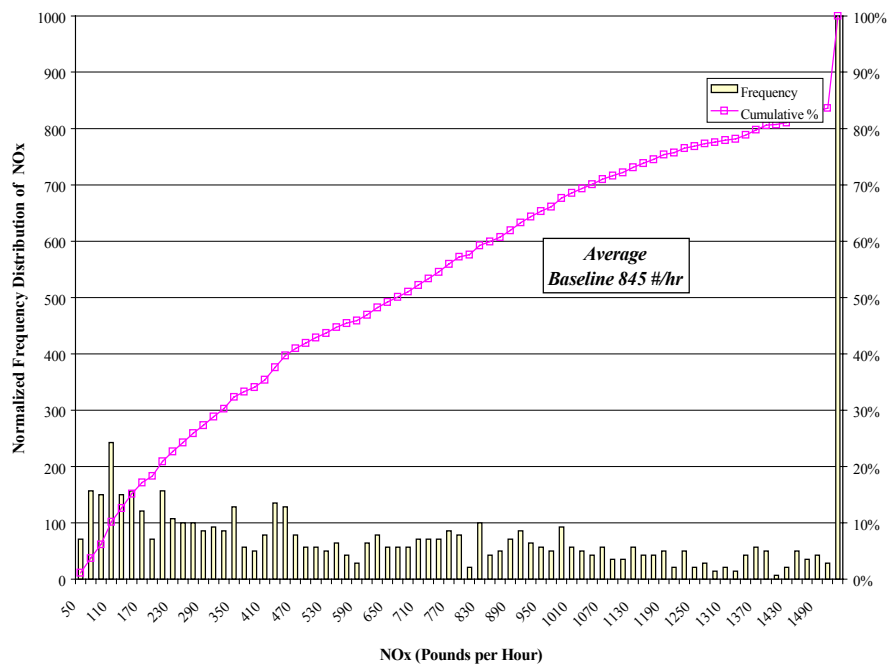


Figure II-20b: NO_x Emissions Histogram at Ash Grove Cement Before Process Control (from Case Study CK-4)



Biosolids Injection (BSI)

BSI is a technology that was developed in the 1990's by the cement industry for NO_x reduction in precalciner and preheater kilns. BSI adds dewatered sewage sludge to the mixing chamber of the calciner, as shown in Figure II-21. The dewatered biosolids provide a source of ammonia, producing an SNCR reaction to reduce NO_x. At a Mitsubishi Cement Kiln in California, BSI provided about 50% reduction in NO_x from about 250 ppm (at 12% oxygen) to 120-125 ppm (at 12% oxygen). BSI has the additional benefit of offering a potential revenue stream because many communities are willing to pay a tipping fee for accepting biosolids. BSI technology may require significant capital equipment expenditures, however. The material handling equipment needed and the moisture in the dewatered biosolids is sufficient to strain the capacity of the fans of many existing facilities. It appears that biosolids injection may be an effective approach for NO_x reduction, but it will depend on the specifics of the kiln.

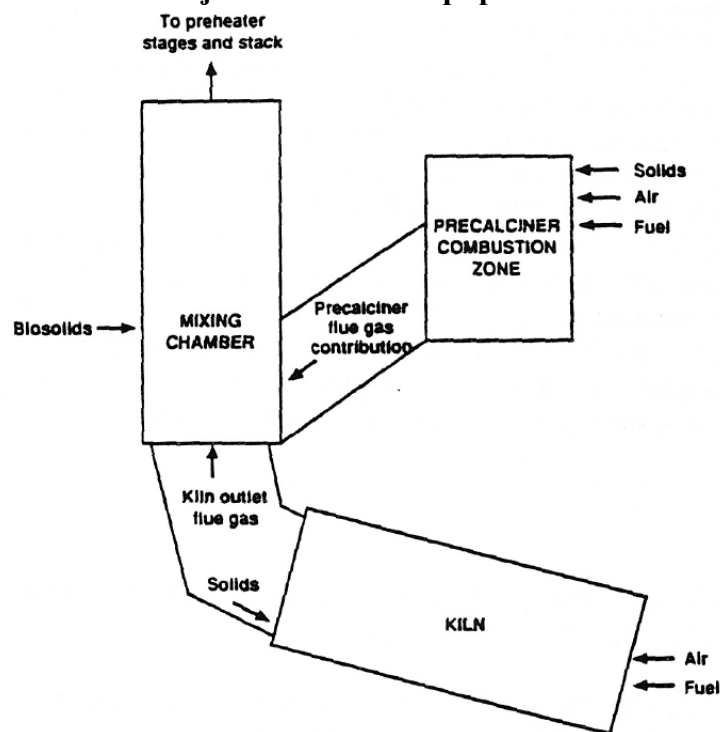
Table II-7: NO_x Reduction Performance of Urea SNCR on Precalciner Cement Kilns⁹

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	NOX BASELINE (ppm, lb/MMBtu)	Reduction (%)	AMMONIA SLIP, (ppm)
Ash Grove Cement Seattle, WA (Demo)	Cement Kiln/ Precalciner	160 tons solids/hr	350-600 lb/hr	>80	< 10
Korean Cement Dong Yang Cement, Korea (Demo)	New Suspension Calciner	na	1.27 lb/MMBtu	45	na
Taiwan Cement Units #3, #5, & #6	Cement Kiln/ Pre-calciner	260	1.29 lb/MMBtu	50	15
		697	1.58 lb/MMBtu	45	15
		658	0.92 lb/MMBtu	25	15
Wulfrath Cement Germany (Demo)	Cement Kiln	140	1000 mg/Nm ³ 500 ppm	90	na

Selective Catalytic Reduction (SCR)

This technology has not been applied to cement kilns in the U.S. Although, in principal, SCR can be used on cement kilns, the SCR reactor must be installed after gas cleaning devices and will require reheating of the gas to achieve the proper temperature for the reaction. A "high-dust" SCR installation, used for most boilers equipped with SCR, may not be possible because of the high calcium content of the dust in cement kilns, which may contribute to deposits that can rapidly reduce catalyst activity. Therefore, this technology is unlikely to be used in the near future to achieve NO_x reduction from existing cement kiln facilities. This technology would more likely be used on new cement kiln facilities rather than existing facilities. In fact, Reference 11 shows low-temperature SCRs on calciner kilns installed in Pittsburgh, CA in 1996. Experience at these calciner kilns may be useful for cement industry applications.

Figure II-21: Biosolids Injection Process Equipment on a Precalciner Kiln ⁴⁸



D.3 Combination of Technologies

It is not uncommon to combine combustion technologies with post-combustion technologies for other source types, and this could be done for cement kilns in some cases. It is also possible to combine multiple combustion technologies on cement kilns. For example, California Portland Cement, in Case Study CK-1, combines indirect firing and mid-kiln firing to reduce NO_x by a combined amount approaching 50%. It is also reasonable to expect that CemStar might be combined with a combustion technology such as mid-kiln firing to provide combined benefits. The exact amount of reduction will depend upon the regulatory requirements and technical limitations. In some cases the NO_x reductions may not be additive.

E. Summary

In this chapter the various commercially available NO_x reduction technologies for industrial boilers, gas turbines, IC engines, and cement kilns were explored. In addition, several emerging technologies that have significant near-term commercial potential were discussed. Any of these technologies may play an increasing role in reducing NO_x emissions from existing sources. In the next chapter the cost effectiveness of those technologies with significant commercial experience will be evaluated. Finally in Chapter IV, case studies will be presented of actual projects where these technologies have been employed. These case studies are the key feature of this report in that they provide "real world" technical and cost input to the calculations of cost effectiveness in Chapter III.

F. References

- ¹ Marx, P. and Barton, C. "Combustion Tempering Demonstration on a Cyclone Unit for NO_x Control." EPRI/DOE/EPA Combined Utility Air Pollution Control Symposium. Washington, DC: August 25-29, 1997.
- ² U.S. Environmental Protection Agency. Alternative Control Techniques Document - NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers. EPA-453/R-94-022, March 1994.
- ³ National Council for Air and Stream Improvement. A Review of NO_x Emission Control Strategies for Industrial Boilers, Kraft Recovery Furnaces and Lime Kilns. Comments submitted in response to EPA's SIP call., 1999
- ⁴ Acurex Environmental Corporation. Fuel Oil Nitrogen Effect on NO_x Emissions and Controlled Levels. Prepared for Northeast States for Coordinated Air Use Management. April 19, 1994
- ⁵ Conti, A.V. and Hersh, S. "Emissions Reductions and Operations Benefits Derived from Low Cost Combustion Hardware Modifications." ASME/EPRI International Joint Power Generation Conference and Exposition. Houston, TX: October 14-16, 1996.
- ⁶ Pickering, R. "Developing Flexible Least-Cost Plans for NO_x Compliance: PSNH's Experiences in Implementing SCR and SNCR Technology." New NO_x Regulations and Power Generation in Competitive Markets. Washington, D.C.: November 3-5, 1999.
- ⁷ Colannino, J. "NO_x Reduction Technologies for Boilers", Council of Industrial Boiler Owners' Eighth Annual NO_x Control Conference. Philadelphia, PA: March 7-8, 1995.
- ⁸ NESCAUM-MARAMA. Status Report on NO_x: Control Strategies and Cost Effectiveness for Utility Boilers. Boston, MA: June, 1998.
- ⁹ Fuel Tech NO_xOUT Experience List. March, 1999, Naperville, Illinois
- ¹⁰ Institute of Clean Air Companies. White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions., Washington, DC, May, 1997.
- ¹¹ Shell DeNO_x System Reference List. Provided to the author by KTI. Concord, CA: April, 1998.
- ¹² Institute of Clean Air Companies. White Paper on Selective Catalytic Reduction (SCR) Control of NO_x Emissions. Washington, DC, November, 1997.
- ¹³ Pritchard, S., Hellard, D. and Cochran, J. "Catalyst Design Experience for 640 MW Cyclone Boiler Fired with 100% PRB Fuel." EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The MEGA Symposium. Atlanta, GA: August 16-20, 1999.
- ¹⁴ Figure provided to the author by Kat Treff of Siemens Corp. Washington, D.C.: June, 1997.
- ¹⁵ Gomez, A.F., Huhmann, A.L., Schrecengost, R.A., Pratapas, J.M., and Johnson, R.A. "Cost Effective NO_x Reduction with Amine Enhanced Fuel-lean Gas Reburn At Public Service Electric & Gas Mercer Station." ICAC Forum 1998. Raleigh-Durham, NC: March, 1998.
- ¹⁶ Sommerlad, R.E., Pratapas, J.M, and Chan, I. "Gas-Based NO_x Control Technologies, An Update on Development and Commercialization." CIBO Ninth Annual NO_x Control Conference. Hartford, CT: March 11-12, 1996.

-
- ¹⁷ Anderson, Skelley, Goren, and Cavello. "A Low Temperature Oxidation System for the Control of NO_x Emissions Using Ozone Injection." ICAC Forum 1998. Durham, NC: March, 1998.
- ¹⁸ Zero Emission Technology. "Electro-Catalytic Oxidation Technical Overview." Personal Communication, June 18, 1999.
- ¹⁹ U.S. Environmental Protection Agency. "EPA Alternative Control Techniques Document - - NO_x Emissions from Stationary Gas Turbines." EPA-453/R-93-007, January, 1993.
- ²⁰ Chalfin, J. and Schorr, M. "NO_x Control Approaching Zero for Gas Turbines - Is It Worth The Price?" Power Gen 1998. Orlando, FL: December 10, 1998.
- ²¹ Rawlins, D.C. "SoLoNO_x Combustion System Update." Solar Turbines Turbomachinery Technology Seminar. TTS082/395, 1995.
- ²² Leslie Witherspoon of Solar Turbines. Letter to the author. May 11, 1999.
- ²³ Catalytic Combustion Systems, "XONON It works at 3 ppm." December 1, 1998.
- ²⁴ Smith, K.O. "Advanced Combustion Systems." Solar Turbines Turbomachinery Technology Seminar. TTS120/398/2M
- ²⁵ Mike Gregory of Peerless Manufacturing Company. Letter to the author. November 16, 1999.
- ²⁶ Krishnan Ramamurthy, Pennsylvania Department of Environmental Protection. Comments on the report, February 13, 2000.
- ²⁷ Gas Turbine World, "Low-temperature SCR Expedites Plant Retrofits for NO_x Reduction," July/August, 1997.
- ²⁸ Goal Line Technologies. Presentation to Northeast States for Coordinated Air Use Management Stationary Source Committee, Northampton, Mass, February 10, 1999.
- ²⁹ Cutshaw, T.R., Reyes, B.E. and Wagner, G.J. "Development of Ultra-Low Emission Controls for Gas Turbines." ICAC Forum 2000. Roslyn, VA: March 23-24, 2000.
- ³⁰ State of California Air Resources Board. CAPCOA/ARB Proposed Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Internal Combustion Engines (DRAFT). Sacramento, Ca, December, 1997.
- ³¹ Coerr Environmental Corporation and Radian International, LLC. "Technical Issues Related to the Potential Use of Selective Catalytic Reduction (SCR) to Reduce NO_x Emissions from Natural Gas-Fired Lean Burn Engines." Prepared for the Gas Research Institute, November 9, 1998.
- ³² Johnson Matthey. "Mobil Reduces NO_x Emissions by 82% and 92% from Diesel and Natural Gas Test Engines Using Johnson Matthey Urea SCR (Selective Catalytic Reduction) System." Press release. December 6, 1999.
- ³³ Clean Diesel Technologies, Inc. Product Bulletin: "NO_xOUT SCR NO_x Control Technology & The ARIS 2000 Injection System," 1999
- ³⁴ Garth Hawkins, P.E. of the Portland Cement Association. Letter to the author. May 10, 1999.
- ³⁵ Sun, W.H., Bisnett, M.J., et al. "Reduction of NO_x Emissions from Cement Kiln/Calcliner through the Use of the NO_xOUT Process." International Specialty Conference on Waste Combustion in

Boilers and Industrial Furnaces. Air and Waste Management Association. Kansas City, MO: April 21, 1994.

³⁶ Portland Cement Association. U.S. and Canadian Portland Cement Industry: Plant Information Summary, December 31, 1997.

³⁷ U.S. Environmental Protection Agency. "Alternative Control Techniques Document -- NOx Emissions from Cement Manufacturing." EPA453/R-94-004, March, 1994.

³⁸ Young, G. L. and von Seebach, M. "NOx Variability Emission and Control from Portland Cement Kilns." Proceedings of the 34th International Cement Seminar, December 6-9, 1998

³⁹ Portland Cement Association. "Report on NOx Formation and Variability in Portland Cement Kiln Systems Potential Control Techniques and Their Feasibility and Cost Effectiveness." PCA R&D Serial No. 2227, December, 1998.

⁴⁰ Eric Hansen of Ash Grove Cement. Letter to author. January 17, 2000.

⁴¹ Schrama, H., Blumenthal, M., and Weatherhead, E. C. "A Survey of Tire Burning Technology for the Cement Industry." IEEE Cement Industry Technical Conference. San Juan, Puerto Rico: June 4-9, 1995.

⁴² Stillwater, M.A. and Wahlquist, C.J. "Building a Successful Tire Derived Fuel Program." Proceedings of the 34th International Cement Seminar. December 6-9, 1998, Salt Lake City, UT.

⁴³ Young, R.D. "Method and Apparatus for Using Steel Slag in Cement Clinker Production." U.S. Patent No. 5,421,880. Issued June 6, 1995.

⁴⁴ Young, R.D. "Method and Apparatus for Using Blast-Furnace Slag in Cement Clinker Production." U.S. Patent No. 5,494,515. Issued February 27, 1996.

⁴⁵ Greg Mayes of Texas Industries, Inc. Letter to author. February, 2000.

⁴⁶ Texas Industries, Inc. Marketing Presentation, June 9, 1999.

⁴⁷ Steuch, H.E., Hille, J., Sun, W.H., Bisnett, M.J, and Kirk, D.W. "Reduction of NOx Emissions from a Dry Process Preheater Kiln with Calcliner Through the Use of the NOxOUT Process." Portland Cement Association Meeting of the General Technical Committee. Seattle, WA: September 18-21, 1994.

⁴⁸ Biggs, H.O. "BioSolids Injection Technology: an Innovation in Cement Kiln NOx Control." Proceedings of the 31st International Cement Seminar. TP 881 .15, 1995.

III. Technology Costs

The decision to use a particular control technology on a facility is largely an economic one, once the technically feasible approaches and regulatory requirements have been identified. Operators of facilities will always choose the approach that meets their needs for control while minimizing the expected cost of control. Therefore, an understanding of cost effectiveness of different approaches for NO_x control is essential to understanding how the technologies might be deployed. This chapter addresses the economics of applying various NO_x control technologies to the sources of interest.

This chapter builds upon the information in Chapter II and estimates the costs of applying established NO_x reduction technologies on existing facilities. The chapter describes the methods used to estimate lifetime costs of implementing NO_x controls, and presents the results of the cost effectiveness analysis for industrial boilers, gas turbines, internal combustion engines, and cement kilns.

A. Costs of Control

The analyses performed for this report and the results presented are intended to be representative of many situations that are likely to be encountered by potential users of NO_x reduction technology, but do not include the entire universe of applications that may be encountered. The situations addressed in this report are *typical*, and though there will be situations that are not addressed in this document, it is expected that these will be only a small fraction of applications. The analyses of this section assume that the technology selected is technically appropriate for its application. Due to the wide range of applications within some source categories, it is possible that, for any particular application, some technologies identified in this report may not be appropriate, or, for a particular actual situation, the technology might be uneconomical due to special circumstances. In order to estimate the cost effectiveness of controlling NO_x from a source category with a specific technology, it is necessary to assume that the technology selected is feasible.

Cost analysis was only performed for technologies where commercial installations exist and there was enough data available to estimate cost effectiveness with some reliability. Therefore, technologies that are identified in Chapter II as "emerging" were not analyzed for cost because there is not enough data available to produce reliable estimates for these technologies at this time.

A.1 Cost Data

Industrial users of NO_x reduction technology are generally less likely to publish articles or technical papers on their experience with NO_x control technology than are electricity generating utilities, leading to much less publicly available data on cost and performance of NO_x reduction technology from industrial users than from electric utility boilers. Although actual data from case studies and technology users was relied on heavily, in some cases it was necessary to rely on additional sources. In this respect, the analysis in this report is slightly different than that in Reference ¹, which relied almost exclusively on information from case studies and other user-

provided information. In this study it was necessary to assemble information from technology suppliers and users, and from documents published by EPA, state, and local regulatory agencies.

Information gathered in case studies was the primary basis for estimating costs, when this data was available. When case study information was not available, cost information from other sources was used. The case study information on capital cost generally corresponded well with the cost information from other sources. Additionally, the case studies provided valuable information about what these users actually budgeted for fixed Operating and Maintenance (O&M) costs.

In contrast to capital cost data, variable operating cost information (reagent costs, incremental fuel cost, etc.) can generally be estimated with good accuracy using existing data and engineering calculations of reagent consumption, catalyst consumption, fuel use, etc. This method was used in this report.

B. General Methodology

In this chapter, two general approaches will be used to estimate cost effectiveness. These two approaches will be shown to be consistent for assessing cost-effectiveness of different control approaches. The results of calculations presented later in the chapter are averages of the approaches. The first method projects a detailed pro forma cash flow over the project life. The second method makes an annualized base-year estimate (with 1999 as the base year). The base-year estimate method is, of course, much simpler to use. Combined use of both methods incorporates the following benefits: 1) the pro forma method is more flexible, it provides a richer amount of information, and can be used to address a much wider range of economic assumptions; 2) the pro-forma method shows the cost of controlling NO_x with and without the effect of taxes, which can be a significant factor; and 3) the consistency of the two methods in determining cost-effectiveness of controls on a before-tax basis provides greater confidence in both methods. Costs will be estimated using a “Constant Dollar” approach. The base year for the constant dollar approach was chosen to be 1999.

In order to perform the pro-forma analysis, it is first necessary to make a reasonable estimate of inflation to predict escalation of costs. Inflation is difficult to predict with certainty, but its effects on long-term projects are so significant that it must be considered.^{vi} Despite the uncertainty regarding the actual future rate of inflation, it is possible to estimate current or anticipated future inflation. The nominal yield on 3-month treasuries averaged about 2.1% above the rate of inflation from 1976 until 1985, and during this period the yield on 3-month treasuries ranged from 3.33% to 8.11%.² At the time of this writing, the yield on 3-month treasuries is about 4.75%.³ This implies an *expected* near-term rate of inflation of about 2.6%. Although inflation over the life of a project is likely to differ from the current near-term inflation rate, it is impossible to predict how it will differ.

^{vi} For example, an average inflation rate of 2.6% will cause prices in ten years to *appear* 30% higher. An annual inflation rate of 5% will cause prices in ten years to appear over 60% higher. The inflation rate will vary over time, which makes estimating inflation difficult. Annual inflation rate averaged 1.3% from 1953 to 1965, averaged 9.2% from 1973 to 1981, and averaged 3.6% from 1982 to 1995.² Inflation since 1995 has been extremely low, but it is uncertain if this trend will continue in the coming years.

Moreover, inflation in the early years of the project has the greatest effect on the overall project economics. For the cost estimates in this report, a near-term inflation rate of 2.6% is assumed for the pro-forma analysis.

It is important to note that if costs are estimated for the purpose of capital budgeting for a specific year in the near term (within the next five years, for example), a "Current Dollar" approach would be used to estimate cost and the nominal dollars required in the budget for a particular year.

B.1 Components of Cost

The costs of employing a technology include the capital cost associated with placing the technology in service, lost production due to down time while the technology is installed, and the fixed and variable operating and maintenance costs associated with using the technology.

The capital cost of a project is determined by the cost of the equipment, materials, shipping, labor and other costs associated with placing the system in service. It is often necessary to fund the capital purchase with funds "borrowed" from lenders and shareholders, who each require a fair return on the money they provide. These two considerations determine the financing costs. Moreover, taxes (property and income), insurance, and depreciation all impact the cash-flow effects of employing a piece of equipment. It is not possible to explore every possible mode of financing in this report, but reasonable assumptions can be made (Table III-1). These assumptions were used to determine the Weighted Average Cost of Capital (WACC). For more information about WACC, see Reference ⁴.

The values in Table III-1 reflect an anticipated average for most U.S. companies likely to install NOx reduction equipment (utilities, large corporations, and medium sized companies). In general, electric utility and other projects financed by large, well-capitalized companies will tend to have lower debt costs, higher proportion financed with debt (lower proportion financed with equity), and longer project economic life than the facilities examined in this report.

Other studies^{1,5,6,7,17} have used a simple payment equation for addressing the costs of capital. As shown later in this chapter, this normally provides a sufficiently accurate estimate for cost effectiveness in terms of \$/ton of NOx reduced. However, some previous studies have received critical comments regarding this treatment of costs and financing, calling such treatment too simplistic.¹ To address these concerns, the base year approach was combined with the pro forma method. The "base year" approach is consistent with the methods in EPA's Alternative Control Techniques (ACT) documents.^{5,6,7,17} Whether using the simpler approach or the more robust approach, the results in this study were shown to be reasonably close, typically well within 10%, unless the reported values were small. For smaller values, (less than \$500/ton of NOx removed), the results of the two analyses sometimes differed by as much as \$100/ton, but usually by much less. The results of cost-effectiveness calculations reported in the tables and figures in this chapter are the average of both approaches, unless noted otherwise.

Table III-1: Assumptions for Pro Forma Economic Analysis	
Cost of Debt	7.5%
Fraction of Debt Financing	40%
Cost of Equity	15%
Fraction of Equity Financing	60%
Project Economic Life	15 years
Depreciation for Tax Purposes	MACRS ^{vii}
MACRS Class	10 year
Property Taxes (\$/1,000)	\$15 ^{viiiix}
Insurance	Negligible ^{viii}
Income Tax Rate	35%
Inflation rate	2.6%

Cost of material and labor used over the life of the program will vary as the costs of those items increase (or sometimes decrease). In most cases they will increase. For the sake of this analysis, it is assumed that all material and labor that make up annual expenditures for operation and maintenance of the system will increase in cost with the general level of inflation. Of course, in reality some items will increase in cost more and some less than the rate of inflation. But, for this analysis the simplifying assumption is that the general rate of inflation will be a reasonable estimate for the increase in cost for all items.

The capital costs for various retrofit projects included in this report were determined from reported costs in published references and as estimated from information in the case studies of Chapter IV. Cost analysis is only performed for those technologies where there is sufficient experience such that reliable data is available to estimate cost. Therefore, there is no cost analysis for emerging technologies in this report.

The operating and maintenance costs of the technology are determined by the cost of additional materials, (fuel, reagent, catalyst, replacement parts, etc.) and labor associated with owning and operating the technology. Published references (cited where appropriate later in this chapter) and case study information are used to determine the value for each of the components of operating and maintenance costs. Table III-2 lists assumed cost of certain consumables that will impact operating cost.

^{vii} MACRS is an accelerated method of depreciation accepted by the IRS for tax purposes.

^{viii}

^{ix} Property taxes are determined by local law and, as discussed in Reference 8, frequently are not applied to capital improvements associated with air pollution reduction. They are included in this analysis for conservatism. In Reference 8, increased insurance costs were shown to be negligible for this type of analysis.

Table III-2: Cost of Operating Consumables	
Coal	\$1.50 /MMBTU
Natural Gas	\$2.25 /MMBTU
Distillate Fuel Oil	\$5.00/MMBTU
Ammonia (aqueous)	\$360 /ton (active agent)
Urea (50% by weight aqueous solution)	\$0.95/gallon
SCR Catalyst (except metal washcoat)	\$10,000-\$14,000/m ³
It is recognized that the cost of these operating consumables will vary from time to time and from location to location; however, it is not possible to explore every possible situation in this report. These values are suggested to be representative of a large number of facilities in the U.S.	

B.2 Cost Analysis

The current dollar cash flow impacts of the NO_x reduction technology, including operating consumables, maintenance, property taxes and effects of depreciation, are projected in a Microsoft Excel Worksheet. These are adjusted for tax effects because it is assumed that the business has earnings that are subject to income taxes and the company earnings and taxes payable will be impacted by the project. To this is added an annualized capital charge that is determined to be equal to a payment at the company's Weighted Average Cost of Capital (WACC) over the project lifetime. As is normally done in project analysis, the cash flows are estimated as if the hardware and installation was an all-cash acquisition. The cost of financing is captured in the annualized capital charge (the WACC or discount rate). However, in the worksheets (see Appendix A) that were generated the actual cash flows inclusive of financing effects were shown as well, based on the financing assumptions that were made. The financing cash flow projections (specifically, debt interest and principal) are shown for information purposes only, and these numbers do not contribute to the end result of the analysis (the cost-effectiveness in \$/ton of NO_x removed). The financing cash flows projected in future years do not figure into the cost-effectiveness analysis since, consistent with common project analysis methods, the purchase is treated as an all-cash transaction with financing at the WACC. An annual capital charge, determined by the total capital cost and WACC, is applied each year which does figure into the \$/ton cost estimate. Future operating and maintenance cash flows are discounted at the rate of inflation, assumed to be 2.6%/year, to produce constant dollar values.

Because the analyses of References 1, 5, 6, 7, 17 show results on a before tax basis, the Excel worksheet (Appendix A) also shows the results before taxes. *It is notable that the after-tax costs will be less than the before tax costs because for most companies the tax bill will be reduced as a result of reduced before-tax income.* Depreciation, a non-cash expense, has a very large effect on reducing the tax bill. The operating and maintenance expenses are offset somewhat by reduced income taxes. A less significant effect that is incorporated into the analysis is the effect of interest payments in reducing the tax bill. This is why there are two WACC's shown in the spreadsheet. One includes the effect of taxes on effectively reducing debt expense and the resulting annual capital charge, and the other doesn't. The "After Taxes" analysis includes this effect on debt and the "Before Taxes" analysis does not. Because the results of most other studies have been presented on a before-tax

basis, the before-tax results of this study should be used for comparison against the results of other studies. All results presented in this chapter and in other parts of the report are on a before-tax basis. After-tax results can be seen on the sample worksheets in Appendix A. The worksheets show that when the effects of taxes are included, the costs can be much less.

Comments Regarding Net Present Value Analysis

For most capital purchases a Net Present Value (NPV) analysis, which discounts all future cash flows, is generally performed by a company. A traditional NPV analysis was not performed in this study because of uncertainty regarding the appropriate discount rate. WACC is typically used as the discount rate for future cash flows in NPV analysis. However, the proper discount rate for an NPV analysis on NOx reduction technology should be somewhat less than the WACC. This is because the costs of reducing NOx can be predicted with much more certainty than customer payments and other cash flows that have a greater impact on business risk than the cost of controlling NOx. So, while the WACC is appropriate for determining the cost of financing the capital cost of a NOx reduction system (providers of debt or equity capital need to be compensated at a fair rate), WACC is not appropriate for discounting the future cash flows associated with the NOx reduction system. *An NPV analysis using WACC as the discount rate would underestimate the true cost of controlling NOx.* Furthermore, many industrial companies (especially utilities) evaluate these projects on a revenue requirement basis (revenue required to cover all costs, including capital recovery), which is similar to the analysis that was performed in this study. Revenue requirement methods apply a Capital Recovery Factor (CRF) to the initial capital cost to determine an annualized capital recovery cost. This is effectively what was done for this analysis. In the analysis performed in this report, future cash flows were discounted at the rate of inflation. It could be argued that the rate of return determined by long-term treasury bonds would be a better choice for discount rate of future operating costs because it would incorporate the cost of money as well as inflation. But, the inflation rate was assumed because of simplicity and conservatism.

Comparison with the Approach in EPA's Alternative Control Technique (ACT) Documents

As noted earlier, a very simple "base year" (1999) analysis using a CRF calculated in the same manner as in the appropriate EPA ACT document (Refs.5, 6, 7, 17) is shown in the worksheet. This is to ensure that the results are comparable to those of the ACT documents. In nearly all cases the results for \$/ton of NOx (before-tax basis) are within about 10% of the approach of the ACT document when economic assumptions are similar (project life, etc.). A benefit of performing both analyses (simple, as in the ACT document, and more robust as done in this report) is that the ACT results are shown to be reasonably consistent with the results of the more robust approach. Results were almost always within the greater of 10% or \$100/ton of one another and more often much closer.

Cost Effectiveness of Seasonal versus Annual Controls

Ground-level ozone formation is primarily a seasonal concern (May 1 - September 30), and regulations relating to NOx emissions for the purpose of controlling ground-level ozone formation often focus on making reductions over a five-month period when ozone formation is of greatest concern. (It should be noted that a number of states in the Northeast have either adopted or are currently seriously considering year-round controls of NOx emissions for additional benefits towards reductions of acid deposition, improvement in visibility, reductions in fine particle concentrations, and other environmental benefits.) Some technologies can be secured ("turned off") outside of the

ozone season if the reductions provided by that technology are not currently required to comply with ozone regulations. This way the operators of the source will incur less cost than if they operated the NOx reduction technology for the entire year.

SNCR and gas reburn are technologies that lend themselves well for operation in this manner because most of the cost of use is associated with reagent consumption or additional fuel cost. On the other hand, some technologies may only be operated such that they provide continuous reductions year round. Generally, they cannot be turned off. Combustion technologies, such as Low-NOx Burners and Dry Low NOx fall into this category. Although the off-season reductions have many environmental benefits noted above, they do not figure into the economic decision of the operator if the operator is not required under current regulations to make those reductions. Therefore, if the operator installs the technology solely for the purpose of obtaining ozone-season reductions, it is reasonable that only ozone season NOx reductions should be used in the calculation of cost effectiveness, as was done in the recent EPA's cost analysis for the "NOx SIP (State Implementation Plan) Call" action. For this reason, in calculations for cost effectiveness in this chapter, values are shown for both annual reductions and ozone-season reductions for all technologies, even if the technology provides NOx reductions year round. In cases where the technology may not be operated outside of the ozone-season, it is assumed that the variable operating costs (costs associated with urea, ammonia, natural gas, etc.) are zero outside of the ozone season. For SCR, it is assumed that the catalyst continues to be degraded in proportion to the annual operation of the facility, not just when ammonia is being injected for the purpose of NOx reduction.

C. Industrial Boilers

C.1 Cost Effectiveness of Primary Methods of Controlling NOx from Industrial Boilers

Cost effectiveness of primary control methods is driven primarily by the capital cost of the controls, the effectiveness of the controls in reducing NOx, the uncontrolled NOx level, and the capacity factor of the boiler. Since this study is directed primarily at major sources, small commercial boilers that operate intermittently are of less interest than larger, field-erected units used by large industrial users that operate at higher capacity factors. This study evaluates cost effectiveness of various control technologies at three (low, medium, and high) capacity factors of 45%, 65% and 85%, overlapping the range of 33% to 80% considered in Reference 5.

Unfortunately, few of the case studies described in this report provided additional insight to the cost effectiveness of NOx control for industrial boilers using combustion controls. It is therefore necessary to rely heavily on published data. Reference 5 forms the basis for the costs in this analysis, with other references cited when used. The capital costs of controls are from Reference 5, or from the case studies as available, though it is recognized that performance and cost will vary somewhat from one facility to another. The initial baseline level will vary as well, which will significantly impact the cost effectiveness.

Table III-3a shows cost effectiveness on an annual and seasonal basis for installation of Low-NOx Burners to achieve NOx reduction from 0.60 lb/MMBTU to 0.38 lb/MMBTU (a 60% NOx reduction) on a coal fired boiler as a function of capacity factor. Table III-3b shows the results of similar calculations for identical conditions, with NOx reduced to only 0.45 lb/MMBTU (a 25%

reduction). Experience with electric generating units has shown that NO_x levels well below 0.50 lb/MMBTU are typical with LNBs and sometimes NO_x levels approaching 0.30 lb/MMBTU are possible on wall- and tangential-fired units, so assuming an approximate control level in the range of 0.40 lb/MMBTU for industrial boilers is reasonable. Application of low NO_x combustion technology can adversely impact boiler efficiency, but these effects are difficult to predict and generally have a minor impact on cost. Therefore, these effects are ignored for the purpose of this analysis.

As shown in the tables, NO_x reduction is possible on an annual basis for under \$2,000/ton of NO_x removed for all conditions, and under \$1,000/ ton in some cases. For seasonal controls, cost per ton of NO_x reduction is higher by a factor of about two.

The analyses for both tables assume a capital cost of about \$5,000/MMBTU/hr, which is close to the assumed value in Reference 5. In cases where the cost is higher or lower than \$5000/MMBTU/hr, the cost effectiveness is scaled in proportion to the capital cost. For example, if the capital cost is actually \$6,000/MMBTU/hr, the cost effectiveness (in \$/ton) is increased proportionately by 20%. Similarly, if capital cost is only \$2,500/MMBTU/hr, then the cost effectiveness (in \$/ton) should be reduced by half.

Table III-3a: Cost Effectiveness for NO_x Reduction with LNB on a 350 MMBTU/hr Coal-Fired Boiler with Capital Cost of \$5,000/MMBTU/hr (36% NO_x Reduction From 0.60 lb/MMBTU)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$3,308	\$2,290	\$1,751
Annual	\$1,378	\$954	\$730

Table III-3b: Cost Effectiveness for NO_x Reduction with LNB on a 350 MMBTU/hr Coal-Fired Boiler with Capital Cost of \$5,000/MMBTU/hr (25% NO_x Reduction From 0.60 lb/MMBTU)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$4,763	\$3,298	\$2,522
Annual	\$1,985	\$1,374	\$1,051

Table III-4a shows the cost effectiveness of a gas-fired Low -NO_x Burner retrofit capable of 50% reduction from 0.20 lb/MMBTU with a capital cost of ~\$5,000/MMBTU/hr for a field-erected facility. Note that for the seasonal analysis, credit is taken only for those reductions during the 5-month ozone season, even though NO_x reductions occur year round. In this case annual NO_x reductions are possible for under \$2,000/ton, while seasonal control is more expensive.

Other, less expensive approaches for reducing NO_x may be possible, such as “Burners Out of Service,” simple modification of existing hardware, or modification of swirlers, fuel guns, etc. An analysis was performed for modifications that would cost only \$300/MMBTU/hr but achieve only a small NO_x reduction of 25%. As shown in Table III-4b, modification of existing hardware or

otherwise less expensive equipment may reduce NO_x, making NO_x reductions possible for under \$1,000/ton under all circumstances evaluated. Even if NO_x reductions were much less (say, only 10%), NO_x reductions would still be well below \$1,000/ton, annually and under \$2,000/ton, seasonally.

As noted in Chapter II Section A.1, fuel nitrogen content of No. 6 fuel oil can vary from 0.1 to 0.6%, which will significantly impact the effectiveness of Low-NO_x Burners when firing residual fuel oil. In Case Study BLR-2 (Chapter IV), a NO_x reduction of 10% was achieved with a total capital cost of only \$30,000 through simple burner modifications. These boilers had a fairly high fuel nitrogen level of 0.46%, limiting the ability to lower NO_x with LNBs. Table III-5 shows the results of cost calculations for this application.

Table III-4a: Cost Effectiveness for NO_x Reduction with LNB on One Gas-Fired 350 MMBTU/hr Boiler

50% NO_x reduction from 0.20 lb/MMBTU and Capital Cost of \$5,000/MMBTU/hr

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$7,145	\$4,946	\$3,783
Annual	\$2,977	\$2,061	\$1,576

Table III-4b: Cost Effectiveness for NO_x Reduction Through Minor Modifications on One 350 MMBTU/hr Boiler

25% NO_x reduction from 0.20 lb/MMBTU and Capital Cost of \$300/MMBTU/hr

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$857	\$594	\$454
Annual	\$357	\$247	\$189

Table III-5: Cost Effectiveness for Burner Modification on Two Oil-Fired 680 MMBTU/hr Boilers

10% NO_x reduction from 0.43 lb/MMBTU and Capital Cost of \$30,000, or \$22/MMBTU/hr (Case Study BLR-2)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$72	\$50	\$38
Annual	\$30	\$21	\$16

C.2 Cost Effectiveness of Secondary Methods of Controlling NO_x from Industrial Boilers

Selective Non-Catalytic Reduction (SNCR)

The costs of SNCR for an industrial boiler will depend, in part, on boiler type, fuel, reagent, and operating mode. Some boilers, because of their size and higher furnace temperatures, lend themselves better to urea use than to ammonia use. Urea's temperature window is slightly higher and broader than that of ammonia, and urea is easier to distribute in large furnaces. The cost of ammonia systems is sometimes greater due to the more sophisticated injection systems that are required.¹ For the sake of conservatism, the analysis in this program will be for urea-based systems. In some cases this will result in a slightly higher cost per ton of NO_x removed than for an ammonia system. However, this analysis does not include the additional cost of safety precautions that may be necessary when using ammonia reagent.

For boilers of about 250 MMBTU/hr or more, capital cost is expected to vary from about \$500,000 to \$1,000,000 for urea SNCR technology. Table III-6 shows the cost of various commercial urea SNCR systems. For ammonia SNCR, the capital cost may be less for fluidized-bed or bubbling-bed boilers. However, this equipment cost advantage may be offset by safety provisions sometimes necessary when using ammonia. Such safety provisions are determined by local government authorities and can vary widely from one location to another.

Minergy Corporation, in Neenah, Wisconsin (Case Study BLR-1, Chapter IV), reported a capital cost of \$500,000 to \$750,000 for its 350 MMBTU/hr facility. Using an average cost of \$625,000 and adding \$150,000 for the cost of installation, a total cost of \$775,000 was used for this analysis. For a 15-year project life, 5-month ozone season control, and a capacity factor of 65%, the cost of NO_x reduction over the project life is estimated to be about \$2,450/ton of NO_x removed. For annual control the cost effectiveness would be about \$1470/ton of NO_x removed. Table III-7 shows the effect of capacity factor on cost effectiveness of NO_x reductions

Table III-6: Reported Cost of Urea SNCR for Wood-Fired Power Boilers ⁸					
Size, MMBTU/hr	Boiler Type	Capital Cost	Estimated Annual Operating Cost	Baseline NO _x	NO _x Reduction
900	Grate-Fired Biomass	\$1.1 M	\$230 K	235 ppm	50%
475	Combustion Engineering Stoker	\$700K	\$54 K	0.47 lb/MMBTU	60%
300	Riley Stoker	\$600K	\$40K	0.25 lb/MMBTU	30-50%
245	Front-Fired Fiber Waste	\$390K	\$58 K	370 ppm	50%
Capital cost shown includes equipment, engineering, and commissioning, but not installation. Installation typically adds about 20% to 30% to the cost.					

Table III-7: Cost Effectiveness for SNCR NO_x Reduction on a 350 MMBTU/hr Boiler

35% NO_x reduction from 0.45 lb/MMBTU (Case Study BLR-1)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$3,303	\$2,518	\$2,101
Annual	\$1,814	\$1,470	\$1,300

Selective Catalytic Reduction (SCR)

There have been relatively few SCR systems installed in the U.S. on industrial boilers or process heaters firing fuels other than natural gas or refinery gas. Since there are currently no coal-fired industrial boilers in the U.S. that have been retrofitted with SCR, it is necessary to estimate costs from what is known about electric generating SCR retrofits on coal-fired boilers. Reference 1 demonstrated that there is a pronounced economy of scale for SCR on coal-fired boilers, which makes SCR more expensive per unit of boiler heat input (or facility output) on a small boiler than a large one. However, on sufficiently small applications, the SCR reactor and controls can be shop fabricated in a modular form. This may reduce the amount of field erection and engineering resulting in lower costs. Operating costs (ammonia and catalyst) can generally be estimated with a high level of certainty once the boiler characteristics are known.

Since SCR application to a coal-fired boiler is most likely to provide cost-effective NO_x reductions, an example of a coal-fired application is used to estimate costs. As noted above, since there are no coal-fired industrial boilers in the U.S. that have been retrofitted with SCR, it is necessary to project costs from what is known about electric utility SCR retrofits on coal-fired boilers. Costs are calculated for NO_x reduction on a 350 MMBTU/hr boiler at an estimated capital cost range of \$10,000/MMBTU/hr to \$15,000/MMBTU/hr. This range is reasonable if cost experience with utility boilers is extrapolated to smaller industrial boilers, with \$10,000/MMBTU/hr near the high end of the capital cost of a utility boiler of about 100 MW size (1,000 MMBTU/hr). Given the greater economies of scale for utility boilers compared to industrial boilers, we assume that SCR capital cost for an industrial boiler will be higher on a \$/MMBTU/hr basis than for a utility boiler.

The SCR applications for an industrial boiler in the U.S. are on relatively clean applications. Even the SCR in Case Study BLR-4 (Chapter IV), a 57 MMBTU/hr wood-fired facility at Sauder Woodworking, is downstream of a hot-side ESP (electrostatic precipitator) that removes most dust in the exhaust stream. In this case study, the cost of the catalyst, catalyst reactor, ammonia flow control, ammonia injection grid, and engineering was about \$450,000. Additional costs include installation labor and materials, the anhydrous ammonia storage tank, and startup.⁹ Adding 25% for the hardware and labor to install the SCR and to provide an ammonia storage tank yields a cost of under \$9,500/MMBTU/hr for this 57 MMBTU/hr application. SCR capital costs tend to exhibit economies of scale and a 350 MMBTU/hr boiler firing relatively clean fuel would likely cost well below \$9,500/MMBTU/hr, probably around \$5,000-\$6,000/MMBTU/hr. This is consistent with utility boiler experience, which found that SCR on clean fuel applications would cost under half the price of SCR on coal applications of similar output. This is also consistent with the cost of reduction

as reported by a technology supplier of a urea SCR system of \$7,500/MMBTU/hr for a 100 MMBTU/hr gas-fired boiler.⁸

Table III-8a shows the cost effectiveness of SCR on a 350 MMBTU/hr industrial boiler for an 80% NO_x reduction from 0.45 lb/MMBTU while assuming a capital cost of \$10,000/MMBTU/hr. In this case, SCR can control NO_x for under \$2,000/ton on an annual basis for most capacity factors of interest. Another analysis is performed for a more expensive SCR, at \$15,000/MMBTU/hr (Table III-8b). In this case, SCR on higher capacity factor boilers (over 65%) can provide NO_x reduction at a cost of under \$2,000/ton on an annual basis. In both cases the cost effectiveness in \$/ton is over \$3,000/ton under most circumstances when control is only on a seasonal basis.

Table III-8a: Cost Effectiveness for SCR NO_x Reduction on a 350 MMBTU/hr Coal-Fired Boiler - 80% NO_x Reduction from 0.45 lb/MMBTU and Capital Cost of \$10,000/MMBTU/hr			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$5,046	\$3,677	\$2,953
Annual	\$2,179	\$1,609	\$1,307

Table III-8b: Cost Effectiveness for SCR NO_x Reduction on a 350 MMBTU/hr Coal-Fired Boiler - 80% NO_x Reduction from 0.45 lb/MMBTU and Capital Cost of \$15,000/MMBTU/hr			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$7,030	\$5,051	\$4,004
Annual	\$3,006	\$2,181	\$1,745

SCR on a gas-fired facility will have a lower capital cost due to the lower catalyst volume, but will reduce NO_x from a lower baseline NO_x. Table III-9a shows the estimated cost effectiveness for an SCR on a 350 MMBTU/hr gas-fired facility with a capital cost of \$5,500/MMBTU/hr (\$1.925 million) that reduces NO_x 80% from 0.15 lb/MMBTU baseline. For annual control, NO_x reduction can be achieved at a cost effectiveness approaching \$2,000/ton at higher capacity factors. However, for seasonal control, cost of NO_x reductions increases by a factor of about two. Since there are numerous gas-fired boilers in the range of 100 MMBTU/hr, analysis was also performed for SCR on a gas-fired boiler of this size (Table III-9b). As indicated, NO_x reductions are more costly on a smaller boiler. Except in the case of high capacity factor units that are required to reduce NO_x on an annual basis, the cost of NO_x reduction will exceed \$6,000/ton.

Table III-9a: Cost Effectiveness for SCR NO_x Reduction on a 350 MMBTU/hr Gas-Fired Boiler			
80% NO_x reduction from 0.15 lb/MMBTU and Capital Cost of \$5,500/MMBTU/hr			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$8,519	\$6,064	\$4,764
Annual	\$3,626	\$2,603	\$2,062

Table III-9b: Cost Effectiveness for SCR NO_x Reduction on a 100 MMBTU/hr Gas-Fired Boiler			
80% NO_x reduction from 0.15 lb/MMBTU and Capital Cost of \$7,500/MMBTU/hr			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$14,479	\$10,190	\$7,919
Annual	\$6,110	\$4,322	\$3,376

Reburning

Reburning is another technology available for industrial boilers, but most experience has been on utility boiler applications. Conventional Gas reburning is in use at industrial boilers operated by Kodak in Rochester, New York.¹ A version of gas reburning called Methane DeNO_x is being commercially used at Cogentrix in Richmond, Virginia.¹⁰

Another type of gas-reburning, Fuel Lean Gas Reburn (FLGRSM), has been employed on several utility units, but is also applicable to industrial units. For utility units, Conventional Gas Reburn costs about \$15/KW (or about \$1,500/MMBTU/hr) to deploy and FLGR deployment costs about \$7-8/KW (or about \$800/MMBTU/hr). For industrial applications, a cost of about \$2,000/MMBTU/hr for Conventional Gas Reburn and \$1,000/MMBTU/hr for FLGR was assumed. For Amine Enhanced FLGR (AEFLGRSM), which has been deployed on several electric utility units, a cost of \$2,500/MMBTU/hr was assumed for this report.

In cost analysis for the three cases of conventional gas reburning, FLGR, and AEFLGR, a 350 MMBTU/hr boiler that fires coal as a primary fuel is assumed to have a baseline NO_x level of 0.45 lb/MMBTU with natural gas costs of \$0.75/MMBTU higher than coal ("fuel differential") (see Tables III-10a, III-11a and III-12a). Tables III-10b, III-11b and III-12b show results of similar calculations, but at a higher fuel differential of \$1.00/MMBTU.

These gas-based technologies provide NO_x reduction below \$2,000/ton under most conditions when the fuel differential is \$0.75/MMBTU. However, these technologies are sensitive to the incremental fuel cost of gas over coal. When the fuel cost differential increases to \$1.00/MMBTU, the cost of using conventional gas reburn increases by about \$400/ton of NO_x reduced. The same fuel differential increases the cost of reducing NO_x with FLGR and AEFLGR by about \$200/ton and \$100/ton, respectively.

Various forms of gas reburning could be used on facilities firing other fuels. For oil-fired facilities, particularly those firing residual oil, similar results might be possible if the furnace could technically accommodate the reburning system. Natural gas facilities could also utilize this technology, but in most cases it is expected that gas-fired facilities will utilize Low-NOx Burner technology rather than reburning because it is likely to be a simpler retrofit and because many gas-fired furnaces may be too small to permit the use of reburning.

Table III-10a: Cost Effectiveness of NOx Reduction by Conventional Gas Reburn, Assuming 55% NOx Reduction from 0.45 lb/MMBTU, 20% Gas Injection, and \$0.75/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$2,665	\$2,215	\$1,975
Annual	\$1,810	\$1,625	\$1,520

Table III-10b: Same as 3.10a, Except \$1.00/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$3,097	\$2,613	\$2,373
Annual	\$2,208	\$2,019	\$1,920

Table III-11a: Cost Effectiveness of NOx Reduction by FLGR, Assuming 35% NOx Reduction from 0.45 lb/MMBTU, 6% Gas Injection, and \$0.75/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$2,000	\$1,565	\$1,330
Annual	\$1,170	\$985	\$890

Table III-11b: Same as 3.11a, Except \$1.00/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$2,220	\$1,756	\$1,523
Annual	\$1,362	\$1,179	\$1,083

Table III-12a: Cost Effectiveness of NO_x Reduction by AEFLGR, Assuming 60% NO_x Reduction from 0.45 lb/MMBTU, 6% Gas Injection, NSR=1.2 and \$0.75/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$2,455	\$1,965	\$1,700
Annual	\$1,520	\$1,315	\$1,210

Table III-12b: Same as III-12a, Except \$1.00/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$2,604	\$2,073	\$1,812
Annual	\$1,631	\$1,425	\$1,316

NSR is a measure of the urea or ammonia injection rate.

Coal Reburning is a technology used at Kodak Park (Case Study BLR-8 in Chapter IV). Natural gas was not readily available to Boiler #15 for use as a reburn fuel and a substantial portion of the coal reburning project cost was borne by cofunders who wished to demonstrate the technology. Reference 1 found this to be a costly method for NO_x reduction that may be applicable only in specific situations. In most cases it is expected that coal reburning will be too costly to employ in most industrial boilers from a capital cost perspective. Technical challenges will also limit its applicability, and other techniques may be preferred economically and technically. However, there may be special situations where it may be applicable to industrial boilers.

D. Gas Turbines

NO_x control methods for gas turbines include methods that reduce NO_x that is generated in the combustion process itself (primary controls) and methods that reduce NO_x after it is generated in the combustion process in the exhaust gas (secondary controls). In general, primary control methods are less costly and provide a lesser level of control, and secondary methods are more costly but do provide a much higher level of NO_x control.

D.1 Cost Effectiveness of Primary Methods of Controlling NO_x from Gas Turbines

Primary methods of NO_x control minimize the amount of NO_x generated in the turbine combustor. The two most widely used methods include Dry Low NO_x technology and Diluent Injection technology.

Dry Low NO_x (DLN)

Dry Low NO_x has been employed on numerous gas turbines in the U.S. Several case studies that use DLN are included in this report. Capital cost was the primary cost associated with implementing Dry Low NO_x on the Solar and General Electric (GE) turbines that were evaluated.

Allison offers a DLN retrofit that is fairly low in capital cost, though this retrofit is designed for base-loaded operation under a fairly limited load range.¹¹ In order to explore a broader range of turbine applications and provide conservative results, Solar turbine retrofits designed for wider load ranges are evaluated in this report.

The cost of NO_x reduction by DLN is very sensitive to the capacity factor of the turbine. Analysis of the case study data showed that there could be substantial variation in capital cost measured in terms of dollars/horsepower (\$/hp). This is due to different turbine types, variations in turbine designs over the years, and different scopes of supply that often result from turbine differences or simply from additional work the user found convenient at the time of retrofit. For some applications, this additional work can include the addition of sophisticated control retrofits necessary to utilize the DLN technology or equipment overhauls performed at the time of retrofit. In this latter case, when it was known that work was performed that was not essential for the DLN retrofit, its cost was not included for cost analyses in this chapter.

For the analysis in this report, \$750,000 was assumed as the total capital cost to retrofit one Solar Centaur turbine (4,700 hp at \$160/hp) and \$1,950,000 to retrofit one Solar Mars turbine (13,000 hp at \$150/hp). These values are similar to the reported cost in the case studies. Also, note that these were the total project costs the owners attributed to the project, which may include project management or other charges associated with the project beyond the equipment and installation. Fixed O&M costs were shown to be about \$15,000 per year for each facility, which usually involved more than one turbine. No variable O&M charges were attributed to the DLN retrofit in this analysis. In the case studies, owners reported no adverse change in turbine heat rate. In fact, heat rate was improved when converting a turbine from water or steam injection to DLN.

The economic analysis in this report differs from that shown in the Case Studies GT-1, GT-2, GT-3 and GT-7 that involve Solar Centaurs and Solar Mars turbines (Chapter IV) in several ways. First, the analysis performed in this report averages the estimates from a discounted cash flow approach and a first-year estimate, versus just a first-year estimate for the case studies. The discounted cash flow method of this report uses a fifteen-year project life at a 12% discount rate, and the first-year analysis in this report uses a fifteen-year life and discount rate of 10% (Capital Recovery Factor or CRF = 13.1%). The case study analyses are based on a ten-year life with an 8% discount rate (CRF = 14.9%). These assumptions can have a significant effect on the results. Second, in this study, indirect costs such as property taxes are explicitly stated while the case study analysis makes assumptions regarding other indirect costs (administration, etc.) and applies an annual charge equal to a certain percentage of the capital cost. Results of past studies suggest that using this percentage of total capital invested tends to overestimate the indirect costs, especially on very capital-intensive air pollution technology retrofit projects discussed in this report.¹ Finally, since the installations usually involve multiple turbines rather than a single turbine, the analysis in this report assumes multiple turbine installations. On the other hand, the analyses in the case studies are prepared for single turbine installations. Hence, all of these differences in the analysis approach contribute to differences in results.

Tables III-13 and III-14 show analysis for Solar Centaur and Mars turbines, respectively. These turbines are widely used in industry, as are the Solar Taurus and turbines from Allison and Dresser Rand. As Tables III-13 and III-14 show, retrofit of conventional combustion technology with DLN can cost less than \$2,000/ton. DLN retrofits on turbines operated at a high capacity factor

(95%) can reduce NO_x emissions in the range of 70% on an annual basis at a cost of about \$1,300/ton for a Mars turbine and by about 63% for about \$1,900/ton for a Centaur turbine. At lower capacity factors or for seasonal control, the costs are higher. For example this analysis shows that the owner of a Solar Centaur with only 45% capacity factor may find the cost of reducing ozone-season NO_x to be over \$9,000/ton with DLN. In this case, other approaches such as water injection may be more attractive.

Table III-13. Cost Effectiveness (\$/ton) for Two Solar Centaur (7000 hp each) Retrofit with DLN for Reducing NO_x from 135 to 50 ppm (63% reduction)				
Time Period of Control and NO _x Reduction	Capacity Factor			
	0.45	0.65	0.85	0.95
Seasonal 135 to 50 ppm	\$9,483	\$6,565	\$5,020	\$4,492
Annual 135 to 50 ppm	\$3,951	\$2,736	\$2,092	\$1,872
If the actual baseline NO _x level were lower, as in Case Study GT-7, the cost of control will be higher. New Centaur Turbines equipped with SoloNO _x TM technology are guaranteed at 25 ppm. ¹²				

A 75 MW turbine is evaluated next to represent larger turbines. Case Study GT-4 addresses a Dry Low NO_x retrofit of 75 MW GE Frame 7 turbines originally equipped with water injection for NO_x reduction. The cost effectiveness of retrofitting turbines with traditional combustion technology and no prior controls is also evaluated. While the case study GT-4 was a retrofit of a turbine that was originally equipped with water injection, for this study it is assumed that the retrofit would have cost about the same if the turbine had conventional combustion technology. This is probably a reasonable assumption for the purposes of this report. It is important to note that in the case study GT-4, the owner reported a significant improvement in the heat rate as a result of the DLN retrofit from water injection. As will be shown below, this improvement in heat rate and reduced water treatment costs help to make a DLN a NO_x control retrofit option that can pay for itself.

Table III-14. Cost Effectiveness (\$/ton) for Retrofit of Two Solar Mars (2x13,000 hp) Reducing NO_x from 167 to 50 ppm (70% reduction)				
Time Period of Control and NO _x Reduction	Capacity Factor			
	0.45	0.65	0.85	0.95
Seasonal 167 to 50 ppm	\$6,640	\$4,597	\$3,515	\$3,145
Annual 167 to 50 ppm	\$2,767	\$1,915	\$1,465	\$1,311
If the actual baseline NO _x level were lower, as in Case Study GT-8, cost of control will be higher. New Mars turbines equipped with SoloNO _x TM technology are guaranteed at 25 ppm. ¹²				

Case Study GT-4 showed a capital cost of the retrofit equal to \$49/KW, or about \$36/hp. It is reasonable that for this larger turbine the cost of the retrofit would be less, when measured on a \$/KW or \$/hp basis, than for a smaller turbines, such as Solar Centaur and Solar Mars described earlier. The cost of \$36/hp for the larger 75 MW turbine is about one fourth to one fifth of the amount (in \$/hp) that was used for the cost of DLN retrofits of industrial turbines in the range of 3-10 MW.

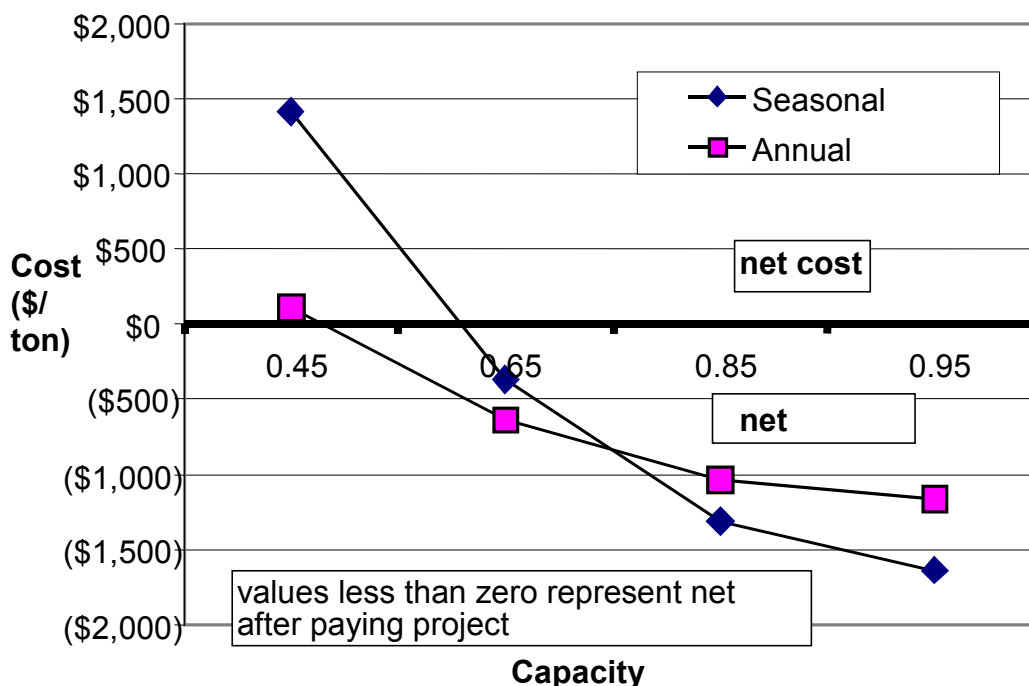
As shown in Table III-15, a DLN retrofit of a 75 MW GE Frame 7 equipped with original combustion technology will achieve 90% NO_x reduction at a cost effectiveness well below \$1000/ton under almost all of the conditions evaluated.

Table III-15. Cost Effectiveness for 75 MW GE Turbine Retrofit with DLN from Conventional Combustion, Reduction from 154 ppm to 15 ppm (90% reduction)				
Time Period of Control	Capacity Factor			
	0.45	0.65	0.85	0.95
Seasonal	\$1,126	\$779	\$596	\$533
Annual	\$469	\$325	\$248	\$222

Table III-16 shows the estimated cost of reducing NO_x with a DLN retrofit on a turbine that is originally equipped with water injection. These results are very interesting. For most conditions, reduction of NO_x by a DLN retrofit on a turbine originally equipped with water injection will actually pay for itself due to reduced fuel costs and reduced annual costs associated with the operation of the water injection equipment. Of course, this analysis is sensitive to the actual level of efficiency improvement. In case study GT-4, the owner reported a significant improvement in heat rate as a result of the DLN retrofit from water injection, and this efficiency improvement was used in the present analysis. Because the cost savings from reduction in purified water use were not provided in the case study, estimated savings from reduction in purified water consumption were estimated from Table 6-5 of Reference 6 adjusting the water treatment costs to 1999 dollars assuming 2.6% inflation. The results of Table III-16 are plotted in Figure III-1, which show that any project with annual controls and a capacity factor greater than 45% pays for itself.

Table III-16. Cost Effectiveness for 75 MW Turbine Retrofit with DLN from Water Injection, Reduction from 42 ppm to 15 ppm				
Time Period of Control	Capacity Factor			
	0.45	0.65	0.85	0.95
Seasonal	\$1,414	(\$369)	(\$1,313)	(\$1,636)
Annual	\$107	(\$636)	(\$1,029)	(\$1,164)

Figure III-1: Cost Effectiveness (\$/ton of NO_x reduced) of Reducing NO_x from a 75 MW Turbine by DLN Retrofit of Turbine Originally Equipped with Water Injection



The cost estimates for seasonal control shown in Table III-16 and Figure III-1 are based on the assumption that the DLN conversion is added to achieve seasonal controlled levels that are lower than what can be achieved by water injection alone. It is also assumed that the baseline condition is the use of water injection on a year-round basis. To compare a DLN retrofit to water injection only during the ozone season, it would be appropriate to compare the results in Table III-16 to the results shown in the section below.

Diluent Injection

DLN retrofit described above offers lower NO_x emissions than diluent injection while firing natural gas, and offers several cost and operating advantages, generally making diluent injection a less preferred approach on turbines with higher capacity factors. However, as will be seen, for very low capacity factors that may occur for peaking turbines, diluent injection may be more desirable than DLN. This is because diluent injection has a lower capital cost and because the higher operating cost of diluent injection has little effect on the overall economics due to the very limited operating hours (of the order of 200 to 400 hours a year). Another case where diluent injection may

be the only option is any situation where a manufacturer does not offer DLN (for example when turbines fire fuel oil).

The costs for diluent injection include significant operating costs but low capital costs. Operating costs include the costs of purified water or steam, as well as increased fuel costs due to the reduced efficiency that results from water injection. Water and steam injection both have an impact on heat rate (about 2-4% for water injection and about 1% for steam injection). This economic impact is partly offset by an increase in available power output of roughly 3-5% (Ref 6, Table 5.10), but this additional power frequently is not useful due to the limitations of the generator or compressor that is being driven by the turbine. For this reason, the cost analysis of diluent injection did not include a factor for the increase in turbine power. There may be situations, however, where this additional power may be useful and should be included in the analysis.

PSE&G of New Jersey is planning to retrofit 24 peaking turbines at their Edison, NJ facility with high-pressure water injection.¹³ Each turbine is about 21 MW in size and will reduce NO_x from about 125 ppm to about 50 ppm while firing gas and from about 180 ppm to about 50 ppm when firing oil. The total capital cost is \$9 million. Water usage is about 10 gallons per turbine per minute and costs about \$0.025/gallon. These turbines only operate a few hundred hours per year (around 200 hours) for summer peak duty and spinning reserve.¹³

Using the cost estimates from PSE&G, an estimate of cost of control for various scenarios can be performed. These estimates are consistent with the general assumptions used in this report and do not reflect PSE&G's analysis, which was not provided for this report. Table III-17 shows estimates of cost effectiveness for diluent injection on turbines with regular use, as well as for peaking duty situations of 200 hours and 400 hours. As shown in Table III-17a, the cost of NO_x reduction for peaking duties is about \$3,500 to nearly \$7,000/ton of NO_x removed when firing gas, and the incremental cost of electricity generation ranges from \$6.00/MWhr to over \$11.00/MWhr. Table III-17b shows the results of similar analysis when firing distillate oil. The incremental cost of generation is high enough that, for many situations, an increase of this size to generation cost may render the unit uneconomical for operation. But because these peaking turbines are operated only when the value of electricity is very high (on hot, summer days), the turbines continue to be economical to operate under these conditions. Recalling that the analysis does not give credit for additional power and assumes that the efficiency penalty will be 4%, actual operating experience may show that the retrofit economics are more favorable than is shown. It should be noted that the analyses of Table III-17a and b are also sensitive to fuel price.

Table III-17a: Estimated Cost Effectiveness for Diluent Injection on Twenty-Four 21-MW Peaking Turbines. Reduction from 125 ppm to 50 ppm (gas firing)

Time Period of Control	Peaking Duty Hours		Capacity Factor		
	200	400	0.45	0.65	0.85
Seasonal (\$/ton)	\$6,828	\$3,684	\$1,217	\$989	\$867
Seasonal (\$/MWhr)	\$11.38	\$6.14	\$0.85	\$0.69	\$0.60
Annual (\$/ton)			\$784	\$688	\$638
Annual (\$/MWhr)			\$1.31	\$1.15	\$1.06

Table III-17b: Estimated Cost Effectiveness for Diluent Injection on Twenty-Four 21-MW Peaking Turbines. Reduction from 180 ppm to 50 ppm (distillate oil firing)

Time Period of Control	Peaking Duty Hours		Capacity Factor		
	200	400	0.45	0.65	0.85
Seasonal (\$/ton)	\$4,212	\$2,450	\$1,031	\$899	\$829
Seasonal (\$/MWhr)	\$12.17	\$7.08	\$1.24	\$1.08	\$1.00
Annual (\$/ton)			\$781	\$726	\$697
Annual (\$/MWhr)			\$2.26	\$2.10	\$2.01

In the analysis for the case where the turbine operates year-round at an average capacity factor, it was assumed that the water injection occurs only when there is a need for control, i.e., only during the summer for seasonal control and year-round for annual controls. It is important to note that, while the cost per ton to reduce NO_x is higher with seasonal controls, the impact on the generation cost is reduced. This is because much of the cost of using this technology is associated with increased heat rate and water usage during water injection.

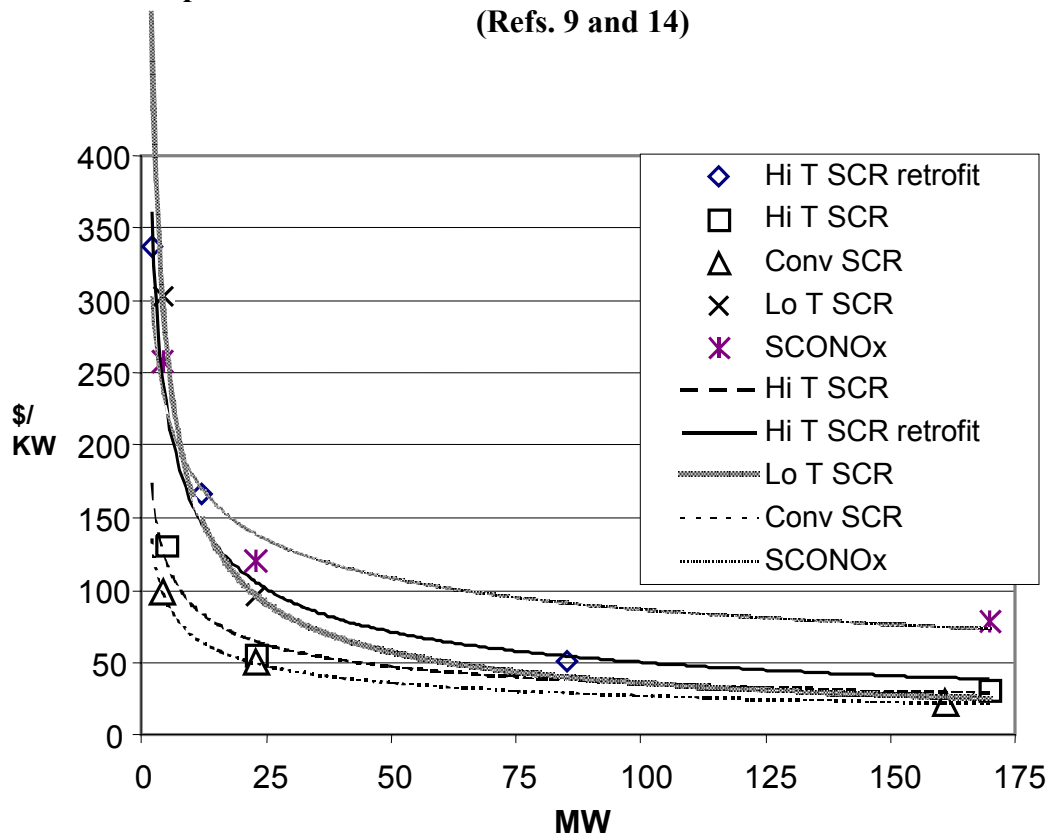
Finally, comparing the results in Table III-17a to those in III-17b, it is observed that, while the cost per ton of NO_x removed is higher with gas, the impact on generation cost is lower. This is because the baseline NO_x when firing gas is lower than when firing oil; however, the cost of distillate oil is higher than gas, increasing the cost of the heat rate when firing oil.

D.2 Cost Effectiveness of Secondary Methods of Controlling NO_x from Gas Turbines

Secondary control methods for exhaust treatment are generally used when primary control methods cannot provide sufficiently low NO_x levels to meet regulatory emission limitations. Although secondary methods are more expensive to install and operate, they do provide substantially higher level of NO_x reductions compared to primary methods.

Figure III-2 shows the capital cost (\$/KW) of various post-combustor technologies. The curves were generated by fitting a power equation of the form $y = ax^{-b}$, where a and b are constants that are determined in the regression analysis. Reference 15 provided the retrofit cost of a high-temperature SCR system, while Reference 11 provided the incremental cost of the various technologies for a new turbine installation. Additionally, although the cost effectiveness of SCONOXTM is not addressed in detail in this chapter, it is included in the figure because the data was included in Reference 11. Clearly, for all of these technologies there is a very strong scaling effect, especially for turbines well below the 50 MW size.

Figure III-2: Capital Cost of Gas Turbine Exhaust Treatment NO_x Reduction Technologies (Refs. 9 and 14)



Retrofit of Simple Cycle Turbines with High-Temperature SCR

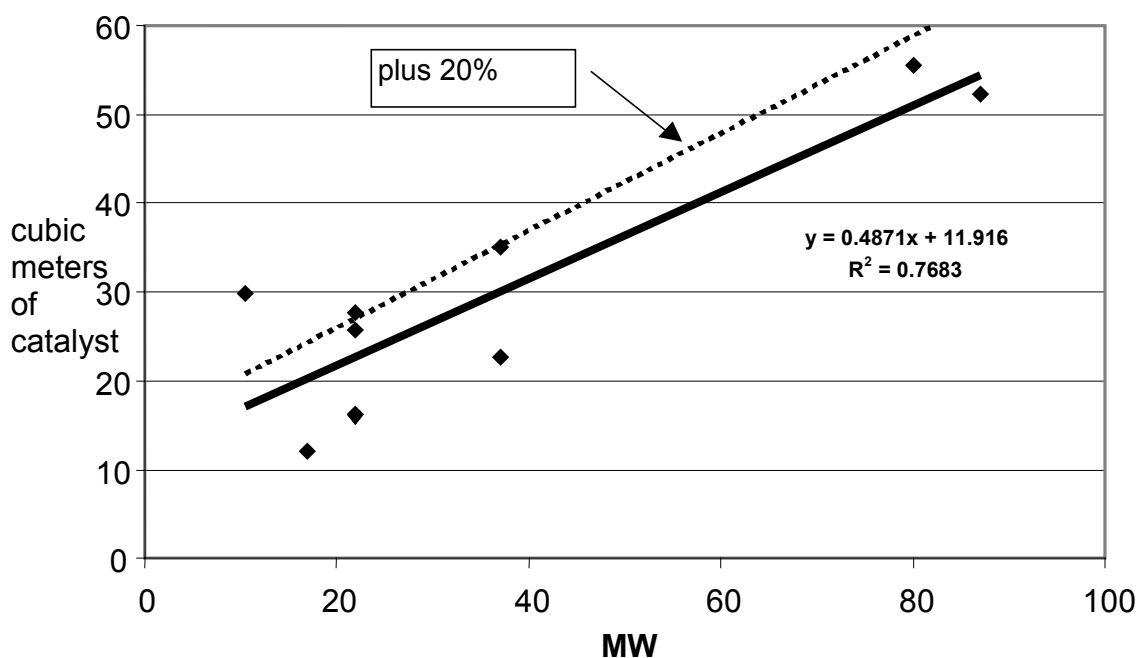
Retrofit of a simple cycle turbine or placement of an SCR between the turbine and the Heat Recovery Steam Generator (HRSG) on a combined cycle system requires the use of a high-temperature SCR catalyst, which is somewhat more expensive than normal systems (Figure III-2). One supplier mentioned that they typically offer fully-installed SCRs for simple-cycle systems, including the catalyst, reactor, ammonia storage, injection and controls, commissioning, etc., at a price of about \$50/KW to \$70/KW.¹⁴ This is consistent with a rough cost estimate from another supplier that indicated a price for an 80 MW GE Frame 7 of about \$4.1 million (\$2.5 million in equipment and \$1.6 million in installation for a capital cost of \$51/KW), not including balance-of-plant items. Systems with more complex duct modifications will typically cost at the high end of this range. For smaller, industrial turbines, such as in Solar's 2-12 MW product line, the same supplier indicated a cost of about \$200,000 to \$1.2 million, with installation ranging from \$275,000-\$800,000. For these smaller, simple-cycle turbines, the cost of high-temperature SCR is in the range of \$167/KW to \$337/KW.¹⁵ Clearly, there are significant economies of scale for this technology that make the cost in \$/KW much lower for larger turbines.

The size of the needed catalyst needs to be estimated to do the cost analysis of the SCR system. Catalysts need to be replaced periodically, and although the catalyst replacement cost is not a large component of the overall expense, it is not insignificant. Therefore, it is necessary to have a good estimate of the catalyst size and its cost. Figure III-3 shows catalyst size plotted as a function

of turbine size (in megawatts) for turbine SCR systems addressed in Reference ¹⁶. This plot includes three different types of catalyst types (metal plate, ceramic honeycomb and metal honeycomb), as well as different turbine suppliers, and some different conditions (with or without water injection, and some dual-fuel while others firing only gas), providing enough data for a good linear correlation.

The data in Figure III-3 has some limitations. First, Reference 16 is nearly ten years old and catalyst technology has improved, reducing the necessary catalyst volume. Second, the SCR applications considered in this report are capable of greater NO_x reductions, require lower level of ammonia slip guarantees, and include high- and low-temperature catalysts. These factors combine to require slightly more catalyst volume. These factors indicate that an increase of the original regression line by 20% is reasonable. While this adjustment is, at best, approximate, it should be adequate for the purposes of these estimates. As a comparison for this new relationship between catalyst size and plant size, Reference 11 uses an approximation of 30 ft³/MW for conventional, low-temperature and high-temperature catalysts, which would result in a slightly higher estimate of catalyst volume at the larger size ranges and a slightly lower estimate at the low ranges than using Figure III-3. In this report, Figure III-3 will be used to estimate catalyst volume for all SCR types.

Figure III-3: Cubic Meters of SCR Catalyst for Turbine with HRSG (Ref. 16)



High-temperature SCR is economically attractive for simple cycle turbines because it is well suited for the high-temperature exhaust of a simple-cycle turbine. In many cases, a turbine equipped with an HRSG would not be retrofitted with a high-temperature SCR because of lack of enough space between the turbine and the HRSG. Additionally, most HRSGs built in the last decade are designed to accommodate a conventional SCR catalyst, regardless of whether or not an SCR is initially provided as part of the HRSG. For this reason, combined-cycle turbines are most often retrofitted with a conventional SCR. Therefore this analysis performs all estimates for high-temperature SCR on simple cycle retrofits.

Using the data for the catalyst size in Figure III-3, an assumption of \$14,000/m³ of catalyst, and a six-year life (assuming that natural gas is fired nearly all the time), the cost effectiveness of high-temperature SCR on simple cycle turbines was developed (Tables III-18 a through e). The analysis is assumed to apply to either a high-temperature catalyst or to a conventional SCR catalyst with some air-cooling.

Table III-18a: Cost Effectiveness for SCR Retrofit on Simple Cycle 75 MW Gas Turbine with Baseline NOx of 154 ppm and Controlled to 15 ppm (90% Control)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$1,853	\$1,410	\$1,176
Annual	\$849	\$664	\$566

Table III-18b: Cost Effectiveness for SCR Retrofit on Simple Cycle 75 MW Gas Turbine with Baseline NOx of 42 ppm and Controlled to 7 ppm (83% Control)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$6,969	\$5,210	\$4,278
Annual	\$2,980	\$2,247	\$1,859

Table III-18c: Cost Effectiveness for SCR Retrofit on Simple Cycle 75 MW Gas Turbine with Baseline NOx of 15 ppm and Controlled to 3 ppm (80% Control)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$20,075	\$14,943	\$12,227
Annual	\$8,441	\$6,303	\$5,171

Table III-18d: Cost Effectiveness for SCR retrofit on Simple Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 142 ppm and Controlled to 15 ppm (89% Control)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$7,965	\$5,872	\$4,763
Annual	\$3,395	\$2,523	\$2,061

Table III-18e: Cost Effectiveness for SCR retrofit on Simple Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 42 ppm and Controlled to 5 ppm (88% Control)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$27,020	\$19,835	\$16,031
Annual	\$11,335	\$8,341	\$6,756

Retrofit of Combined-Cycle Turbines with Low-Temperature SCR or Conventional SCR

Combined-cycle turbines equipped with an HRSG generally cannot be retrofitted with a high-temperature SCR because there usually is not enough room between the turbine and the HRSG for the catalyst. Moreover, most HRSGs built in the last decade are designed to accommodate a conventional SCR catalyst, regardless of whether or not an SCR was initially provided as part of the HRSG. For these reasons, combined-cycle gas turbines are rarely retrofitted with high-temperature SCR.

If the HRSG design is such that it will readily accommodate a conventional SCR but could possibly accommodate a low-temperature SCR, the user will usually choose a conventional SCR because of its lower cost. However, if the HRSG does not have enough space to accommodate a conventional SCR, or there is inadequate distance for good mixing of the ammonia with the exhaust gas between the ammonia injection grid and the conventional catalyst, a low temperature SCR system may be the better choice. Turbines that have duct burners and are required to attain high reductions by SCR are more likely to have inadequate mixing distance between the location for the ammonia injection grid and the HRSG catalyst space. In these cases, low-temperature SCR may be an appropriate technology choice.

From Figure III-2, the capital cost of a high-temperature SCR retrofit on a simple cycle turbine is about the same as the incremental cost of low-temperature SCR on a gas turbine with an HRSG. The cost of retrofitting a combined-cycle turbine with a low-temperature SCR will then be roughly the same as the cost of retrofitting the same model turbine in a simple-cycle arrangement with high-temperature SCR. The cost effectiveness values would be expected to be similar as well. Because a principal benefit of low-temperature SCR is the low cost to retrofit, it is assumed that the retrofit cost is roughly equal to the capital cost shown in Figure III-2 for the turbine sizes of interest.

Tables III-19a through III-19e indicate the cost effectiveness of applying conventional SCR on a combined-cycle gas turbine that can readily accommodate the system. As noted earlier in this section, it is expected that the cost-effectiveness of low-temperature SCR on a combined-cycle gas turbine will be very similar to that of high-temperature SCR on similarly sized simple-cycle gas turbines.

Table III-19a: Cost Effectiveness for Conventional SCR on Combined Cycle 75 MW Gas Turbine with Baseline NO_x of 154 ppm and Controlled to 15 ppm			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$1,275	\$1,010	\$869
Annual	\$608	\$497	\$439

Table III-19b: Cost Effectiveness for Conventional SCR on Combined Cycle 75 MW Gas Turbine with Baseline NO_x of 42 ppm and Controlled to 7 ppm			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$4,673	\$3,620	\$3,062
Annual	\$2,024	\$1,585	\$1,353

Table III-19c: Cost Effectiveness for Conventional SCR on Combined Cycle 75 MW Gas Turbine with Baseline NO_x of 15 ppm and Controlled to 3 ppm			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$13,376	\$10,306	\$8,680
Annual	\$5,650	\$4,371	\$3,693

Table III-19d: Cost Effectiveness for Conventional SCR on Combined Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NO_x of 142 ppm and Controlled to 15 ppm			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$4,659	\$3,583	\$3,013
Annual	\$2,018	\$1,569	\$1,332

Table III-19e: Cost Effectiveness for Conventional SCR on Combined Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NO_x of 42 ppm and Controlled to 5 ppm			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$15,672	\$11,978	\$10,023
Annual	\$6,607	\$5,068	\$4,253

E. Internal Combustion (IC) Engines

E.1 Cost Effectiveness of Primary Methods of Controlling NO_x from IC Engines

Primary Control methods reduce NO_x that is formed in the engine. These methods are most often performed first, since they provide moderate reductions at moderate costs. The cost and performance of these methods are frequently very specific to the particular engine, particularly for more involved primary methods such as Low-Emission Combustion (LEC). For some engines, such retrofits may not be available. Of course, as in the other analyses in this chapter, it is assumed that each method is technically feasible for the situation being evaluated.

Ignition Timing Retard

The data below is for Tennessee Gas Pipeline in Mercer, PA, which operates six 1100 hp engines using ignition timing retard (Case Study IC-6). Reported costs for this project are shown in Table III-20.

Table III-20: Experience and Costs of Ignition Timing Retard (Case Study IC-6)	
Months of Operation (as of Oct '99)	54
Increased Fuel Consumption Cost	\$5,000/year per engine
Project Cost	\$4,000 per engine
Estimated Additional Maintenance	\$1,000/year per engine
Additional Cost of Testing	\$600/yr per engine
Baseline NOx Emissions	10 gm/hp-hr
Controlled NOx Emissions	9 gm/hp-hr
Number of Forced Outages	0
Total Lost Operating Hours	0

The approximate cost of NOx reduction is outlined in Table III-21. It is interesting to note that the cost effectiveness for the 10% NOx reduction does not change very much as capacity factor changes. This is because the largest cost item is increased fuel consumption. Although ignition timing retard will produce NOx reductions year round, the NOx reductions that occur outside of the ozone season are not counted in the seasonal control scenario.

Table III-21: Estimated Cost Effectiveness (\$/ton of NOx removed) for Ignition Timing Retard on six 1,100 HP Engines from 10 gm/hp-hr to 9 gm/hp-hr (10% Reduction)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$1640	\$1530	\$1,476
Annual	\$685	\$640	\$615

Ignition timing retard tends to be less effective at reducing NOx on spark-ignited engines than injection timing retard on compression-ignition engine (see below). However, both methods provide only small to moderate NOx reductions, making these methods of control of much less interest than other methods.

Injection Timing Retard

Injection timing retard is a very cost effective way to achieve small to moderate NOx reductions of 15% to about 30% on diesel engines. No case study data was available for the costs of injection timing retard, however, information from Reference 16 shows that costs for ignition and injection timing retards are similar and so it will be assumed that the capital cost is about the same as shown in Table III-20. Estimates of cost effectiveness with a 25% NOx reduction are shown in Table III-22.

Table III-22: Estimated Cost Effectiveness (\$/ton of NOx removed) for Injection Timing Retard on six 1,100 HP Engines from 10 gm/hp-hr to 7.5 gm/hp-hr (25% Reduction)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$657	\$612	\$589
Annual	\$274	\$255	\$245

Air/Fuel Ratio Changes and High-Energy Ignition

This method has been used to reduce NOx on several large, two-stroke, reciprocating engines of 2000 hp to 2700 hp with integral gas compressors (Case Studies IC-2, IC-3, IC-4). NOx reductions from baseline levels of 12 to 18 gm/hp-hr to controlled levels of about 5 to 8 gm/hp-hr were achieved in the case study examples - typically a little over 50% NOx reduction. On average, these retrofits cost \$22/hp (a range of \$12/hp to \$28/hp, primarily depending upon engine type). Fixed O&M was about \$8,000 for each site, with three to six engines per site. The particular type of engine being considered for air/fuel ratio changes will play a significant role in the cost and effectiveness of employing this method of NOx reduction. To develop a "typical" analysis, it was assumed that an installation of four 2,500-hp engines would achieve a reduction from 15 to 7 gm/hp-hr with a capital cost of \$22/hp. The results of this analysis are shown in Table III-23.

Table III-23: Estimated Cost Effectiveness (\$/ton of NOx removed) for High Energy Ignition/A-F Ratio Adjustment on four 2,500 HP engines from 15 to 7 gm/hp-hr (53% Reduction)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$385	\$315	\$280
Annual	\$160	\$130	\$115

Low-Emission Combustion (LEC)

A low-emission combustion retrofit is being employed on two 3400 hp engines at Tennessee Natural Gas' facility near Syracuse, NY (Case Study IC-7). The capital cost of retrofitting these engines was about \$340/hp, close to the value estimated from Reference ¹⁷. The cost effectiveness for this project is shown in Table III-24.

For smaller, medium-speed engines, a lower capital cost would be expected, on the order of \$200/hp.¹⁷ According to the California Air Resources Board BACT document on IC Engine controls (Ref. ¹⁸, Table D-1), Low-Emission Combustion offered up to a 90% reduction of NOx on natural gas engines and about 60-70% control for landfill gas engines. This difference is probably due to the lower initial NOx from the lower heating-value landfill gas. The cost estimates for a reduction scenario assuming 80% reduction from 15 gm/hp-hr to 3 gm/hp-hr for a natural gas engine, an installation cost of \$200/hp, and efficiency penalty of 0.5% for four 2500 hp engines, are shown in Table III-25.

**Table III-24: Cost Effectiveness for two 3,400 HP IC Gas Engines (low speed)
Equipped with Low-Emission Combustion Technology - 77% NO_x reduction from
13 gm/hp-hr**

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$2,296	\$1,594	\$1,222
Annual	\$957	\$664	\$509

**Table III-25: Cost Effectiveness for Four 2,500 HP IC Gas Engines (medium speed)
Equipped with Low-Emission Combustion technology - 80% NO_x Reduction from
15 gm/hp-hr**

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$1,100	\$765	\$585
Annual	\$460	\$320	\$245

Dual-fuel engines have much greater capital costs than engines firing a single fuel, which can be approximated by

$$\text{Capital Cost} = \$405,000 + (\$450 \times \text{hp})$$

for engines larger than 1,000 hp.¹⁷ For a 2,500-hp engine, the capital costs are projected to be about \$615/hp. Although NO_x reductions occur year round, the seasonal control scenario only takes credit for those NO_x reductions made during the ozone season. In this case, the total costs are the same regardless of the need for annual or seasonal control, resulting in the cost effectiveness numbers much greater for seasonal controls, even though the total cost and actual total NO_x reduction are the same.

As shown in Table III-26, NO_x reductions through Low-Emission Combustion on a dual-fuel engines with high capacity factors can generally be achieved for under \$1,000/ton for annual controls, and seasonal reductions can be achieved in the range of \$2,000/ton.

**Table III-26: Cost Effectiveness for Four 2,500 HP IC Dual-Fuel Engines Equipped
with Low-Emission Combustion Technology - 80% NO_x Reduction from 15 gm/hp-hr**

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$3,388	\$2,346	\$1,794
Annual	\$1,412	\$977	\$747

E.2 Cost Effectiveness of Secondary Methods of Controlling NO_x from IC Engines

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction is used for diesel and lean-burn Spark Ignition (SI) engines. Although two case studies were performed on IC engine SCR applications (case studies IC-1 and IC-5) only one provided information on the capital cost of the system (case study IC-5). It was therefore necessary to rely on other references for additional capital cost values. SCR capital costs for lean-burn engines can be approximated by

$$\text{Total Capital Cost of Lean Burn IC SCR} = \$310,000 + (\$72.7 \times \text{hp}),$$

and the total capital cost of SCR for diesel and dual-fuel engines can be estimated by

$$\text{Total Capital Cost of Diesel IC} = \$187,000 + (\$98 \times \text{hp}).^{17}$$

These equations include the cost of a continuous emission monitoring system (CEMS), estimated at \$85,000.¹⁷ If a CEMS is not necessary, this cost should be deducted from estimates obtained by the equations above.

Case Study IC-5 included information on capital and fixed operating costs, such as service and testing. The capital cost indicated in Case Study IC-5 was about 35% less than what is suggested by the equation above, even after deducting \$85,000 for the CEMS. The large difference in cost is most probably due in large part to the fact that the SCR in Case Study IC-5 was a new installation rather than a retrofit, and may also indicate that SCR technology is becoming less costly. For the analysis in this report, the cost from the equation will be used in keeping with the focus on retrofits.

Case Study IC-1 showed a service cost of \$78,000 per year for all three engines (\$26,000/engine) plus \$9,600 per year for testing. In contrast, Case Study IC-5 showed fixed O&M of only about \$2,000/year. One reason for the difference is that the facility at Plymouth Cogeneration (Case Study IC-5) has a CEMS, while the SYCOM system (Case Study IC-1) does not. The emissions testing costs in Case Study IC-5 are probably attributed to its CEMS. On the other hand, the value of the service contract for Case Study IC-1, at \$78,000 for three engines, may have to do with the type of duty (pumping versus cogeneration), the specific engine, or the SCR system (larger engines may have higher lube oil leakage that might require more frequent catalyst cleaning or an injection system requiring more frequent service). For this analysis, a middle value between the reported values for the two case studies is assumed for fixed O&M:

$$\$9,600 \text{ [for testing]} + \$14,000 \times (\text{hp}/9130) \text{ [for other fixed O\&M]}.$$

As in most situations, the cost effectiveness of an SCR for IC engines depends to a large extent on the initial NO_x level and the capacity factor. In fact, it has been argued that, besides the expense, there are technical reasons for not using SCR on engines with low capacity factors or those with highly variable loads, as addressed in Chapter II. Nevertheless, cost effectiveness values are shown for low capacity factor situations, recognizing that technical issues should be considered for any specific application.

The results of the analysis for SCR on IC engines are shown in Tables III-27a - d for gas and diesel engines. For each fuel type, a single large facility of three 3130 hp engines is considered, as well as a smaller installation of one 1800 hp engine. As shown in the tables, cost effectiveness numbers under \$1000/ton are possible for annual control under all situations when the capacity factor is above 45%. Only under conditions where the engine capacity factor is 10% are costs greater than \$2,000/ton.

Table III-27a: Cost Effectiveness for Three 3130 HP Diesel Engines Equipped with SCR Technology - 90% NO_x Reduction from 10 gm/hp-hr				
Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	\$4,246	\$1,044	\$763	\$614
Annual	\$1,838	\$503	\$386	\$324

Table III-27b: Cost Effectiveness for Three 3130 HP Gas-Fired Engines Equipped with SCR Technology - 90% NO_x Reduction from 10 gm/hp-hr				
Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	\$3,884	\$981	\$726	\$591
Annual	\$1,691	\$482	\$375	\$319

Table III-27c: Cost Effectiveness for One 1800 HP Diesel Engine Equipped with SCR Technology - 90% NO_x Reduction from 10 gm/hp-hr				
Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	\$6,866	\$1,626	\$1,166	\$922
Annual	\$2,929	\$746	\$554	\$453

Table III-27d: Cost Effectiveness for One 1800 HP Gas-Fired Engine Equipped with SCR Technology - 90% NO_x Reduction from 10 gm/hp-hr				
Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	\$8,245	\$1,950	\$1,397	\$1,104
Annual	\$3,508	\$886	\$655	\$533
Capacity Factor of 0.10 equates to 876 annual operating hours or 365 hours during the ozone season				

As described in Section II.C.2 of this report, manufacturers have developed simplified urea-SCR systems that are much less expensive to deploy on IC engines. This new technology stems from efforts to apply SCR to mobile source diesel engine applications. The lower capital cost of the simplified urea technology of Figure II-13 offers the potential for significantly reduced costs for controlling NO_x from diesel and lean-burn gas IC engines, particularly at low capacity factors and

on smaller horsepower engines. Analysis of a new Caterpillar engine (1971 HP diesel with uncontrolled NOx emissions of 7.62 gm/hp-hr) is shown in Table III-28a. These results showed cost effectiveness numbers below \$2000/ton for nearly all situations, including seasonal control. For uncontrolled emission levels more typical of existing engines, around 15 gm/hp-hr, the cost effectiveness is under \$1,000/ton for nearly all conditions evaluated (Table III-28b). It is important to note that because this SCR system uses a very simplified injection system that is adapted from diesel fuel injector technology, a lower fixed O&M cost of \$2,500/year is assumed.

Table III-28a: Cost Effectiveness for One 1971 HP Diesel Engine Equipped with Mobile-Source Derivative SCR NOx Reduction System Technology - 75% NOx Reduction from 7.62 gm/hp-hr

Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	\$3,080	\$1,043	\$864	\$769
Annual	\$1,491	\$643	\$568	\$528

Table III-28b: Cost Effectiveness for One 1971 HP Diesel Engine Equipped with Mobile-Source Derivative SCR NOx Reduction System Technology - 75% NOx Reduction from 15 gm/hp-hr

Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	\$1,751	\$716	\$625	\$577
Annual	\$944	\$513	\$475	\$455
Capacity Factor of 0.10 equates to 876 annual operating hours or 365 hours during the ozone season				

F. Cement Kilns

This section evaluates a number of demonstrated and potential technologies for reducing NOx emissions from cement kilns. Unlike the other three source categories evaluated in this chapter, which burn fuel to produce electric power and/or thermal energy, cement kilns burn fuel to produce a non-energy product – clinker. Clinker is ground to very fine particles to make the Portland Cement, which is an ingredient of concrete. Since Portland Cement is sold into large regional markets from multiple kilns (at the same site), there is some rationale to considering NOx levels in terms of pounds of NOx emitted per ton of clinker produced (lb. NOx/ton clinker). From an air pollution control perspective, it is appropriate to have kilns emit the lowest lbs. of NOx/ton clinker rather than kilns that have higher emission rates. From the perspective of a cement kiln owner, increases in the cost of clinker production resulting from implementation of NOx controls (in \$/ton clinker) will affect how they approach complying with NOx reduction requirements. In addition to providing cost data for NOx control in terms of dollars per ton of clinker (\$/ton clinker),

the analyses in this section also include the more traditional measure of cost effectiveness in dollars per ton of NO_x removed. This allows convenient comparison of costs of controlling NO_x from cement kilns to costs of NO_x reductions from other source categories such as gas turbines, and industrial and utility boilers.

F.1 Cost Effectiveness of Primary Methods of Controlling NO_x from Cement Kilns

The primary methods available for controlling NO_x depend on the type of kiln. A few kiln types are considered. In many cases, combustion controls result in the improvement of thermal efficiency of kiln, which reduces NO_x and reduces operating costs. As will be seen, in some cases these combustion upgrades can actually pay for themselves.

Low-NO_x Burners with Indirect Firing and Mid-Kiln Firing of Tires

This analysis uses information from Case Study CK-1 (California Portland Cement, Colton, California). A total NO_x reduction of 49% was achieved using both a Low-NO_x Burner (with indirect firing) and mid-kiln firing with tires. The capital cost of this program was \$7 million. The facility's fixed and operating costs also increased as a result of this approach. It is assumed that this approach is used on a year-round basis, even for ozone-season control scenarios. For seasonal control, only the NO_x reduced during the ozone season is considered in the cost-effectiveness calculation. This case study reported that facility production was reduced somewhat by the addition of tires. It is not known if this is a typical effect and because of the complexity it would add to the analysis this was not considered here. Where appropriate, however, this effect should be considered. The analysis also does not include lost revenues due to a four-week outage. This is probably small compared to the overall cost of the program.

The cost effectiveness of this approach is obviously dependent upon the uncontrolled baseline NO_x level. If the uncontrolled NO_x level is higher, the cost per ton of NO_x reduced is likely to be lower than what is shown below. Another important factor in the NO_x control costs is the reduced fuel costs resulting from the substitution of tires for the primary fuel (coal). The heating value of whole tires can vary from about 11,500 BTU/lb to nearly 17,000 BTU/lb,¹⁹ and steel-belted tires, though they have low heating value, also contribute valuable minerals (especially iron) to the cement. The tipping fee being paid for whole tires, net of delivery charges, varies between locations from \$20/ton to about \$200/ton.²⁰ Assuming an average heating value of about 14,000 BTU/lb, tires can provide cement kiln operators with an estimated revenue source of about \$0.71/MMBTU to \$7.14/MMBTU of tire fuel used. This effect is incorporated into the cost effectiveness calculations shown in Tables III-29 a through c.

Depending upon the tipping fees and operating conditions, the economic benefit of using tires as fuel for mid-kiln firing may be sufficient to provide a net economic benefit after paying for the cost of equipment (including the indirect firing and Low-NO_x Burner equipment) plus the cost of any additional operating expenses, though low tipping fees or low capacity factors may not provide net economic benefits. For this reason, the cement industry has implemented Low-NO_x Burners with mid-kiln firing of tires at many facilities, solely for its economic benefits. The combined technology of LNBs and mid-kiln firing, however, has the environmental benefit of moderate reductions in NO_x emissions.

Table III-29a: Cost Effectiveness of Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton Clinker on Two 96 Ton/hr. Kilns

No Tipping Fee.^x

Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, \$/ton NO _x	\$4,385	\$2,673	\$1,766
Seasonal, \$/ton clinker	\$2.42	\$1.48	\$0.97
Annual, \$/ton NO _x	\$1,827	\$1,114	\$736
Annual, \$/ton clinker	\$2.42	\$1.48	\$0.97

Table III-29b: Cost Effectiveness of Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton Clinker on Two 96 Ton/hr. Kilns

\$20/ton Tipping Fee.

Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, \$/ton NO _x	\$3,850	\$2,137	\$1,231
Seasonal, \$/ton clinker	\$2.13	\$1.18	\$0.68
Annual, \$/ton NO _x	\$1,604	\$891	\$513
Annual, \$/ton clinker	\$2.13	\$1.18	\$0.68

Table III-29c: Cost Effectiveness of Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton Clinker on Two 96 Ton/hr. Kilns

\$75/ton Tipping Fee.

Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, \$/ton NO _x	\$2,377	\$665	(\$242)
Seasonal, \$/ton clinker	\$1.31	\$0.37	(\$0.13)
Annual, \$/ton NO _x	\$991	\$277	(\$101)
Annual, \$/ton clinker	\$1.31	\$0.37	(\$0.13)

The net economic benefit effect of tire tipping fees is more pronounced on kilns that only use mid-kiln firing and do not install capital-requiring Low-NO_x Burner retrofits. NO_x reductions from these kilns are quite marginal (about 20%), but the elimination of the LNB significantly reduces capital costs. The prices of mid-kiln firing systems vary by kiln. The cost of a mid-kiln firing system for a 25 or 40 tons per hour (tph) long dry or long wet kiln is \$1,600,000, including a 20% charge for contingency.²¹ Reference²² generally listed lower costs, from as little as \$387,000 for a single preheater kiln (electrical installation and controls programming not included) to \$875,000 for

^x Notes for Tables III-29 to III-30. Values in parentheses indicate a net economic benefit to the user. It is assumed that the technologies do not significantly impact production. This assumption may not be correct in all cases and the impact on production should be considered when appropriate.

a complete system (all of project costs included), and as high as \$1,872,500 for mid-kiln firing on three long dry kilns (with all project costs included except controls programming). Reference 7 lists total capital costs in the range of \$391,000 to \$707,000 for a mid-kiln firing conversion, generally more consistent with the values of Reference 22 than Reference 21. Finally, case study CK-3 (Blue Circle Cement, Atlanta, Georgia) indicates a total capital cost of \$1,495,000 for two 950 tons per day (tpd) or 40 tph kilns, with fixed O&M increasing by \$64,000/yr and a decrease of variable O&M costs of over \$900,000 through reduced fuel costs. For this analysis, economics similar to those of case study CK-3 are assumed.

It is important to note that this analysis assumes that mid-kiln tire injection will run year-round, even under circumstances where only seasonal controls are needed. This makes sense because the technology has economic benefits when in use and a user would not be motivated to turn it off outside of the ozone season. As in the previous analysis, impact on facility production was not considered. The results of the analysis are shown in Tables III-30a through c, showing that there are potentially significant economic benefits of this technology, in addition to the small environmental benefit of lower NO_x emissions. Because the economic benefits of the mid-kiln firing technology are substantial, the cement industry has adopted it even in the absence of any explicit regulatory requirements.

CemStarSM

Case Study CK-2 (Texas Industries, Inc., Midlothian, Texas) reported that the capital cost for retrofitting CemStarSM on each of its four 40 ton/hr wet process kilns was \$250,000. In addition to this capital cost is an operating cost (a license fee) equal to about \$16/ton of steel slag added to the process. At a plant of similar size to the Midlothian plant, a 3.3 tph slag addition would result in roughly an additional \$53/hour for the operating cost of each kiln (\$211/hr total for four kilns). Since the reduction in fuel cost expected from using CemStarSM is application-specific, it is not included in this cost analysis. Incremental clinker revenues are valued at an approximate level of \$15 to \$50 per ton of additional clinker produced.²³ Net clinker value equals about \$15-\$50 per ton after expenses (production cost, sales cost, transportation, etc.). These amounts will vary from one facility to another and with market conditions.

Table III-30a: Cost Effectiveness of Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton Clinker on Two 40 Ton/hr Kilns			
Time Period of Control and Units of Cost	no tipping fee. ^x		
	<i>Capacity Factor</i>		
	0.45	0.65	0.85
Seasonal, \$/ton NO _x	(\$2,326)	(\$3,444)	(\$4,035)
Seasonal, \$/ton clinker	(\$0.48)	(\$0.72)	(\$0.84)
Annual, \$/ton NO _x	(\$969)	(\$1,435)	(\$1,681)
Annual, \$/ton clinker	(\$0.48)	(\$0.72)	(\$0.84)

Table III-30b: Cost Effectiveness of Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton Clinker on Two 40 Ton/hr Kilns

\$20/ton tipping fee.

Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, \$/ton NOx	(\$5,164)	(\$6,281)	(\$6,873)
Seasonal, \$/ton clinker	(\$1.08)	(\$1.31)	(\$1.43)
Annual, \$/ton NOx	(\$2,151)	(\$2,617)	(\$2,864)
Annual, \$/ton clinker	(\$1.08)	(\$1.31)	(\$1.43)

Table III-30c: Cost Effectiveness of Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton Clinker on Two 40 TPH Kilns

\$75/ton tipping fee.

Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, \$/ton NOx	(\$12,966)	(\$14,084)	(\$14,675)
Seasonal, \$/ton clinker	(\$2.70)	(\$2.93)	(\$3.06)
Annual, \$/ton NOx	(\$5,403)	(\$5,868)	(\$6,115)
Annual, \$/ton clinker	(\$2.70)	(\$2.93)	(\$3.06)

Tables III-31 a, b, and c show the results of cost effectiveness calculations for four wet-process kilns equipped with CemStar for three different net clinker values (in dollars per ton). Three control scenarios are considered for each case: 1) annual NOx control and annual operation (steel slag is added year-round to achieve year-round NOx reductions); 2) seasonal NOx control and annual operation (steel slag is added year round, but only ozone season NOx reduction counts); and 3) seasonal NOx control and seasonal operation (steel slag is added only during the ozone season).

The calculations performed to produce the results in Table III-31a assume that the incremental clinker production is worth slightly less than the incremental license fee, evaluating the situation where NOx reduction is the only reason to use the CemStar technology. This is an unusual case since most facilities will benefit from increased production, even after the cost of the license fee (\$16/ton) is considered. Even in this case, cost of controlling NOx is well below \$1000/ton. Tables III-31 b and c show cases where the value of the incremental production exceeds the value of the license fee, as should be the case when this technology is applied. In these cases (\$30/ton and \$50/ton of net clinker, respectively), the CemStar technology produces net economic benefits in addition to the NOx reductions provided. Over twenty kilns in the U.S. have used this technology.

Because of the economic benefits of this technology, the seasonal control and annual operation scenario is more realistic than the seasonal control and seasonal operation scenario.

There is a significant cost trend indicated in the tables. The cost of using CemStar to reduce NOx (\$/ton) decreases as usage increases, as would be expected. However, the decrease is slight, reflecting the relatively low capital cost and "pay as you go" nature of this technology. The results shown in Tables III-31b and III-31c show a net economic benefit in using the technology.

F.2 Cost Effectiveness of Secondary Methods of Controlling NOx from Cement Kilns

Selective Non-Catalytic Reduction (SNCR)

There are currently no commercial applications of SNCR on cement kilns in the U.S. However, some information from case studies and from estimates from vendors who have supplied commercial systems overseas provide data to estimate the cost of NOx reduction. In Reference ²⁴, the capital cost of employing urea SNCR on a precalciner kiln is estimated to be \$0.08/ton of clinker, estimated on a 15-year life with the plant operating at 85% capacity. This equates to nearly \$900,000 for a 100 tph kiln. This would scale to \$1.35 million for a 150 tph kiln, but since scaling is probably not linear with size, this is probably a conservative estimate. It is approximately consistent with information in Reference 7 and information from a supplier described in Table III-32.²⁵

Using the capital cost of about \$1.35 million (including all associated project costs such as installation, site preparation, project management, etc.) for a 150 ton/hr kiln and a 45% NOx reduction from 700 lb/hr to 385 lb/hr, cost effectiveness was calculated (see Table III-33).

Costs in Table III-33 are shown in both \$/ton of NOx reduced and \$/ton of clinker produced. This is because the kiln operators are interested in the cost impact to the product. Moreover, the kiln operators may choose to apply technology to those kilns where the impact to the cost of product is minimum. Alternatively, operators may choose to preferentially operate those kilns where the impact of the cost of NOx control on the product cost is least.

Table III-31a: Cost Effectiveness of CemStar - 20% Reduction from 200 lb NOx/hr/kiln (800 pph total) on Four 40-Ton/hr Wet Process Kilns, Net Clinker Value = \$15/ton			
Time Period of Control and Operation	Capacity Factor		
	0.45	0.65	0.85
Seasonal Control and Operation (\$/ton NOx)	\$1,120	\$822	\$664
Seasonal Control and Operation (\$/ton clinker)	\$0.23	\$0.17	\$0.14
Seasonal Control/Annual Operation (\$/ton NOx)	\$1,332	\$1,034	\$877
Seasonal Control/Annual Operation (\$/ton clinker)	\$0.28	\$0.22	\$0.18
Annual Control (\$/ton NOx)	\$555	\$431	\$365
Annual Control (\$/ton clinker)	\$0.28	\$0.22	\$0.18

Table III-31b: Cost Effectiveness of CemStar - 20% Reduction from 200 lb NOx/hr/kiln (800 pph total) on Four 40-Ton/hr Wet Process Kilns, Net Clinker Value = \$30/ton			
Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal Control and Operation (\$/ton NOx)	(\$1,156)	(\$1,454)	(\$1,611)
Seasonal Control and Operation (\$/ton clinker)	(\$0.24)	(\$0.30)	(\$0.34)
Seasonal Control/Annual Operation (\$/ton NOx)	(\$4,129)	(\$4,427)	(\$4,585)
Seasonal Control/Annual Operation (\$/ton clinker)	(\$0.86)	(\$0.92)	(\$0.96)
Annual Control (\$/ton NOx)	(\$1,721)	(\$1,845)	(\$1,910)
Annual Control (\$/ton clinker)	(\$0.86)	(\$0.92)	(\$0.96)

Table III-31c: Cost Effectiveness of CemStar - 20% Reduction from 200 lb NOx/hr/kiln (800 pph total) on Four 40-Ton/hr Wet Process Kilns, Net Clinker Value = \$50/ton

Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal Control and Operation (\$/ton NOx)	(\$4,190)	(\$4,488)	(\$4,646)
Seasonal Control and Operation (\$/ton clinker)	(\$0.87)	(\$0.94)	(\$0.97)
Seasonal Control/Annual Operation (\$/ton NOx)	(\$11,412)	(\$11,710)	(\$11,868)
Seasonal Control/Annual Operation (\$/ton clinker)	(\$2.38)	(\$2.44)	(\$2.47)
Annual Control (\$/ton NOx)	(\$4,755)	(\$4,879)	(\$4,945)
Annual Control (\$/ton clinker)	(\$2.38)	(\$2.44)	(\$2.47)

For those cement kiln applications where SNCR is technically feasible, NOx reductions below \$1,000/ton of NOx are achievable. Also, as demonstrated by the results in the table, the impact of SNCR on the cost of the product is reduced under a seasonal scenario.

Table III-32: Reported Approximate Capital Cost for Urea SNCR System on a Precalciner Kiln²⁵

Kiln size	< 150 ton/hr
NOx Baseline	> 500 ppm @ 10% O2
NOx Reduction	30 - 50%
Heat Input Ratio	40:60 to 50:50
Temp @ Calciner Injection Point	850 deg C or higher
Equipment and Engineering Costs, <i>excluding installation and area preparation, etc.</i>	\$400,000 - \$800,000

Table III-33: Cost Effectiveness of SNCR on 150 Ton/hr Precalciner Kiln, 45% NOx Reduction (from 700 lb/hr to 385 lb/hr)

Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, \$/ton NOx	\$1,215	\$1,000	\$890
Seasonal, \$/ton clinker	\$0.53	\$0.44	\$0.39
Annual, \$/ton NOx	\$810	\$725	\$675
Annual, \$/ton clinker	\$0.85	\$0.76	\$0.71

Biosolids Injection (BSI)

Biosolids injection is being used at the Mitsubishi Cement facility in Lucerne Valley, CA. The facility has a clinker capacity of 221 tons per hour without biosolids injection, but the use of the

technology will typically reduce capacity slightly, due to the increased volume of gas from the moisture in the biosolids. At this facility, the capacity is reduced to 185 tph, a 16% reduction. The capital cost of the technology has been published at \$371,000 for the Lucerne Valley facility, including all site work, equipment, etc. The operating costs for a facility similar to Mitsubishi's cover a wide range, from a cost of nearly \$150,000 to a net *revenue stream* of \$1,350,000 per year. This is explained by the potential for a tipping fee for receiving the biosolids, which can be worth up to about \$1.5 million. Not included in these operating costs are the costs of increased fan power, incremental fuel cost, cost of lost revenue from reduced clinker production or additional license fees that may be required. Despite reduced clinker production, fuel costs increase because of the additional heat necessary to evaporate the moisture in the biosolids. Without including the value of lost clinker revenues, tipping fees for receiving biosolids, or license fees, Mitsubishi Cement estimated that the cost effectiveness of using biosolids injection in the range of \$108/ton to \$1,775/ton of NOx reduced for a plant operated at near 90% capacity and NOx reduction year-round.²⁶

The economic viability of biosolids injection as a NOx reduction technique is driven largely by the ability to negotiate a contract for receiving the biosolids while being paid a tipping fee. It should be noted that biosolids injection may not be applicable to many kilns. First, kilns must have the proper temperature window for an SNCR reaction, limiting this technology to precalciner kilns. Second, the kiln must have sufficient available fan capacity to support biosolids injection without too much of a decrease in clinker capacity. This is very limiting because most kilns operate near maximum capacity. Under just the right set of circumstances, biosolids injection can be an economically attractive approach for reducing NOx emissions. Because the economics and applicability of this process are so strongly dependent on several variables that could vary widely, additional modeling for cost effectiveness was not performed.

G. Summary

This chapter evaluated a number of technologies for their cost effectiveness that have been commercially applied to reduce NOx emissions under scenarios that are expected to be of interest to existing sources. The costs of these technologies were determined from publicly available data, information provided by technology suppliers, and from information provided by the technology users. An extremely important part of this report is the final chapter (Chapter IV), in which the detailed information related to cost and operating experience from actual technology users is provided in the form of case studies. Incorporating the user-provided operating and cost data from these case studies into the cost analysis just presented provides robust and reliable estimates of cost effectiveness that are strongly anchored in reality.

H. References

- ¹ NESCAUM-MARAMA, Status Report on NO_x: Control Technologies and Cost Effectiveness for Utility Boilers, June 1998.
- ² Reilly and Brown, Investment Analysis and Portfolio Management, The Dryden Press, 1997: pp 16-18.
- ³ The Wall Street Journal, 23 June 1999.
- ⁴ Brigham and Houston, Fundamentals of Financial Management, 8th ed., The Dryden Press, 1998.
- ⁵ U.S. Environmental Protection Agency. "Alternative Control Techniques Document – NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers." EPA-453/R-94-022, March 1994.
- ⁶ U.S. Environmental Protection Agency. "Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines," EPA-453/R-93-007, January 1993.
- ⁷ U.S. Environmental Protection Agency. "Alternative Control Techniques Document – NO_x Emissions from Cement Manufacturing." EPA-453/R-94-004, March 1994.
- ⁸ Mike Knenlein of Fuel Tech. Letter to the author. August 25, 1999.
- ⁹ Doug Henneghan of Norton Catalytic Products. Personal Communication. 18 September 1999.
- ¹⁰ Sommerlad, R.E. and Pratas, J.M. "Fas-Based Technologies – An Update on Development and Commercialization." Ninth Annual NO_x Control Conference, Council of Industrial Boiler Owners. Hartford, CT: March 11-12, 1996.
- ¹¹ Onsite Sycom Energy Corporation. "Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines." Performed for U.S. Department of Energy, Contract No. DE-FC02-97CHIO877. October 15, 1999.
- ¹² Leslie Witherspoon of Solar Turbines. Letter to the author. August 26, 1999.
- ¹³ Alex Huhmann of PSE&G. Personal communication. December 6, 1999.
- ¹⁴ Ken Burns of Engelhard. Personal communication. September 3, 1999.
- ¹⁵ Mike Gregory of Peerless Manufacturing Company. Letter to the author. November 16, 1999.
- ¹⁶ Electric Power Research Institute. "Gas Turbine Selective Catalytic Reduction Procurement Guidelines." EPRI GS-7254, Project 2936-1 May, 1991.
- ¹⁷ U.S. Environmental Protection Agency. "Alternative Control Techniques Document – NO_x Emissions from Stationary Reciprocating Internal Combustion Engines." EPA-453/R-93-032, July, 1993.
- ¹⁸ State of California Air Resources Board. "CAPCOA/ARB Proposed Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Internal Combustion Engines (DRAFT)." December 3, 1997.
- ¹⁹ Schrama, H., Blumenthal, M., and Watherhead, E. C. "A Survey of Tire Burning Technology for the Cement Industry." IEEE Cement Industry Technical Conference. San Juan, Puerto Rico: June 4-9, 1995.

²⁰ Waste News Online. Prices for recycled goods for the week ending October 15, 1999.

²¹ Portland Cement Association. "Report on NO_x Formation and Variability in Portland Cement Kiln Systems – Potential Control Techniques and Their Feasibility and Cost Effectiveness." PCA R&D Serial No. 2227, 1999.

²² Gregory Schwall of TMI Systems. Letter to Ann Dougherty of Portland Cement Association. October 30, 1998.

²³ Greg Mayes of Texas Industries. Letter to the author. January 17, 2000.

²⁴ Steuch, H.E., Hille, J., Sun, W.H., Bisnett, M.J., and Kirk, D.W. "Reduction of NO_x Emissions from a Dry Process Preheater Kiln with Calciner Through the Use of the NO_xOUT Process." Fall Meeting of the General Technical Committee of the Portland Cement Association. Seattle, WA: September 18-24, 1994.

²⁵ Michael J Knenlein of Fuel Tech, Inc. Letter to the author. August 9, 1999.

²⁶ Biggs, H.O. "BioSolids Injection Technology: An Innovation in Cement Kiln NO_x Control." Thirty-first International Cement Seminar. TP881.I5, 1995.

IV. Case Studies

A. Introduction

The purpose of the case studies is to provide information from the actual technology users on their experience (both operating and cost) with the control technologies addressed in the report. The information was gathered and the case studies were prepared in a manner designed to ensure that the end-user's perspective was maintained.

The case studies were performed in cooperation with the facility owners. In each case the facility owners filled out a questionnaire that was designed for their particular facility type. With the information gathered from the owners, a case study was prepared and then sent to the facility owners for review and comment. After the facility owners had reviewed the case study and revisions were made in accordance with their comments, the facility owners reviewed the revised case study for the final approval. After these steps the final version of the case study was included in this report. Every case study presented in this report went through this procedure.

A note on Cost Effectiveness - During this study it became apparent that only a few of the owners of these facilities had performed calculations to estimate cost effectiveness, measured in terms of dollars per ton of NO_x removed (\$/ton). This may change in the future if market-based approaches, such as “cap and trade” approach, are introduced to meet regulatory requirements for these non-utility sources. Under such an approach, facilities will have an incentive to estimate accurately the cost effectiveness of strategies and technologies under consideration, since they will be able to trade (buy and sell) emission allowances with other sources with different incremental costs for control.

In the gas turbine and IC engine case studies from gas transmission companies (Duke Energy and Tennessee Natural Gas), cost effectiveness calculations were provided by them using a format that the gas transmission industry has devised.

Although cost effectiveness (in \$/ton of NO_x removed) was estimated by only a few users, all case study participants did provide extremely useful information on capital cost and operating cost- the key pieces of information necessary to estimate cost effectiveness. This information, which for many of these source categories has not been publicly available directly from users until this report, is extremely important for making an accurate assessment of technology costs. These key pieces of information were used where appropriate in Chapter III to provide robust and reliable cost effectiveness estimates that are “anchored in reality.”

An effort was made to have a consistent format among case studies in this chapter. However, because each case study represents a unique situation prepared with the user's assistance, formats for case studies vary somewhat to accommodate the type and amount of information provided by the case study participants.

B. Industrial Boiler Case Studies

B.1 Case Study BLR-1, Minergy Corp, Neenah, Wisconsin

Operator Contact - Tom Baudhuin

Background and Technology Selection

Minergy Corporation operates a facility in Neenah, WI. In 1997 Minergy added a boiler for generation of steam for facility use.

General Statistics on Minergy Boiler	
MMBTU/hr	350
Boiler age (yrs)	1.5
Boiler type	Cyclone
Air heater	Tubular
Fuel(s)	Natural Gas and 4000 BTU/lb Paper Sludge
Baseline (uncontrolled) NO _x	0.65 lb/MMBTU
Controlled NO _x	0.30 lb/MMBTU

As a new source, the facility was subject to New Source Review Regulations and was required to install Best Available Control Technology (BACT). For this type of facility BACT was determined to require addition of Selective Non-Catalytic Reduction (SNCR) technology for control of NO_x emissions. Minergy selected urea-based SNCR, or NO_xOUT[®].

Project Execution

The SNCR system was installed as part of a larger project. Therefore, it is not possible to determine the schedule for the SNCR system alone.

Experience

The operating experience from commissioning through to June 1999 is outlined on the table that follows. Notably, the system met its guaranteed NO_x reduction levels and ammonia slip levels. Despite reported ammonia slip of 25 ppm, ammonium bisulfate salt deposition on the air heater has not been a problem. There has not been any noticeable ammonia odor in the fly ash or any disposal problems for ash due to ammonia. The system has been reliable in reducing NO_x emissions. On two occasions the boiler required shutdown for repair of tube leaks believed to be due to impingement of urea droplets. Minergy is reviewing this matter with the technology supplier along with their practices for operating and maintaining the urea injectors.

Since the SNCR system was supplied with the boiler, it is uncertain what impact the SNCR system has on boiler efficiency or parasitic loads.

Experience and Performance	
Months in operation (June '99)	18
# Forced outage incidents	2
Lost boiler-operating hrs.	200
Increased parasitic loads	Unknown
Change in boiler efficiency	Unknown
Reagent Consumption	30 gph
Reagent Consumption guarantee met?	Yes
NH₃ slip guarantee, ppm	50
NH₃ slip actual, ppm	25
Air heater washing/deposition?	No
Visible Plume/year	No

Cost Effectiveness

Minergy was unable to provide detailed information regarding the cost of controlling NO_x emissions with SNCR at this facility. The approximate cost of the process equipment and associated engineering and startup services was between \$500,000 and \$750,000. The cost of installation was not separated out since the SNCR system was provided as part of a larger program.

B.2 Case Study BLR-2, International Paper, Jay, Maine

Operator Contact - Peter Lee

Background and Technology Selection

International Paper operates a paper mill in Jay, Maine. At the facility there are two wall-fired boilers that fire No. 6 fuel oil and generate 450 million pounds per hour (pph) of steam. The boilers operate from 25% to 100% of full steam production rates.

General Statistics on International Paper Boilers	
MMBTU/hr	680 each (x 2)
Steam Generation (million pph)	450 each (x 2)
Operating range	25%-100% of full steaming rate
Boiler age (yrs)	34
Boiler type	Wall
Year that NO_x reduction system was placed in service	1995
Fuel(s)	No. 6 Fuel Oil
Fuel Nitrogen Content	0.461%
Baseline (uncontrolled) NO_x	0.427 lb/MMBTU

In 1995, the facility implemented Low NO_x Burner modifications in order to reduce NO_x emissions to meet Maine's NO_x RACT requirements. The modifications entailed upgrading of existing burner hardware such as swirlers, nozzles, etc., and optimization of the operation of that equipment.

Project Execution

The burner modifications were made with minimal impact to boiler operation.

Experience

The operating experience from commissioning through to September 1999 is outlined on the table that follows. Notably, the program met its guaranteed NO_x reduction level of 0.40 lb/MMBTU, and actual NO_x emissions are about 0.38 lb/MMBTU. There have not been any increases on opacity or particle matter or CO emissions. The burner modifications have not had any adverse impact on boiler performance or reliability.

Experience and Performance	
Months in operation (Sept '99)	48
# Forced outage incidents	0
Lost boiler-operating hrs.	0
Increased parasitic loads	None
Change in boiler efficiency	None
Adverse changes to CO, PM emissions or opacity?	None
Changes in boiler reliability?	None
NO_x Guarantee	0.40 lb/MMBTU
NO_x guarantee met?	Yes
Actual NO_x	0.38 lb/MMBTU

Cost Effectiveness

International Paper performed this program for a total installed cost of about \$30,000. They have not performed a detailed cost estimate of the project.

B.3 Case Study BLR-3, Chevron Process Heater Equipped with SCR, El Segundo, California

Operator Contact - Jim Seebold (510) 242-3313

Background and Technology Selection

Chevron operates a refinery in El Segundo, CA. The facility, which is close to Los Angeles, is subject to the strict air pollution control requirements of the South Coast Air Quality Management District and the California Air Resources Board. In 1991, Chevron was required to reduce NO_x emissions from its fired heaters, including two furnaces that are floor fired and burn refinery fuel gas. The furnaces were originally equipped with combustion NO_x controls that maintained NO_x at about 40-50 ppm. The combined rated capacity of the two furnaces is 68 MMBTU/hr.

They selected SCR with a low-temperature catalyst due to the lower cost of this technical approach. Aqueous ammonia is used as the reagent for the SCR, and the catalyst is a low-temperature catalyst that is capable of operation at temperatures of 325 F to 650 F. In this case, the operating temperature is about 420 F. The use of a low-temperature catalyst enabled use of SCR with fewer plant modifications and less impact on heater operation than if a conventional SCR catalyst were used. An SCR using conventional SCR catalyst would have entailed a capital cost of roughly 50% more due to the modifications that would have been necessary to fit the catalyst.

General Statistics on Chevron Process Heaters	
MMBTU/hr	34 x 2 (68 total)
Heater Type	Floor Fired
Year that NO_x reduction system was placed in service	1991
Fuel(s)	Refinery Fuel Gas
Baseline (uncontrolled) NO_x	40-50 ppm
Controlled NO_x	<9 ppm

Project Execution

Total system capital cost was \$1.5 million. The project schedule was as follows:

Project Schedule and Cost	
Preparation of Bid Package	4 weeks
Evaluation of Proposals	4 weeks
Award of Contract (AOC) to completion of engineering	8-10 weeks
AOC to delivery of equipment	40-45 weeks
AOC to completion of installation	50 weeks
AOC to completion of system commissioning	52 weeks
Project Cost	\$1.5 million

Experience

The operating experience from commissioning through to September 1999 is outlined on the table that follows. The program met its guaranteed NO_x reduction level of 9 ppm, or about 0.01 lb/MMBTU with ammonia slip at undetectable levels. In the eight years of operation of the system, the permitted NO_x emissions level has been exceeded four times. The \$35,000 value for levelized catalyst cost includes a provision for disposal of the used catalyst as well as the cost of replacement catalyst. The total variable O&M, which includes the catalyst, ammonia and other minor costs, is \$41,000.

For most boiler applications NO₂ comprises only a small portion of the total NO_x. It is notable that due to the high excess air levels and, consequently, the high NO₂ content of the gas stream from this heater, the molar ratio of ammonia to NO_x reduced is greater than the expected 1:1 that is common for most boilers. It actually approaches 2:1.

Experience and Performance	
Time in operation (Sept '99)	8 years
# Forced outage incidents	1
Lost heater-operating hrs.	0
# NOx exceedances	4
Increased parasitic loads	75 KW
Change in heater efficiency	None
Adverse changes to CO, PM emissions or opacity?	None
Changes in boiler reliability?	None
NOx Guarantee	9 ppm
NOx guarantee met?	Yes
Actual Controlled NOx	< 9 ppm, or < 0.01 lb/MMBTU
Ammonia slip guarantee	<20 ppm
Measured slip	None detected
Catalyst lifetime guarantee	3 yrs
Catalyst volume	5.1 m3
Levelized catalyst replacement cost	\$35,000
Total variable O&M charges for year (includes levelized catalyst, ammonia, etc.)	\$41,000
Additional man-hours per week	4

Cost Effectiveness

A detailed, cost effectiveness analysis to determine the \$/ton of NOx reduced was not provided. However, using the data above with some assumptions, a determination of cost effectiveness could be made.

B.4 Case Study BLR-4, Sauder Woodworking, Archbold, Ohio

Operator Contact - Thomas Brodbeck (419) 446-3547

Background and Technology Selection

Sauder Woodworking operates a wall-fired, 57 MMBTU/hr boiler that fires wood waste. The facility was installed new in 1994 and was therefore subject to New Source Review (NSR) regulations, which imposes strict controls on new sources of NOx. Sauder was, therefore, required to control NOx to 0.20 lb/MMBTU and install Selective Catalytic Reduction technology.

The uncontrolled baseline NOx level into the SCR was not provided. The controlled NOx, however, is 0.20 lb/MMBTU.

General Statistics on Sauder Boiler	
MMBTU/hr	57
Boiler Type	Wall Fired
Age of Boiler	5 years (since 1994)
Year that NO_x reduction system was placed in service	1994
Fuel(s)	Wood
Baseline (uncontrolled) NO_x	Not Available
Controlled NO_x	0.20 lb/MMBTU

Project Execution

The SCR system was provided as a part of a new boiler facility. Therefore, it was a part of a much larger project. The cost of the SCR catalyst, reactor, controls, ammonia injection grid, and associated engineering to the boiler supplier is reported by the catalyst supplier (Norton) to be \$450,000. However, additional costs were incurred in installing the equipment and supply of the ammonia storage tank. So the total cost associated with SCR was greater than \$450,000.

Experience

The 72 months of operating experience from commissioning through to September 1999 have demonstrated that the equipment has met its NO_x reduction objective of 0.20 lb/MMBTU. This experience is summarized in the table that follows. The catalyst appears to be performing as expected. The system has never caused the facility to lose operating hours. The SCR exit NO_x analyzer sampling system has required some periodic attention (four times in the six years). Deposits sometimes form on the sample line, causing erroneous indications.

Cost Effectiveness

A detailed, cost effectiveness analysis to determine the \$/ton of NO_x reduced was not performed by Sauder Woodworking.

Experience and Performance	
Months in Operation (as of Sept '99)	72 months
# Forced outage incidents	0
Lost operating hrs.	0
# NO _x exceedances	0
Increased parasitic loads	Neg.
Change in efficiency	None
Adverse changes to CO, PM emissions or opacity?	None
Changes in boiler reliability?	None
NO _x Guarantee	0.20 lb/MMBTU
NO _x guarantee met?	Yes
Actual Controlled NO _x	<0.20 lb/MMBTU
Ammonia slip guarantee	<20 ppm
Measured slip	None detected
Catalyst lifetime guarantee	2 yrs
Catalyst performing as expected	Yes
Levelized catalyst replacement Cost	\$25,000
Additional Man Hours per week	5

B.5 Case Study BLR-5, Michigan State University, TB Simon Power Plant, Unit #4, East Lansing, Michigan

Operator Contact - Bob Ellerhorst

Background and Technology Selection

The Michigan State University in East Lansing, MI, operates a power plant providing energy to the campus. In 1991 it added a new circulating fluidized bed (CFB) boiler that fires coal. The boiler, rated at 380 MMBTU/hr, was required under Michigan New Source Review regulations to install a Selective Non-Catalytic NO_x Reduction system using aqueous urea solution as the reagent. The baseline uncontrolled level of NO_x was not provided.

General Statistics on Michigan State Boiler	
MMBTU/hr	380
Boiler age (yrs)	8
Boiler type	Circulating Fluidized Bed
Air heater	Tubular
Fuel(s)	Coal
Baseline (uncontrolled) NO _x	Not Available
Maximum Controlled NO _x	0.16 lb/MMBTU

Project Execution

The SNCR system was installed as a part of a much larger project to install the boiler.

Experience

The operating experience from commissioning through to September 1999 is outlined in the table that follows. Notably, the system met its guaranteed NO_x reduction levels and ammonia slip levels. Ammonium bisulfate salt deposition on the air heater has not been a problem. There has not been any noticeable ammonia odor in the fly ash or any disposal problems for ash due to ammonia. The system has met the guarantee level and there have been no occasions when the urea SNCR system has failed to provide the expected performance.

Although the system has been relatively reliable, causing no forced outages or lost operating hours, there have been occasional mechanical problems in the form of injector plugging, metering pump failures, flow meter fouling, and stainless steel pipe leaks. Therefore, periodic maintenance and repair have been needed. There is sufficient redundancy in the system that mechanical failures have never taken the system out of service.

Since the SNCR system was supplied with the boiler, it is uncertain what impact the SNCR system has on boiler efficiency or parasitic loads.

Experience and Performance	
Months in operation (Sept. '99)	84
Guaranteed NO_x	0.16 lb/MMBTU
Controlled NO_x	0.14 lb/MMBTU
# NO_x exceedances attributable to SNCR system failure	0
# Forced outage incidents attributable to SNCR system	0
Lost boiler-operating hrs. attributable to SNCR system	0
Increased parasitic loads	Negligible
Change in boiler efficiency	Negligible
NH₃ slip guarantee, ppm	< 18
NH₃ slip actual, ppm	0.75
Air heater washing/deposition?	No
Visible Plume/year	No
Extra Man-Hours/week for O&M	2

Cost Effectiveness

Michigan State's TB Simon Power Plant was unable to provide detailed information regarding the cost of controlling NO_x with SNCR at this facility. The boiler and SNCR system were purchased together. Information identifying the specific cost of the SNCR system versus the boiler is not, therefore, available.

B.6 Case Study BLR-6, Temple Inland Corp. Shippenville, Pennsylvania

Operator Contact - Ted Peters, Temple Inland Corp., (814) 226-8961

Background and Technology Selection

Temple Inland Corporation manufactures medium density fiberboard (MDF) and other wood products. In 1996 they added a 155 MMBTU/hr bubbling bed boiler to provide process heat for the facility. The new boiler is fired with MDF waste and hog fuel (wood waste). Temple Inland is required to control NO_x emissions on the boiler to below 0.17 lb/MMBTU. Since the boiler has a baseline emission of 0.40 lb/MMBTU without secondary controls, additional controls were needed. SNCR was chosen as the preferred technical approach and urea was selected as the reagent because urea is used on site for other purposes.

General Statistics on Temple Inland	
MMBTU/hr	155
Boiler age (yrs)	3.5
Year that NO_x reduction system was placed in service	1997
Boiler type	Bubbling Bed
Fuel(s)	MDF Waste
Baseline (uncontrolled) NO_x	0.40 lb/MMBTU
Controlled NO_x	Under 0.17 lb/MMBTU

Project Execution

The SNCR system was installed as part of a much larger project to install the boiler. So, it is not possible to determine precisely the schedule for the SNCR system. However, the following schedule was provided as being approximately the schedule for SNCR. Of course, the entire project schedule was longer since much more equipment was provided.

The total project took 32 weeks after award of contract. Total contract cost was \$225,000 for the process equipment, license, controls, etc. Project management, purchasing and other indirect costs were about \$8,500, and commissioning and testing costs were \$6,500.

Project Schedule (Approximate, SNCR only)	
Task	Time, weeks
Preparation of Bid Package	3
Evaluation of Proposals	2
Award of Contract (AOC) to completion of engineering	10
AOC to arrival of equipment on site	26
AOC to completion of installation	30
AOC to completion of system commissioning	32

Project Costs	
Cost for equipment and engineering	\$225,000
Commissioning and testing	\$6,500
Other indirect costs	\$8,500
Total	\$240,000

Experience

The operating experience from commissioning through to October 1999 is outlined in the table that follows. Notably, the system met its guaranteed NO_x reduction levels and ammonia slip levels. Experience with the reliability of the system has been mixed. Although the pumping and control systems have been highly reliable, the reagent distribution and injection system was initially prone to plugging throughout. The system, therefore, required continual attention to keep it operating. The plugging is believed by Temple Inland to be associated with a chemical reaction between the urea and impurities in the reagent and/or dilution water. For reasons of cost control and availability, Temple Inland does not use the technology supplier's licensed reagent, but a locally-available urea product that is also used on site for other purposes. Temple Inland modified the SNCR system to mitigate the plugging problem, and the modifications were successful at mitigating the plugging to a more manageable level. Labor necessary to service the system is now less than the initial experience.

Experience and Performance	
Months in operation (Oct '99)	41
Guaranteed NO_x	0.17 lb/MMBTU
Actual controlled NO_x	0.13 lb/MMBTU
Lost boiler-operating hrs. attributable to SNCR system	None
NH₃ slip guarantee, ppm	< 15
NH₃ slip actual, ppm	5
Aqueous Urea Solution Use (30% by wt.)	160 pph
Extra Man-Hours/week for O&M	4-40

Cost Effectiveness

Temple Inland has not performed a detailed analysis of cost effectiveness in terms of dollars per ton of NO_x removed.

B.7 Case Study BLR-7, Fort James Corporation, Green Bay, Wisconsin

Environmental Contact - Timothy Mattson, Fort James Corp., (920) 438-2191

Engineering Contact- Kim Dohm, Fort James Corporation, (920) 438-2644

Background and Technology Selection

The Fort James Corporation commissioned a new refractory-lined Bubbling Bed combustor with a waste heat boiler at the end of 1998. The boiler fires paper sludge at a rate of about 250 dry tons per day. Fort James was required to install an SNCR system to reduce NO_x to below 100 ppm, or 50% removal, whichever is less stringent. SNCR using aqueous ammonia reagent (19% by wt.) was selected.

General Statistics on Fort James Boiler	
Max. Steam Load	57,000 #/hr @ 180 psig
Boiler age (yrs)	1
Combustor type	Bubbling Bed
Fuel(s)	Paper Sludge and natural gas
Baseline (uncontrolled) NO_x	Approx. 250 ppm
Max. controlled NO_x	Approx. 75 ppm

Project Execution

The SNCR system was installed as a part of a much larger project to install the boiler. So, it is not possible to determine precisely the schedule for the SNCR system. However, the following schedule was provided by the vendor as being approximately the schedule for a stand-alone SNCR system. Of course, the entire project schedule was longer since much more equipment was provided.

Project Schedule (Approximate, SNCR only)	
Task	Time, weeks
Preparation of Bid Package	2
Award of Contract (AOC) to completion of engineering	6-8
AOC to arrival of equipment on site	14-20
AOC to completion of installation	18-24
AOC to completion of system commissioning	20-26

Experience

The operating experience from commissioning through to December 1999 is outlined in the table that follows. Notably, the system met its guaranteed NOx reduction level and ammonia slip level.

Experience and Performance	
Months in operation (December '99)	13
Guaranteed NOx	100 ppm
Controlled NOx	75 ppm
NH₃ slip guarantee, ppm	< 35
NH₃ slip actual, ppm	10
# NOx exceedances attributable to SNCR system failure	0
# Forced outage incidents attributable to SNCR system	0
Lost boiler-operating hrs. attributable to SNCR system	0
Increased parasitic loads	5.56 KW
Extra Man-Hours/week for O&M	1

Cost Effectiveness

Fort James was unable to provide detailed information regarding the cost of controlling NOx with SNCR at this facility. The boiler and SNCR system were purchased together. Information identifying the specific cost of the SNCR system versus the boiler is not available.

B.8 Case Study BLR-8: Eastman Kodak Boiler #15, Micronized Coal Reburn, Rochester, New York

Company Contact: Jim Entwistle (716) 477-3136

Background:

Eastman Kodak's world headquarters at Kodak Park in Rochester, NY has a large facility to provide steam, electricity and other utilities to the site. At the facility, Kodak has several coal-fired cyclone boilers. In an effort to reduce NOx emissions at the site, in 1995 Kodak agreed to reduce NOx emissions from two of the boilers at the site through technology demonstration programs. Based upon the results of these programs, Kodak would implement additional control technology on other boilers at the site. The presumptive emission limit imposed by the State of NY was 0.60 lb/MMBTU, or about a 52% reduction from baseline. Because of the nature of the boilers and the nature of Kodak's business, the options for controlling NOx from the boilers were extremely limited. Data on one of the boilers (boiler #15) is in the table below:

Kodak Park	Boiler #15
Total steam flow (K lbs/hr)	400
primary fuel	coal
furnace type	cyclone
MMBTU/hr	478
Approximate Age (yrs)	43
1998 Capacity Factor	90%
1997 Capacity Factor	83%
Projected Capacity Factor	94%
Baseline (uncontrolled) NOx	1.36 lb/MMBTU

Technology Selection:

Kodak could not use SNCR or SCR technology because even small amounts of ammonia on site could potentially have a major, adverse impact on Kodak's manufacturing operations. Boiler #15 does not have gas available to it. The nearest gas line is about 2 miles away. The decision was made to pursue demonstration programs on boiler 15 (micronized coal reburn). Cofunding helped to reduce a significant portion of the capital cost of the program.

Project Execution:

The coal reburn project on Boiler #15 commenced at the end of 1995 and construction activities were completed in March of 1997.

The project for Boiler #15 was executed in accordance with the schedule on the following page. The program, which was partly funded by the Department of Energy to demonstrate micronized coal reburn technology, experienced an extended testing and acceptance program. The program was fast-tracked with an in-house team leading the effort.

Boiler #15 Project Schedule	
Preparation of bid package	0* weeks
Evaluation of proposals	0* weeks
In-house team formed to completion of engineering	37 weeks
In-house team formed to start of construction	32 weeks
In-house team formed to completion of installation	63 weeks
In-house team formed to system acceptance	149 weeks
Total weeks	149 weeks

** note: project was fast-tracked with overlapping activities*

Experience:

The micronized-coal reburn system on Boiler #15 operates commercially and has met all expectations with regard to operation. Details are described in the following table. Controlled NOx is a function of boiler load - NOx can be controlled to lower levels at full load than at low loads. Although Kodak reports that unburned carbon in the fly ash did increase significantly with the use of micronized coal reburning, which increased dust accumulation, it has not presented any problems with disposal. Kodak does not reinject fly ash, which is done with some cyclone boilers. Kodak accumulates fly ash in one place prior to disposal.

Boiler #15 Experience		
Controlled NOx (actual)	Load	Controlled NOx Emission
	400 K lb/hr steam	0.60 lb/MMBTU
	370 K lb/hr steam	0.72 lb/MMBTU
	340 K lb/hr steam	1.00 lb/MMBTU
CO emissions		<200 ppm
LOI (unburned carbon in fly ash)		Increased from 12% to 42%
Load Range of Reburn Operation		70%-100% of full load
Reburn Fuel Heat Input		17%
All guarantees met?		Yes
Months of operation		12
# Of times NOx exceeded limit due to reburn system		0
Outage incidents from NOx control		1
Estimated lost operating hours		90
Estimated additional maintenance needed		\$10,000/yr.
Additional man-hours per week		62
Any additional tube wastage due to reburning system?		none
Impact on boiler slagging?		None
Increase in parasitic loads		373 KW
Increased fuel cost		\$14/hr
Impact on boiler efficiency		-1.5%

Cost Effectiveness:

Kodak estimates the cost effectiveness to be \$1688/ton of NOx reduced. They used a capital recovery factor of 12% and a project lifetime of 15 years.

B.9 Case Study BLR-9: Eastman Kodak Boilers #41, 42, 43. Gas Reburn, Rochester, New York

Company Contact: Jim Entwistle (716) 477-3136

Background:

Eastman Kodak's world headquarters at Kodak Park in Rochester, NY has a large facility to provide steam, electricity and other utilities to the site. At the facility, Kodak has several coal-fired cyclone boilers. In an effort to reduce NOx emissions at the site, in 1995 Kodak agreed to reduce

NOx emissions from two of the boilers at the site, boilers #15 and #43, through technology demonstration programs. Based upon the results of these programs, Kodak would implement additional control technology on other boilers at the site. The presumptive emission limit imposed by the State of NY was 0.60 lb/MMBTU, or about a 52% reduction from baseline. Because of the nature of the boilers and the nature of Kodak's business, the options for controlling NOx from the boilers were extremely limited. Data on three of the boilers are in the table below:

Kodak Park	Boiler #41	Boiler #42	Boiler #43
Primary fuel	Coal	Coal	Coal
Furnace type	Cyclone	Cyclone	Cyclone
MMBTU/hr	500	500	640
Approximate Age (yrs)	35	31	30
1997 Capacity Factor	77%	77%	76%
1998 Capacity Factor	77%	79%	76%
Projected Capacity Factor	79%	78%	77%
Baseline (uncontrolled) NOx, lb/MMBTU	1.20	1.20	1.36

Technology Selection:

Boilers #41, 42, and 43 has gas readily available, while Boiler #15 does not. The decision was made to pursue demonstration programs on boilers 43 (gas reburn) and 15 (micronized coal reburn). After the successful demonstration of gas reburn on Boiler #43, Kodak made the decision to install gas reburning on boilers #41 and 42. Demonstration of the technology on Boiler #43 showed that flue gas recirculation was not necessary for these boilers. Therefore, the design of the Boiler #41 and #42 gas reburn systems differs significantly from the design of the gas reburn system on Boiler #43 in that flue gas recirculation is not used on the two systems for Boilers #41 and #42.

Project Execution:

The project on Boiler #43 was the first to be installed and was a demonstration program. The projects for Boilers #41, 42 and 43 proceeded according to the following schedules:

Boiler #43 Project Schedule	
Preparation of bid package	0* weeks
Evaluation of proposals	0* weeks
In-house team formed to completion of engineering	46 weeks
In-house team formed to arrival of equipment on site	46 weeks
In-house team formed to completion of installation	58 weeks
In-house team formed to completion of system commissioning	65 weeks
Total weeks (in service in 1996)	65 weeks

** note: project was fast-tracked with overlapping activities*

Boiler #41 Project Schedule	
Preparation of bid package	0* weeks
Evaluation of proposals	0* weeks
In-house team formed to completion of engineering	28 weeks
In-house team formed to arrival of equipment on site	35 weeks
In-house team formed to completion of installation	54 weeks
In-house team formed to completion of system commissioning	66 weeks
Total weeks (in service in 1999)	66 weeks

** note: project was fast-tracked with overlapping activities*

Boiler #42 Project Schedule	
Preparation of bid package	0* weeks
Evaluation of proposals	0* weeks
In-house team formed to completion of engineering	34 weeks
In-house team formed to arrival of equipment on site	22 weeks
In-house team formed to completion of installation	46 weeks
In-house team formed to completion of system commissioning	58 weeks
Total weeks (in service in 1998)	58 weeks

** note: project was fast-tracked with overlapping activities*

Experience:

The reburn systems on Boilers #43, 41, and 42 operate commercially and have met all expectations with regard to operation. Details are described in the table below.

Experience			
	Boiler #41	Boiler #42	Boiler #43
Year that NOx reduction system was placed in service	1999	1998	1996
Guaranteed NOx, lb/MMBTU	0.60	0.60	0.685
Actual controlled NOx, lb/MMBTU	0.60	0.60	0.60
CO emissions	<200 ppm	<200 ppm	<200 ppm
LOI	8%	10%	12%
Load range of reburn operation, % of full load	70%-100%	70%-100%	70%-100%
Reburn fuel heat input	13%	15.7%	20%
All guarantees met?	Yes	Yes	Yes
Months of operation	8	14	38
# of times NOx exceeded limit	0	0	0
Outage incidents from NOx control	0	0	0
Estimated lost operating hours	0	0	0
Estimated additional labor, man-hr/week	5	5	5
Estimated additional maintenance needed	Negligible	Negligible	Negligible
Increased fuel costs at full load?	\$117/hr	\$141/hr	\$230/hr
Any additional tube wastage?	No	No	No
Impact on slagging?	None	None	None
Increase in parasitic loads	0	0	56 KW
Impact on boiler efficiency	-0.20%	-0.23%	0.50%

As indicated in the table, the gas reburning has operated successfully without any failures for all three boilers.

Cost Effectiveness:

Kodak has estimated the cost effectiveness of the NOx reduction system using a capital recovery factor of 12% and a project economic life of 15 years. Cost effectiveness is estimated as follows:

Estimated Cost Effectiveness (\$/ton of NOx removed)		
Boiler 41	Boiler 42	Boiler 43
\$1,215	\$1,482	\$1,246

Actual costs experienced over the life of the facility will be dependent upon gas pricing and availability.

C. Gas Turbine Case Studies

C.1 Case Study GT-1, Duke Energy, Cromwell, Connecticut

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Cromwell, CT, are two Solar Centaur turbines that drive compressors. These simple-cycle gas turbines are rated at 4700 hp each.

The turbines were put in place before Connecticut's Reasonably Available Control Technology (RACT) requirements were in place. Therefore, it was necessary to reduce NOx emissions in 1995 when Connecticut RACT requirements took effect.

The units operate as needed to meet gas transmission demands.

The turbines were retrofitted with Dry Low NOx (DLN) Combustor technology was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was evaluated as the most cost-effective approach.

General Statistics on Duke Energy Cromwell, CT, Gas Turbine	
Turbine Type	Solar Centaur, simple-cycle compressor drive
HP	2 x 4700 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	T1 – 135 ppmvd at 15%O ₂ (permit) T2 – 110 ppmvd at 15%O ₂ (permit)
Controlled NOx	T1 & T2 - 42 ppmvd at 15%O ₂ (permit)

Project Execution

The technology was retrofitted onto the turbines in 1993, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was \$1.9 million. This price includes the cost of additional work on the compressors and reflects much more than the cost of the DLN retrofits alone. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1993 with the Dry Low NOx retrofits. During that time, the emissions of the turbines have been maintained under the required level and within the guarantee levels. In the roughly 72 months of operation, the NOx reduction system has resulted in

150 turbine outages and a total of 1,200 lost operating hours for both gas turbines at the facility. The shut downs and lost hours were due to frequent flameouts during weather changes that were not handled well by the first-generation of fuel controls. Duke Energy has since equipped the turbines with more modern electronic fuel controls from the manufacturer that have addressed this problem. Roughly two man-hours per week of additional service is needed to maintain the turbines.

The first generation combustor liner failed after about 5,000 hours. However, a new, third generation combustor liner appears to be operating properly for over 10,000 hours. The cost of replacing a combustor liner is roughly \$20,000, including labor and materials.

Experience and Performance	
Months in operation (as of Aug '99)	72
Increased parasitic loads	None
Change in turbine efficiency	None
Project Cost	\$950,000 per turbine (includes significant compressor work not related to DLN retrofit)
Estimated add'l fixed O&M	see Cost Effectiveness Calculations
Add'l man-hours of labor	2 hours/week per turbine
NOx guarantee, ppm	42 ppmvd at 15%O ₂
NOx guarantee met?	Yes
Combustor Life prior to DLN	20,000 + hours
Combustor Life after DLN	5,000 to 10,000 hours *
Number of forced outages	150*
Total lost operating hours	1200*
* New fuel controls have addressed the frequent forced outage problem that contributed to high lost operating hours. First-generation combustor liners failed after about 5,000 hours. New, third-generation combustor liner appears to have increased the combustor life to 10,000 hours or more.	

Cost Effectiveness

See attached cost effectiveness spreadsheets provided by Duke Energy.

Cromwell, CT Solar Centaur (T1) Dry Low NO_x Combustor Cost Effectiveness				
<u>Capital Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Total Capital Investment (TCI)	TCI	\$950,000	\$/turbine	Project Cost
Total Capital Costs		\$950,000	\$	Calculation
<u>Operating Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$30	\$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		\$3,120	\$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	\$468	\$/yr.	OAQPS
Total Operating Costs		\$3,588	\$/yr.	Calculation
<u>Maintenance Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$36	\$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		\$5,760	\$/yr.	Calculation
Material Cost	100% of Maintenance Cost	\$5,760	\$/yr.	OAQPS
Total Maintenance Costs		\$11,520	\$/yr.	Calculation
Total O&M Costs		\$15,108	\$/yr.	Calculation
<u>Indirect Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Overhead	60% of O&M Costs	\$9,065	\$/yr.	OAQPS
Administration	2% of TCI	\$19,000	\$/yr.	OAQPS
Insurance	1% of TCI	\$9,500	\$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	\$141,578	\$/yr.	OAQPS
Total Indirect Costs		\$179,143	\$/yr.	Calculation
Total Annual Costs	O&M Costs + Indirect Cost	\$194,251	\$/yr.	Calculation
<u>NO_x Emission Reduction</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Baseline NO _x Emissions	Uncontrolled (135 ppmvd at 15%O ₂)	21.30	lb/hr	Permit Limit
Controlled NO _x Emissions	Controlled (42 ppmv at 15% O ₂)	7.76	lb/hr	Permit Limit
NO_x Emission Reduction	Emissions Differential	59.31	tpy	Calculation
Cost Effectiveness		\$3,275	\$/ton	Calculation

Cromwell, CT Solar Centaur (T2) Dry Low NO_x Combustor Cost Effectiveness				
<u>Capital Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Total Capital Investment (TCI)	TCI	\$950,000	\$/turbine	Project Cost
Total Capital Costs		\$950,000	\$	Calculation
<u>Operating Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$30	\$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		\$3,120	\$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	\$468	\$/yr.	OAQPS
Total Operating Costs		\$3,588	\$/yr.	Calculation
<u>Maintenance Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$36	\$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		\$5,760	\$/yr.	Calculation
Material Cost	100% of Maintenance Cost	\$5,760	\$/yr.	OAQPS
Total Maintenance Costs		\$11,520	\$/yr.	Calculation
Total O&M Costs		\$15,108	\$/yr.	Calculation
<u>Indirect Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Overhead	60% of O&M Costs	\$9,065	\$/yr.	OAQPS
Administration	2% of TCI	\$19,000	\$/yr.	OAQPS
Insurance	1% of TCI	\$9,500	\$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	\$141,578	\$/yr.	OAQPS
Total Indirect Costs		\$179,143	\$/yr.	Calculation
Total Annual Costs	O&M Costs + Indirect Cost	\$194,251	\$/yr.	Calculation
<u>NO_x Emission Reduction</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Baseline NO _x Emissions	Uncontrolled (110 ppmvd at 15%O ₂)	17.39	lb/hr	Permit Limit
Controlled NO _x Emissions	Controlled (42 ppmv at 15% O ₂)	7.76	lb/hr	Permit Limit
NO_x Emission Reduction	Emissions Differential	42.18	tpy	Calculation
Cost Effectiveness		\$4,605	\$/ton	Calculation

C.2Case Study GT-2, Duke Energy, Southeast, New York

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in the town of Southeast, NY, are two Solar Centaur turbines and one Solar Mars turbine that drive compressors. These simple-cycle gas-turbine engines are rated at 4700 hp each for the Centaurs and 13,000 hp for the Mars.

The turbines were put in place before New York's Reasonably Available Control Technology (RACT) requirements were in place. Therefore, it was necessary to reduce NO_x emissions by 1995 when these rules took effect.

The units operate as needed to meet gas transmission demands.

The turbines were retrofitted with Dry Low NO_x (DLN) Combustor technology was implemented in order to achieve the necessary NO_x reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was evaluated as the most cost-effective approach.

General Statistics on Duke Energy Southeast, NY, Gas Turbine	
Turbine Type	Solar Centaurs and Mars simple-cycle compressor drive
HP	2 x 4,700 hp (Centaur) 1 x 13,000 hp (Mars)
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NO_x	Centaur - 135 ppmvd at 15%O ₂ (permit) Mars - 167 ppmvd at 15%O ₂ (permit)
Controlled NO_x	50 ppmvd at 15%O ₂ (permit)

Project Execution

The technology was retrofitted onto the turbines in 1993, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was \$3.5 million. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1993 with the Dry Low NO_x retrofit. During that time, the emissions from the turbines have been maintained under the required level and within the guarantee levels. In the roughly 72 months of operation, the NO_x reduction system has resulted in 50 turbine outages and a total of 450 lost operating hours for both gas turbines at the facility. The shut downs and lost hours were due to frequent flameouts during weather changes which were not

handled well by the first-generation of fuel controls. Duke Energy has since equipped the turbines with more modern electronic fuel controls from the manufacturer that have addressed this problem. The Mars fuel injectors also plugged frequently until a finer upstream filter corrected this problem. Roughly two man-hours per week of additional service is needed to maintain the turbines.

The first generation combustor liner failed after about 5000 hours. However, a new, third generation combustor liner appears to be operating properly for over 10,000 hours. The cost of replacing a combustor liner is roughly \$20,000, including labor and materials.

Experience and Performance	
Months in operation (as of Aug '99)	72
Increased parasitic loads	None
Change in turbine efficiency	None
Project Cost	\$3.5 million Centaur - \$775,000 per turbine Mars - \$1,950,000
Estimated add'l fixed O&M	\$15,000/year
Add'l man-hours of labor	see Cost Effectiveness Calculations
NOx guarantee, ppm	42 ppmvd at 15%O ₂
NOx guarantee met?	Yes
Combustor Life prior to DLN	20,000 + hrs
Combustor Life after DLN	5,000-10,000 hrs *
Number of forced outages	50 *
Total lost operating hours	450 *
* New fuel controls have addressed the frequent forced outage problem that contributed to high lost operating hours. First-generation combustor liners failed after about 5,000 hours. New, third-generation combustor liner appears to have increased the combustor life to 10,000 hours or more.	

Cost Effectiveness

Ost effectiveness spreadsheets from Duke Energy appear on the following two pages.

Southeast, NY Solar Centaurs Dry Low NO_x Combustor Cost Effectiveness				
<u>Capital Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Total Capital Investment (TCI)	TCI	\$775,000	\$/turbine	Project Cost
Total Capital Costs		\$775,000	\$	Calculation
<u>Operating Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$30	\$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		\$3,120	\$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	\$468	\$/yr.	OAQPS
Total Operating Costs		\$3,588	\$/yr.	Calculation
<u>Maintenance Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$36	\$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		\$5,760	\$/yr.	Calculation
Material Cost	100% of Maintenance Cost	\$5,760	\$/yr.	OAQPS
Total Maintenance Costs		\$11,520	\$/yr.	Calculation
Total O&M Costs		\$15,108	\$/yr.	Calculation
<u>Indirect Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Overhead	60% of O&M Costs	\$9,065	\$/yr.	OAQPS
Administration	2% of TCI	\$15,500	\$/yr.	OAQPS
Insurance	1% of TCI	\$7,750	\$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	\$115,498	\$/yr.	OAQPS
Total Indirect Costs		\$147,813	\$/yr.	Calculation
Total Annual Costs	O&M Costs + Indirect Cost	\$162,921	\$/yr.	Calculation
<u>NO_x Emission Reduction</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Baseline NO _x Emissions	Uncontrolled (135 ppmvd at 15%O ₂)	21.60	lb/hr	Permit Limit
Controlled NO _x Emissions	Controlled (50 ppmv at 15% O ₂)	7.59	lb/hr	Permit Limit
NO_x Emission Reduction	Emissions Differential	61.36	tpy	Calculation
Cost Effectiveness		\$2,655	\$/ton	Calculation

Southeast, NY Solar Mars Dry Low NO_x Combustor Cost Effectiveness				
<u>Capital Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Total Capital Investment (TCI)	TCI	\$1,950,000	\$/turbine	Project Cost
Total Capital Costs		\$1,950,000	\$	Calculation
<u>Operating Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$30	\$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		\$3,120	\$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	\$468	\$/yr.	OAQPS
Total Operating Costs		\$3,588	\$/yr.	Calculation
<u>Maintenance Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$36	\$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		\$5,760	\$/yr.	Calculation
Material Cost	100% of Maintenance Cost	\$5,760	\$/yr.	OAQPS
Total Maintenance Costs		\$11,520	\$/yr.	Calculation
Total O&M Costs		\$15,108	\$/yr.	Calculation
<u>Indirect Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Overhead	60% of O&M Costs	\$9,065	\$/yr.	OAQPS
Administration	2% of TCI	\$39,000	\$/yr.	OAQPS
Insurance	1% of TCI	\$19,500	\$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	\$290,608	\$/yr.	OAQPS
Total Indirect Costs		\$358,280	\$/yr.	Calculation
Total Annual Costs	O&M Costs + Indirect Cost	\$373,280	\$/yr.	Calculation
<u>NO_x Emission Reduction</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Baseline NO _x Emissions	Uncontrolled (167 ppmvd at 15%O ₂)	75.68	lb/hr	Permit Limit
Controlled NO _x Emissions	Controlled (42 ppmv at 15% O ₂)	7.70	lb/hr	Permit Limit
NO_x Emission Reduction	Emissions Differential	297.75	tpy	Calculation
Cost Effectiveness		\$1,254	\$/ton	Calculation

C.3Case Study GT-3, Duke Energy, Stony Point, New York

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Stony Point, NY are two Solar Centaur turbines and one Solar Mars turbine that drive compressors. These simple-cycle gas-turbine engines are rated at 4700 hp each (Centaur) and 13,000 hp (Mars).

The turbines were put in place before New York's Reasonably Available Control Technology (RACT) requirements were in place. Therefore, it was necessary to reduce NOx emissions by 1995 when these rules took effect.

The units operate as needed to meet gas transmission demands.

The turbines were retrofitted with Dry Low NOx (DLN) Combustor technology was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was evaluated as the most cost-effective approach.

General Statistics on Duke Energy Stony Point NY, Gas Turbines	
Turbine Type	Solar Centaur and Mars simple-cycle compressor drives
HP	2 x 4700 hp (Centaur) 1 x 13,000 (Mars)
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	Centaur - 135 ppmvd at 15%O ₂ (permit) Mars - 167 ppmvd at 15%O ₂ (permit)
Controlled NOx	42 ppmvd at 15%O ₂ (permit)

Project Execution

The technology was retrofitted onto the turbines in 1993, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was \$3.5 million. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1993 with the Dry Low NOx retrofit. During that time, the emissions of the turbines have been maintained under the required level and within the guarantee levels. In the roughly 72 months of operation, the NOx reduction system has resulted in 200 turbine outages and a total of 2,000 lost operating hours for all gas turbines at the facility. The shut downs

and lost hours were due to frequent flameouts during weather changes which were not handled well by the first-generation fuel controls. Duke has since equipped the turbines with more modern electronic fuel controls from the manufacturer that have addressed this problem. The Mars fuel injectors also plugged frequently until a finer upstream filter corrected this problem. Roughly two man-hours per week of additional service is needed to maintain the turbines.

The first generation combustor liner failed after about 5000 hours. However, a new, third generation combustor liner appears to be operating properly for over 10,000 hours. The cost of replacing a combustor liner is roughly \$20,000, including labor and materials.

Experience and Performance	
Months in operation (as of Aug '99)	72
Increased parasitic loads	None
Change in turbine efficiency	None
Project Cost	\$3.5 million Centaur - \$775,000 per turbine Mars - \$1,950,000
Estimated add'l fixed O&M	\$15,000/year
Add'l man-hours of labor	see Cost Effectiveness Calculations
NOx guarantee, ppm	42 ppmvd at 15%O ₂
NOx guarantee met?	Yes
Combustor Life prior to DLN	20,000 + hrs
Combustor Life after DLN	5,000-10,000 hrs
Number of forced outages	200
Total lost operating hours	2,000
New fuel controls have addressed the frequent forced outage problem that contributed to high lost operating hours. First-generation combustor liners failed after about 5,000 hours. New, third-generation combustor liner appears to have increased the combustor life to 10,000 hours or more.	

Cost Effectiveness

Ost effectiveness spreadsheets from Duke Energy appear on the following two pages.

Stony Point, NY Solar Centaurs Dry Low NO_x Combustor Cost Effectiveness				
<u>Capital Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Total Capital Investment (TCI)	TCI	\$775,000	\$/turbine	Project Cost
Total Capital Costs		\$775,000	\$	Calculation
<u>Operating Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$30	\$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		\$3,120	\$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	\$468	\$/yr.	OAQPS
Total Operating Costs		\$3,588	\$/yr.	Calculation
<u>Maintenance Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$36	\$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		\$5,760	\$/yr.	Calculation
Material Cost	100% of Maintenance Cost	\$5,760	\$/yr.	OAQPS
Total Maintenance Costs		\$11,520	\$/yr.	Calculation
Total O&M Costs		\$15,108	\$/yr.	Calculation
<u>Indirect Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Overhead	60% of O&M Costs	\$9,065	\$/yr.	OAQPS
Administration	2% of TCI	\$15,500	\$/yr.	OAQPS
Insurance	1% of TCI	\$7,750	\$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	\$115,498	\$/yr.	OAQPS
Total Indirect Costs		\$147,813	\$/yr.	Calculation
Total Annual Costs	O&M Costs + Indirect Cost	\$162,921	\$/yr.	Calculation
<u>NO_x Emission Reduction</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Baseline NO _x Emissions	Uncontrolled (135 ppmvd at 15%O ₂)	27.00	lb/hr	Permit Limit
Controlled NO _x Emissions	Controlled (42 ppmv at 15% O ₂)	7.70	lb/hr	Guarantee/Permit Limit
NO_x Emission Reduction	Emissions Differential	84.53	tpy	Calculation
Cost Effectiveness		\$1,927	\$/ton	Calculation

Stony Point, NY Solar Mars Dry Low NO_x Combustor Cost Effectiveness				
<u>Capital Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Total Capital Investment (TCI)	TCI	\$1,950,000	\$/turbine	Project Cost
Total Capital Costs		\$1,950,000	\$	Calculation
<u>Operating Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$30	\$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		\$3,120	\$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	\$468	\$/yr.	OAQPS
Total Operating Costs		\$3,588	\$/yr.	Calculation
<u>Maintenance Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$36	\$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		\$5,760	\$/yr.	Calculation
Material Cost	100% of Maintenance Cost	\$5,760	\$/yr.	OAQPS
Total Maintenance Costs		\$11,520	\$/yr.	Calculation
Total O&M Costs		\$15,108	\$/yr.	Calculation
<u>Indirect Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Overhead	60% of O&M Costs	\$9,065	\$/yr.	OAQPS
Administration	2% of TCI	\$39,000	\$/yr.	OAQPS
Insurance	1% of TCI	\$19,500	\$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	\$290,608	\$/yr.	OAQPS
Total Indirect Costs		\$358,172	\$/yr.	Calculation
Total Annual Costs	O&M Costs + Indirect Cost	\$373,280	\$/yr.	Calculation
<u>NO_x Emission Reduction</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Baseline NO _x Emissions	Uncontrolled (167 ppmvd at 15%O ₂)	85.47	lb/hr	Permit Limit
Controlled NO _x Emissions	Controlled (42 ppmv at 15% O ₂)	7.70	lb/hr	Guarantee/Permit Limit
NO_x Emission Reduction	Emissions Differential	340.63	tpy	Calculation
Cost Effectiveness		\$1,096	\$/ton	Calculation

C.4Case Study GT-4 Kern River and Sycamore Cogeneration Projects, Bakersfield, California

Operator Contact: Daniel Beck (661) 392-2461

Background and Technology Selection

Kern River and Sycamore Cogeneration Companies operate cogeneration and gas compression equipment in Bakersfield, CA. The gas turbines are GE Frame 7's that drive gas compression equipment. Each facility (Kern River and Sycamore) has four turbines each. Each gas turbine is rated at 75 MW, for a facility rating of 300 MW per facility. All four of Sycamore's turbines and two of Kern River's turbines have model EA compressors attached. The other two units at Kern River have model E compressors (not quite as large as the model EA compressors).

Both facilities were originally equipped with water injection for NO_x control. Additional reductions were required that were beyond the capability of water injection. Therefore, it was determined that water injection would be removed from the turbines and the turbines would be retrofitted with Dry Low NO_x combustors, which were recently made available by the turbine manufacturer, General Electric.

General Statistics on Kern River and Sycamore Cogeneration Projects	
Turbine Type	GE Frame 7
Gas Turbine Output	4 x 75 MW (Kern River) 4 x 75 MW (Sycamore)
Heat Recovery	Yes, HRSG
Fuel(s)	Natural Gas
Capacity Factor	Over 95% both facilities
Previous Controlled NO_x (with water injection)	30-40 ppm
Guaranteed Outlet NO_x	15 ppm
Controlled NO_x (with DLN)	8-12 ppm

The units operate almost continuously, with historical capacity factors of 96.2% and 98.4% at Kern River and Sycamore, respectively.

DLN is capable of 15 ppm of NO_x (which approximates to just under 50 lb/hr at full load per turbine). The conventional combustors with water injection that the turbines were previously equipped with, were capable of under 42 ppm.

Project Execution

The first unit was retrofitted in 1995 and the last one was retrofitted in May of 1999. The most recent retrofit took about 24 days to complete, with the work being awarded to the turbine manufacturer - General Electric. It cost about \$3.65 million to retrofit each unit.

Experience

Depending on the turbine, operating experience ranges from a few months to four years. During this time there have been a total of 10-20 short-term NOx exceedances, under five forced outages and fewer than 100 lost operating hours. There is no additional labor associated with operating the units with DLN.

Most of the exceedances have been associated with re-ignition problems. In this case, the unit is only in an unstable state for a very short time (i.e., five minutes), but the resulting emissions have sent the units over 1-hr or 3-hr average limits. The facility owners are currently working with the supplier on two outstanding items. They resulted in 4-5 emission exceedances in a short time (i.e., 1-month).

There are a number of advantages DLN has over water injection that are in addition to NOx reduction.

- Since the DLN retrofit, heat rate has improved 4% versus water injection.
- With water injection, combustor life was only 5-6 years. The Kern River and Sycamore operators are hoping for over ten years of combustor life with the DLN combustor.
- Finally, facility consumption of water is reduced from what it would have been with all units running with water injection. This is important especially in dry regions such as Bakersfield, CA.

Experience and Performance	
Months in operation (as of Aug '99)	3 to 48, depending on the turbine
Increased parasitic loads	None
Change in turbine efficiency	4% improvement
Project Cost	\$3.65 million/turbine
Estimated add'l fixed O&M	None (actually, O&M was reduced compared to water injection)
Add'l man-hours of labor	None
NOx guarantee, ppm	15 ppm
NOx guarantee met?	Yes
Combustor Life prior to DLN	5-6 yrs
Combustor Life after DLN	Unknown, hoping for over 10 years
Number of NOx exceedances	10-20 *
Number of forced outages	<5
Total lost operating hours	<100
* Exceedances were due to short-term transients (typically under 5-minutes), but were sufficient to cause one-hour or three hour averages to exceed maximum allowed. Facility operators are working with supplier to resolve outstanding items.	

Cost Effectiveness

Sycamore and Kern River did not provide their analysis of cost effectiveness. However, they did evaluate the project on a 10-year life.

C.5Case Study GT-5 PG&E Generating, Manchester Street Station, Providence, Rhode Island

Company Contact: Paula Hamel

Background and Technology Selection

PG&E Generating owns and operates a power plant in Providence, RI. The facility is equipped with three 165 MW Combined Cycle Gas Turbines (CCGT - each CCGT is a 120 MW gas turbine and a 45 MW steam turbine). The turbines primarily fire natural gas and have #2 fuel oil available as a back up. The facility was placed in service in 1995 and was required to meet a NO_x emission rate of 9 ppm. The CCGT's were originally equipped with steam injection and SCR in order to meet the emission limit. In 1998 PG&E Generating retrofitted the gas turbine engines with Dry Low NO_x (DLN) combustor technology in order to facilitate low NO_x emissions in a more cost-effective manner.

General Statistics on Manchester Street Station	
Turbine Type	Siemens
Gas Turbine Output	3 x 120 MW
Heat Recovery	Yes, HRSG
Fuel(s)	Natural Gas #2 Fuel Oil backup
Year turbines in service	1995
Year that DLN NO_x reduction system was placed in service	1998
Capacity Factor	~80%
Baseline (uncontrolled) NO_x (with steam injection)	<42 ppm
Guaranteed Outlet NO_x (with DLN)	9 ppm
Controlled NO_x (with DLN)	~7 ppm

The units have operated at about 80% capacity factor. The SCR uses aqueous ammonia as a reagent.

The Dry Low NO_x (DLN) technology replaced the steam injection technology for gas operation (steam injection is still used when firing oil), and it has made injection of ammonia for the SCR unnecessary for NO_x compliance under most conditions when firing natural gas. When firing #2 fuel oil it is necessary to use the SCR to achieve the required NO_x level of under 9 ppm. The retrofit was motivated by the reduced operating costs of DLN, which make it a cost-effective approach to reduce NO_x.

Project Execution

The original steam injection system and SCR were installed when the turbines were put in place in 1995. The DLN technology was retrofitted on the facility only a few years later and was in service in 1998.

Experience

Operating experience with the turbines is four years and operating experience with the DLN technology is for one to two years. During this time there have not been any exceedances of the Federal NSPS for NOx emissions from gas turbines (40CFR60 subpart GG). There has been one forced outage per turbine due to pluggage of ammonia injection (for the SCR) and about 24 lost operating hours per turbine. There is no additional labor associated with operating the units with DLN.

Experience and Performance	
Months in operation (as of Oct '99)	47-48, depending on turbine
Months since DLN retrofit	18
Increased parasitic loads	None
Change in turbine efficiency	DLN improved efficiency
NOx guarantee, ppm	9 ppm
NOx guarantee met?	Yes
Number of NOx exceedances	None (Federal NSPS)
Number of forced outages	1 on each turbine from SCR ammonia injector plugging
Total lost operating hours	About 24 on each turbine

Cost Effectiveness

PG&E Generating did not provide capital or operating cost data.

C.6Case Study GT-6 PG&E Generating, Pittsfield Generating Plant, Pittsfield, Massachusetts

Company Contact: Paula Hamel

Background and Technology Selection

PG&E Generating owns and operates a power plant in Pittsfield, MA. The facility is equipped with three Combined Cycle Gas Turbines (CCGTs), each with a 40 MW gas turbine. The facility also provides cogeneration steam. The turbines primarily fire natural gas and have #2 fuel oil available as a back up. The facility was placed in service in 1990 and was required to meet a NOx emission rate of 16.2 pounds per hour. The CCGT's were originally equipped with steam injection and SCR (using aqueous ammonia) in order to meet the emission limit.

General Statistics on Pittsfield Generating Plant	
Gas Turbine Output	3 x 40 MW
Heat Recovery	Yes, HRSG
Fuel(s)	Natural Gas #2 Fuel Oil backup
Year that turbines were placed in service	1990
Capacity Factor	Not available
Controlled NOx	< 16.2 lb/hr

Project Execution

The steam injection system and SCR were installed when the turbines were placed in service in 1990.

Experience

Operating experience is about 113 months (as of September 1999). During this time there have not been any exceedances of the Federal NSPS for NOx emissions from gas turbines (40CFR60 subpart GG). There were two forced outages per turbine due to plugging of ammonia injection (for the SCR) and about 12 total lost operating hours per turbine.

Experience and Performance	
Months in operation (as of September '99)	113 per turbine
NOx without steam injection with SCR	35 ppm
NOx with steam injection and with SCR	7 ppm
CO with steam injection	2-4 ppm
Steam flow : Fuel Flow (mass basis)	1.12 : 1
NOx guarantee, ppm	9 ppm
NOx guarantee met?	Yes
Number of NOx exceedances	None (Federal NSPS)
Number of forced outages	2 on each turbine from SCR ammonia injector plugging
Total lost operating hours	About 12 on each turbine

Cost Effectiveness

PG&E Generating did not provide capital or operating cost data.

C.7Case Study GT-7, Tennessee Gas Pipeline, Lockport, New York

Operator Contact - Sam Clowney (713) 420-3968

Background and Technology Selection

Tennessee Gas Pipeline owns and operates natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Lockport, NY, are four Solar Centaur turbine that drive compressors. These simple-cycle gas-turbine engines are rated at 4500 hp. The units were subject to RACT review requirements that took effect due to the units producing greater than 500 hp.

The units operate as needed to meet gas transmission demands.

TGP evaluated several technologies to comply with New York State Department of Environmental Conservation (NYSDEC) presumptive RACT levels of 50 ppm for gas turbines and selected Dry Low NO_x Combustor technology to achieve the presumptive NO_x RACT. This was the approach required by the State of New York's RACT compliance plans.

General Statistics on Tennessee Gas Pipeline, Lockport, NY	
Turbine Type	Solar Centaur simple-cycle compressor drive
HP	4 x 4500 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Baseline (uncontrolled) NO_x	87 ppm (nominal OEM guarantee)
Controlled NO_x	50 ppm (guarantee)

Project Execution

The technology was retrofitted onto the turbines in time to satisfy RACT requirements. The cost of this retrofit, including commissioning, was \$2.5 million. Three of the turbines cost \$600,000 each to retrofit, and the oldest turbine cost \$700,000 to retrofit. These project costs include extensive engineering and company overhead costs. Project execution details were not available.

Experience

The facility has been operating since 1995 with the Dry Low NO_x retrofit. During that time, the emissions of the turbines have been maintained under the required permit level and within the manufacturer's guaranteed levels.

Experience and Performance	
Months in operation (as of Oct '99)	48
Increased parasitic loads	None
Change in turbine efficiency	None
Project Cost	\$600,000 to \$700,000 per turbine
Estimated add'l fixed O&M	See cost - effectiveness Calculations
Add'l man-hours of labor	5 days/turbine-yr.
NOx guarantee, ppm	50 ppm
NOx guarantee met?	Yes
Combustor Life prior to DLN	Insufficient data
Combustor Life after DLN	Insufficient data
Number of forced outages	0
Total lost operating hours	0

Cost Effectiveness

Cost effectiveness spreadsheets from Tennessee Gas Pipeline appear on the following page.

Lockport, NY
Solar Centaur
DryLoNOx Cost Effectiveness

<i>Cost</i>	<i>Basis</i>	<i>Value</i>	<i>Reference</i>
Total Capital Investment (TCI)	TCI	\$700,000	Project Cost

	<i>Basis</i>	<i>Value</i>	<i>Reference</i>
Operating Labor			
Unit Cost	Hourly rate	\$30.00	Industry Average
Labor Required	1 hr/week	52	Estimate
Total Cost (\$/yr)		\$1,560	Calculation
Supervisor Labor			
Labor Required	15% Operating Labor	\$234	OAQPS
Total Cost (\$/yr)		\$234	Calculation
Maintenance			
Unit Cost	Hourly rate	\$36.00	Industry Average
Labor Required	80 hrs/year	80	Estimate
Maintenance Cost		\$2,880	Calculation
Material Cost	100% of Maintenance Cost	\$2,880	Calculation
Total Cost (\$/yr)		\$5,760	Calculation
Indirect			
Overhead	60% of O&M Costs	\$4,532	OAQPS
Administration	2% of TCI	\$14,000	OAQPS
Insurance	1% of TCI	\$7,000	OAQPS
Cost Recovery Factor (CRF)	10 Years, 8% Interest	0.149	OAQPS
Capital Recovery	TCI x CRF	\$104,321	Calculation
Total Indirect Costs (\$/yr)		\$129,853	Calculation
Base Case Emission Rate	Uncontrolled @ 87 ppm; lb/hr	16.800	Solar Guarantee
NO _x Emission rate	DryLoNOx Guarantee @ 50 ppm; lb/hr	10.200	Permit Limit
Total NO _x Controlled (ton/yr)	Emission Differential; tpy	28.9	Calculation
Total Annual Cost (\$/yr)	Summation	\$137,407	Calculation
COST EFFECTIVENESS (\$/ton)		\$4,753	

D. Internal Combustion Engine Case Studies

D.1 Case Study IC-1, SYCOM Enterprises, Linden, New Jersey

Operator Contact - Donald Moore

Background and Technology Selection

SYCOM Enterprises is an energy services firm that operates a facility for Buckeye Pipeline's fuel pumping station in Linden, NJ. This pumping facility, which was placed in service in January 1997, is powered by three 3130-hp, gas-fired Waukesha engines. These gas-fired engines were used to replace the existing electrically driven pumps, which are more expensive to operate. As a new internal combustion engine facility, the engines were subject to New Jersey's strict environmental permitting requirements. The requirements of the state of New Jersey made it necessary to install Selective Catalytic Reduction technology for reduction of NO_x.

General Statistics on SYCOM Enterprise's Linden, NJ Engine Facility	
Engine Type	Waukesha, reciprocating
HP	3 x 3130 hp
Operating since	January 1997 (2 ½ years)
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	~92%
Baseline (uncontrolled) NO_x	Not Available
Controlled NO_x	50 ppm

The units operate nearly continuously, with shut downs for periodic maintenance or during changes in pumping operations. Each engine typically operates 18 or more hours per day.

Project Execution

The SCR was installed as a part of a packaged unit with the engine. Each catalyst reactor has two layers of NO_x reducing catalyst and a downstream catalyst for removing CO. Aqueous ammonia is used for the SCR reagent. Each of the three engines is served by its own SCR system. There is a common aqueous ammonia storage system for all three SCR's.

Experience

The facility has been operating since January 1997. The system has met its guaranteed NO_x emissions level. These engines are not equipped with Continuous Emissions Monitors. Emissions are checked by a monthly emissions test.

The only significant operating difficulties have been: 1) occasional plugging of the ammonia injector by rust flakes from upstream piping, which prevents effective and efficient SCR operation until the problem is corrected; 2) failure of ammonia pumps, that have been since repaired; 3) and

the need to clean the catalyst due to deposition of lubricants from the engine during start-up cycles. The increased cost due to the injector plugging is estimated at about \$3,000-4,000 per year and the catalyst cleaning has been necessary twice on each of two of the engines and once on the third. Since the catalyst supplier provided for this, the additional cost due to this primarily results from having to own a spare catalyst layer while the other layer is off for cleaning.

Experience and Performance	
Months in operation (as of July '99)	30
Increased parasitic loads	Unknown
Change in engine efficiency	Unknown
Reagent cost per year	\$14,000
Cost of service agreement for SCR	\$78,000/year <i>(equal to \$2166/month for each engine)</i>
Cost of additional testing	\$9,600/year
NOx guarantee, ppm	50 ppm
NOx guarantee met?	Yes
Catalyst washes	Five total on three engines - <i>Two for each of two engines</i> <i>Once for the third</i>

Cost Effectiveness

SYCOM Enterprises was unable to provide the capital cost of the SCR system because it was provided as a part of the engine package and was not a separate line item on the contract. Since capital cost is a major determinant of the cost effectiveness, it is not possible to determine this value without more information.

D.2 Case Study IC-2, Duke Energy, Stony Point, New York

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Stony Point, NY are four Clark TLA8 engines. These are two-stroke reciprocating gas engines, 2700 hp each.

The engines are about 40 years old, manufactured well before NOx requirements were in place. As a part of New York's Reasonably Available Control Technology (RACT) requirements, it was necessary to reduce NOx emissions to below 5.1 gm/hp-hr of NOx in 1995.

The units operate as needed to meet gas transmission demands.

High-energy ignition was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was the most cost-effective approach.

General Statistics on Duke Energy Stony Point IC Engines	
Engine Type	Clark TLA8, two-stroke, reciprocating
HP	4 x 2700 hp
Facility age	~ 40 years
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	10.08 gm/hp-hr (permit)
Controlled NOx	5.1 gm/hp-hr (permit)

Project Execution

The technology was retrofitted onto the engines in 1994, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was \$304,000. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1994 with the high-energy ignition upgrade. During that time, the emissions of the engines have been maintained under the required level. In the roughly 60 months of operation, the NOx reduction system has resulted in six engine outages and a total of 24 lost operating hours. Roughly two man-hours per week of additional service are needed to maintain the engines.

Experience and Performance	
Months in operation (as of Aug '99)	60
Increased parasitic loads	None
Change in engine efficiency	None
Project Cost	\$76,000 per engine
Estimated add'l fixed O&M	see Cost Effectiveness Calculations
Add'l man-hours of labor	2 hours/week per engine
Controlled NOx emissions	5.1 gm/hp-hr
Number of forced outages	6
Total lost operating hours	24

Cost Effectiveness

The cost effectiveness spreadsheets from Duke Energy appear on the following page.

Stony Point, NY Clark TLA8 High Energy Ignition System Cost Effectiveness				
<u>Capital Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Total Capital Investment (TCI)	TCI	\$76,000	\$/engine	Project Cost
Total Capital Costs		\$76,000	\$	Calculation
<u>Operating Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$30	\$/hr	Industry Average
Operating Labor Required	2 hrs/wk/engine	104	hrs/yr.	Experience
Operating Labor Cost		\$3,120	\$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	\$468	\$/yr.	OAQPS
Total Operating Costs		\$3,588	\$/yr.	Calculation
<u>Maintenance Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$36	\$/hr	Industry Average
Maintenance Labor Required	62 hrs/yr./engine	62	hrs/yr.	Estimate
Maintenance Labor Cost		\$2,232	\$/yr.	Calculation
Material Cost	100% of Maintenance Cost	\$2,232	\$/yr.	OAQPS
Total Maintenance Costs		\$4,464	\$/yr.	Calculation
Total O&M Costs		\$8,052	\$/yr.	Calculation
<u>Indirect Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Overhead	60% of O&M Costs	\$4,831	\$/yr.	OAQPS
Administration	2% of TCI	\$1,520	\$/yr.	OAQPS
Insurance	1% of TCI	\$760	\$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	\$11,326	\$/yr.	OAQPS
Total Indirect Costs		\$18,437	\$/yr.	Calculation
Total Annual Costs	O&M Costs + Indirect Cost	\$26,489	\$/yr.	Calculation
<u>NO_x Emission Reduction</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Baseline NO _x Emissions	Uncontrolled (10.08 g/hp-hr)	60.00	lb/hr	Permit Limit
Controlled NO _x Emissions	Controlled (5.1 g/hp-hr)	30.36	lb/hr	Permit Limit
NO_x Emission Reduction	Emissions Differential	129.84	tpy	Calculation
Cost Effectiveness		\$204	\$/ton	Calculation

D.3 Case Study IC-3, Duke Energy, Burrillville, Rhode Island

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Burrillville, RI are three Clark TLA8 engines. These are two stroke reciprocating gas engines, 2700 hp each.

The engines are about 40 years old, manufactured well before NOx requirements were in place, and previously emitted about 12 gm/hp-hr. As part of Rhode Island's Reasonably Available Control Technology (RACT) requirements, it was necessary to reduce NOx emissions to below 1.4 lb/MMBTU, which is equal to 5.1 gm/hp-hr of NOx on these engines, by 1995.

The units operate as needed to meet gas transmission demands.

High-energy ignition was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was the most cost-effective approach.

General Statistics on Duke Energy Burrillville, RI, IC Engines	
Engine Type	Clark TLA8, two-stroke, reciprocating
HP	3 x 2700 hp
Facility age	~ 40 years
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	10.08 gm/hp-hr (test data)
Controlled NOx	1.4 lb/MMBTU (permit) (equivalent to 5.1 gm/hp-hr)

Project Execution

The technology was retrofitted onto the engines in 1994, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was \$228,000. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1994 with the high-energy ignition upgrade. During that time, the emissions of the engines have been maintained under the required level. In the roughly 60 months of operation, the NOx reduction system has resulted in six engine outages but no lost operating hours. Roughly two man-hours per week of additional service is needed to maintain the engines.

Experience and Performance	
Months in operation (as of Aug '99)	60
Increased parasitic loads	None
Change in engine efficiency	None
Project Cost	\$76,000 per engine
Estimated add'l fixed O&M	see Cost Effectiveness Calculations
Add'l man-hours of labor	2 hours/week per engine
Controlled NOx emission	1.4 lb/MMBTU (equivalent to 5.1 gm/hp-hr)
Number of forced outages	6
Total lost operating hours	0

Cost Effectiveness

The cost effectiveness spreadsheets from Duke Energy appear below.

Burrillville, RI Clark TLA8 High Energy Ignition System Cost Effectiveness				
<u>Capital Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Total Capital Investment (TCI)	TCI	\$76,000	\$/engine	Project Cost
Total Capital Costs		\$76,000	\$	Calculation
<u>Operating Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$30	\$/hr	Industry Average
Operating Labor Required	2 hrs/wk/engine	104	hrs/yr.	Experience
Operating Labor Cost		\$3,120	\$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	\$468	\$/yr.	OAQPS
Total Operating Costs		\$3,588	\$/yr.	Calculation
<u>Maintenance Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$36	\$/hr	Industry Average
Maintenance Labor Required	62 hrs/yr./engine	62	hrs/yr.	Estimate
Maintenance Labor Cost		\$2,232	\$/yr.	Calculation
Material Cost	100% of Maintenance Cost	\$2,232	\$/yr.	OAQPS
Total Maintenance Costs		\$4,464	\$/yr.	Calculation
Total O&M Costs		\$8,052	\$/yr.	Calculation
<u>Indirect Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Overhead	60% of O&M Costs	\$4,831	\$/yr.	OAQPS
Administration	2% of TCI	\$1,520	\$/yr.	OAQPS
Insurance	1% of TCI	\$760	\$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	\$11,326	\$/yr.	OAQPS
Total Indirect Costs		\$18,437	\$/yr.	Calculation
Total Annual Costs	O&M Costs + Indirect Cost	\$26,489	\$/yr.	Calculation
<u>NO_x Emission Reduction</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Baseline NO _x Emissions	Uncontrolled (10.08 g/hp-hr)	60.00	lb/hr	Test Data
Controlled NO _x Emissions	Controlled (5.1 g/hp-hr)	30.36	lb/hr	Permit Limit
NO_x Emission Reduction	Emissions Differential	129.84	tpy	Calculation
Cost Effectiveness		\$204	\$/ton	Calculation

D.4 Case Study IC-4, Duke Energy, Cromwell, Connecticut

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Cromwell, CT are six Cooper GMWA8 engines. These are two stroke reciprocating gas engines, 2000 hp each.

The engines are about 42 years old, manufactured well before NOx requirements were in place, and previously emitted NOx at a rate of 14.53 gm/hp-hr. As part of Connecticut's Reasonably Available Control Technology (RACT) requirements, it was necessary to reduce NOx emissions to below 8.72 gm/hp-hr of NOx by 1995.

The units operate as needed to meet gas transmission demands.

High-energy ignition was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was evaluated as the most cost-effective approach.

General Statistics on Duke Energy Cromwell, CT, IC Engines	
Engine Type	Cooper GMWA8, two-stroke, reciprocating
HP	6 x 2000 hp
Facility age	~ 42 years
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	14.53 gm/hp-hr (permit)
Controlled NOx	8.72 gm/hp-hr (permit)

Project Execution

The technology was retrofitted onto the engines in 1994, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was \$145,000. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1994 with the high-energy ignition upgrade. During that time, the emissions of the engines have been maintained under the required level. In the roughly 60 months of operation, the NOx reduction system has resulted in six engine outages and a total of 12 lost operating hours. Roughly two man-hours per week of additional service is needed to maintain the engines.

Experience and Performance	
Months in operation (as of Aug '99)	60
Increased parasitic loads	None
Change in engine efficiency	None
Project Cost	\$24,167 per engine
Estimated add'l fixed O&M	\$8,000/year
Add'l man-hours of labor	2/week
Controlled NOx	8.72 gm/hp-hr
Number of forced outages	6
Total lost operating hours	12

Cost Effectiveness

The cost effectiveness spreadsheets from Duke Energy appear on the following page.

Cromwell, CT Cooper GMWA8 High Energy Ignition System Cost Effectiveness				
<u>Capital Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Total Capital Investment (TCI)	TCI	\$24,167	\$/engine	Project Cost
Total Capital Costs		\$24,167	\$	Calculation
<u>Operating Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$30	\$/hr	Industry Average
Operating Labor Required	2 hrs/wk/engine	104	hrs/yr.	Experience
Operating Labor Cost		\$3,120	\$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	\$468	\$/yr.	OAQPS
Total Operating Costs		\$3,588	\$/yr.	Calculation
<u>Maintenance Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Unit Cost	Hourly Rate	\$36	\$/hr	Industry Average
Maintenance Labor Required	62 hrs/yr./engine	62	hrs/yr.	Estimate
Maintenance Labor Cost		\$2,232	\$/yr.	Calculation
Material Cost	100% of Maintenance Cost	\$2,232	\$/yr.	OAQPS
Total Maintenance Costs		\$4,464	\$/yr.	Calculation
Total O&M Costs		\$8,052	\$/yr.	Calculation
<u>Indirect Costs</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Overhead	60% of O&M Costs	\$4,831	\$/yr.	OAQPS
Administration	2% of TCI	\$483	\$/yr.	OAQPS
Insurance	1% of TCI	\$242	\$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	\$3,602	\$/yr.	OAQPS
Total Indirect Costs		\$9,158	\$/yr.	Calculation
Total Annual Costs	O&M Costs + Indirect Cost	\$17,210	\$/yr.	Calculation
<u>NO_x Emission Reduction</u>	<u>Basis</u>	<u>Value</u>	<u>Units</u>	<u>Reference</u>
Baseline NO _x Emissions	Uncontrolled (14.53 g/hp-hr)	64.07	lb/hr	Permit Limit
Controlled NO _x Emissions	Controlled (8.72 g/hp-hr)	38.45	lb/hr	Permit Limit
NO_x Emission Reduction	Emissions Differential	112.20	tpy	Calculation
Cost Effectiveness		\$153	\$/ton	Calculation

D.5 Case Study IC-5, NORESKO, Plymouth Cogeneration, Plymouth, New Hampshire

Operator Contact - Jeff Neggers (603) 536-5115

Background and Technology Selection

NORESCO owns and operates a cogeneration facility on the grounds of Plymouth State College in Plymouth, NH. The facility has an 1800 HP, four-stroke diesel engine that runs on No. 2 fuel oil. This engine was put in place in 1994 and was required to comply with Best Available Control Technology (BACT), which was determined to be Selective Catalytic Reduction. The SCR system uses aqueous ammonia and reduces NO_x by 90%.

The engine operates nearly continuously, having historical capacity factors well above 90% and projected capacity factors even higher in the future.

General Statistics on NORESKO, Plymouth Cogeneration	
Engine Type	Diesel, 4-stroke
HP	1800 hp
Facility age	~ 5 years
Heat Recovery	Yes
Fuel(s)	No. 2 Fuel Oil
Historical Capacity Factor	93%
1998 Capacity Factor	95%
Projected Future Cap. Fctr.	98%
Baseline (uncontrolled) NO_x	1200 ppm
Controlled NO_x	1 gm/hp-hr (~120 ppm)

Project Execution

As a new engine, the SCR system was provided as part of a larger project. The SCR was placed in service at start up.

Because the original intent was to fire the engine on No. 6 fuel oil, the catalyst is somewhat oversized. The capital cost of the SCR was \$180,000.

Experience

The facility has been operating since 1994 with the SCR in operation since startup. In that time there have been no NO_x exceedances. The SCR has averaged about 4 forced outages per year totaling about 20 lost operating hours per year. These lost hours and outages are primarily due to the need to periodically clean the catalyst. Engine lubricating oil contributes to the soot and ash that build up over time on the catalyst. Additional labor required for the SCR is roughly 1 hour per week.

With 45,000 operating hours without a need for catalyst replacement, the catalyst is meeting its expected lifetime. The ammonia flow rate has also met its guarantee level at about 2.7 lb/hr.

Instrumentation with brass fittings located at the SCR inlet was found to fail rapidly due to corrosion from ammonia. Downstream equipment was unaffected due to the much lower ammonia concentration.

Experience and Performance	
Months in operation (as of Sept '99)	~ 60
Accumulated Operating Hours	45,000
Change in engine efficiency	Increased back pressure, up to maximum of 12" H ₂ O
Project Cost	\$180,000 (SCR only)
Estimated additional fixed O&M	\$2,000/year
Estimated additional variable O&M	\$21,000/yr
Additional man-hours of labor	1/week
Catalyst Replacement	None yet
Controlled NO_x	120 ppm (90% reduction, all loads)
Number of forced outages	~ 4/ yr.
Total lost operating hours	~20/yr

Cost Effectiveness

A detailed cost analysis for cost effectiveness was not done by NORESO. However, the SCR has facilitated cost savings in other aspects of the overall facility operation. Because this engine is operated almost continuously and controls to a low level, another engine at the facility is not required to install NO_x reduction equipment. Moreover, the high capacity factor of the engine permits it's HRSG to provide a significant portion of the university's heating load without any additional fuel being spent. Thus, this cogeneration project has resulted in several benefits, including environmental benefits.

D.6 Case Study IC-6, Tennessee Gas Pipeline, Mercer, Pennsylvania

Operator Contact - Sam Clowney (713) 420-3968

Background and Technology Selection

Tennessee Gas Pipeline owns and operates natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Mercer, PA are six Cooper GMV-10 engines. These are two-stroke reciprocating gas engines, site rated at 1100 hp each.

As part of Pennsylvania's Reasonably Available Control Technology (PA RACT) requirements, it was necessary to reduce NO_x emissions since the units produced greater than 500 hp.

TGP evaluated several technologies and chose parametric control (retarded ignition timing) as the cost-effective option for these engines in accordance with PA RACT regulations.

General Statistics on Tennessee Gas Pipeline - Mercer PA IC engine	
Engine Type	Cooper GMV-10, two-stroke, reciprocating
HP	6 x 1100 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Baseline (uncontrolled) NOx	10 gm/hp-hr
Controlled NOx	9 gm/hp-hr

The units operate as needed to meet gas transmission demands.

Project Execution

The technology was retrofitted onto the engines in time to satisfy RACT requirements. The cost of this retrofit, including commissioning, was \$4000 per engine. The project was implemented quickly, being a relatively minor change.

Experience

The facility has been operating since 1995 with the ignition timing retard. During that time, the emissions from the engines have been maintained at around 9 gm/hp-hr. There is additional maintenance due to increased carbon buildup in the engine with the retarded timing.

Experience and Performance	
Months in operation (as of Oct '99)	54
Increased fuel consumption	See Cost effectiveness calculations
Project Cost	See Cost effectiveness calculations
Estimated add'l maintenance	See Cost effectiveness calculations
Add'l cost of testing	See Cost effectiveness calculations
Controlled NOx emissions	9 gm/hp-hr
Number of forced outages	Insufficient Data
Total lost operating hours	0

Cost Effectiveness

Cost effectiveness spreadsheets from Tennessee Gas appear on the following page.

Mercer, PA
Cooper GMV-10
LEC Cost Effectiveness

<i>Cost</i>	<i>Basis</i>	<i>Value</i>	<i>Reference</i>
Total Capital Investment (TCI)	TCI	\$4,000	Project Cost

	<i>Basis</i>	<i>Value</i>	<i>Reference</i>
Operating Cost			
Unit Cost	Hourly Rate	\$30.00	
Labor Required	60 hrs/yr	60	
Total Cost (\$/yr)		\$1,800	Calculation
Supervisor Labor			
Labor Required	15% Operating Labor	\$270	OAQPS
Total Cost (\$/yr)		\$270	Calculation
Maintenance			
Unit Cost	Hourly rate	\$36.00	Industry Average
Labor Required	80 hrs/year	80	Estimate
Maintenance Cost		\$2,880	Calculation
	100% of Maintenance Cost + Added		
Material Cost	Fuel Cost	\$7,880	Calculation
Total Cost (\$/yr)		\$10,760	Calculation
Indirect			
Overhead	60% of O&M Costs	\$7,698.00	OAQPS
Administration	2% of TCI	\$80.00	OAQPS
Insurance	1% of TCI	\$40.00	OAQPS
Cost Recovery Factor (CRF)	10 Years, 8% Interest	0.149	OAQPS
Capital Recovery	TCI x CRF	\$596	Calculation
Total Indirect Costs (\$/yr)		\$8,414	Calculation
Base Case Emission Rate	Uncontrolled; lb/hr	35.110	Test Data
NO _x Emission rate	Controlled; lb/hr	31.600	Permit Limit
Total NO _x Controlled (ton/yr)	Emission Differential; tpy	15.4	Calculation
Total Annual Cost (\$/yr)	Summation	\$21,244	Calculation
COST EFFECTIVENESS (\$/ton)		\$1,382	

D.7 Case Study IC-7, Tennessee Gas Pipeline, Syracuse, New York

Operator Contact - Sam Clowney (713) 420-3968

Background and Technology Selection

Tennessee Gas Pipeline owns and operates natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Syracuse, NY are two Clark TLA-10 engines. These are two-stroke reciprocating gas engines, 3400 hp each.

As part of New York's Reasonably Available Control Technology (RACT) requirements, it was necessary to reduce NOx emissions since the units produced greater than 500 hp.

TGP evaluated several technologies to comply with NYSDEC presumptive RACT levels of 3 grams/BHP-hr for reciprocation engines and selected OEM low-emission combustion kits to achieve the presumptive NOx RACT. This was the approach required by the State of New York's RACT compliance plans.

General Statistics on Tennessee Gas Pipeline - Syracuse, NY IC Engines	
Engine Type	Clark TLA-10, two-stroke, reciprocating
HP	2 x 3400 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Baseline (uncontrolled) NOx	13 gm/hp-hr
Controlled NOx	3 gm/hp-hr

The units operate as needed to meet gas transmission demands.

Project Execution

The technology was retrofitted onto the engines in time to satisfy RACT requirements. (With extension granted by state) The cost of this retrofit, including commissioning, was \$1,164,000 per engine.

Experience

The facility has been operating since 1995 with the low emission combustion retrofits. During that time, the emissions of the engines have been maintained at 3 gm/hp-hr. There have been some maintenance difficulties associated with check valves to Pre-Combustion Chambers.

Experience and Performance	
Months in operation (as of Oct '99)	54
Project Cost	\$1,164,000 per engine
Controlled NOx emissions	3 gm/hp-hr
Number of forced outages	Insufficient Data
Total lost operating hours	Insufficient Data

Cost Effectiveness

Spreadsheet from Tennessee Gas detailing costs follows.

Syracuse, NY Clark TLA-8 LEC Cost Effectiveness

<i>Cost</i>	<i>Basis</i>	<i>Value</i>	<i>Reference</i>
Total Capital Investment (TCI)	TCI	\$1,164,000	Actual Project Cost

	<i>Basis</i>	<i>Value</i>	<i>Reference</i>
Operating Labor			
Unit Cost	Hourly rate	\$30.00	Industry Average
Labor Required	1 hr/shift, 3 shifts/day	1,095	Estimate
Total Cost (\$/yr)		\$32,850	Calculation
Supervisor Labor			
Labor Required	15% Operating Labor	\$4,928	OAQPS
Total Cost (\$/yr)		\$4,928	Calculation
Maintenance			
Unit Cost	Hourly rate	\$36.00	Industry Average
Labor Required	20 hrs/month	240	Estimate
Maintenance Cost		\$8,640	Calculation
Material Cost	100% of Maintenance Cost	\$8,640	Calculation
Total Cost (\$/yr)		\$17,280	Calculation
Indirect			
Overhead	60% of O&M Costs	\$33,035	OAQPS
Administration	2% of TCI	\$23,280	OAQPS
Insurance	1% of TCI	\$11,640	OAQPS
Cost Recovery Factor (CRF)	10 Years, 8% Interest	0.149	OAQPS
Capital Recovery	TCI x CRF	\$173,470	Calculation
Total Indirect Costs (\$/yr)		\$241,425	Calculation
Base Case Emission Rate	Uncontrolled; lb/hr	97.440	Test Data
NO _x Emission rate	Controlled; lb/hr	22.500	Permit Limit
Total NO _x Controlled (ton/yr)	Emission Differential; tpy	328.2	Calculation
Total Annual Cost (\$/yr)	Summation	\$296,482	Calculation
COST EFFECTIVENESS (\$/ton)		\$903	

D.8 Case Study IC-8, Tennessee Gas Pipeline, Coudersport, Pennsylvania

Operator Contact - Sam Clowney (713) 420-3968

Background and Technology Selection

Tennessee Gas Pipeline owns and operates natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Coudersport, PA are ten KVG-412 engines. These are four-stroke reciprocating gas engines, 1,320 hp each.

TGP evaluated several technologies and chose Non Selective Catalytic Reduction (NSCR) with retarded ignition timing as the cost-effective option for these engines in accordance with PA RACT regulations.

General Statistics on Tennessee Gas Pipeline – Coudersport, PA, IC Engine	
Engine Type	KVG-412, four-stroke, reciprocating
HP	10 x 1320 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Baseline (uncontrolled) NOx	20 gm/hp-hr
Controlled NOx	3 gm/hp-hr

The units operate as needed to meet gas transmission demands.

Project Execution

The technology was retrofitted onto the engines in time to satisfy RACT requirements. The cost of this retrofit, including commissioning, was \$150,000 per engine.

Experience

The facility has been operating since 1995 with the NSCR. During that time, the emissions of the engines have been maintained at 3 gm/hp-hr. Additional maintenance and testing is required, associated with the catalyst and the fuel/air ratio controls.

Experience and Performance	
Months in operation (as of Oct '99)	54
Project Cost	\$183,000 per engine
Estimated add'l maintenance	See cost effectiveness calc.
Add'l cost of testing	See cost effectiveness calc.
NOx emissions	3 gm/hp-hr
Number of forced outages	<20
Total lost operating hours	<1000

Cost Effectiveness

Cost effectiveness spreadsheets from Tennessee Gas follow.

Coudersport, PA
Ingersoll Rand KVG-412
NSCR Cost Effectiveness

<i>Cost</i>	<i>Basis</i>	<i>Value</i>	<i>Reference</i>
Total Capital Investment (TCI)	TCI	\$183,000	Actual Project Cost

	<i>Basis</i>	<i>Value</i>	<i>Reference</i>
Operating Labor			
Unit Cost	Hourly rate	\$24.00	Industry Average
Labor Required	1 hr/shift, 3 shifts/day	1,095	Estimate
Total Cost (\$/yr)		\$26,280	Calculation
Supervisor Labor			
Labor Required	15% Operating Labor	\$3,942	OAQPS
Total Cost (\$/yr)		\$3,942	Calculation
Maintenance			
Unit Cost	Hourly rate	\$36.00	Industry Average
Labor Required	1hrs/shift, 3 shifts/day	250	Estimate
Maintenance Cost		\$9,000	Calculation
Material Cost	100% of Maintenance Cost	\$9,000	Calculation
Testing Cost		\$600	Average
Total Cost (\$/yr)		\$18,600	Calculation
Indirect			
Overhead	60% of O&M Costs	\$29,293	OAQPS
Administration	2% of TCI	\$3,660	OAQPS
Insurance	1% of TCI	\$1,830	OAQPS
Cost Recovery Factor (CRF)	10 Years, 8% Interest	0.149	OAQPS
Capital Recovery	TCI x CRF	\$27,272	Calculation
Total Indirect Costs (\$/yr)		\$62,056	Calculation
Base Case Emission Rate	Uncontrolled; lb/hr	58.200	Test Data
NO _x Emission rate	Controlled; lb/hr	8.700	Permit Limit
Total NO _x Controlled (ton/yr)	Emission Differential; tpy	216.8	Calculation
Total Annual Cost (\$/yr)	Summation	\$110,878	Calculation
COST EFFECTIVENESS (\$/ton)		\$511	

E. Cement Kiln Case Studies

E.1 Case Study CK-1, California Portland Cement, Colton, California

Company Contact - John Bennett (626) 852-6261

Background and Technology Selection

California Portland Cement operates two (2) 1150 tons per day, long, dry kilns

General Statistics on California Portland Cement, Colton, California	
Facility Type	Two Long Dry Kilns
Production	2 x 1150 TPD
Original Fuels	Coal/Coke - 97% Natural Gas - 3%
Current Fuels (BTU basis)	Coal/Coke - 88% Tires - 10 % Nat. Gas - 2%
Approx. Facility Age	35 yrs
Year NOx Reduction in Service	1998
Baseline (uncontrolled) NOx	5.4 lb NOx/ton clinker
Controlled NOx	2.73 lb/ton clinker

California Portland Cement was required by the South Coast Air Quality Management District (SCAQMD) to reduce NOx emissions at the facility. The facility previously fired only coal/coke and natural gas. In order to reduce emissions, California Portland Cement decided to convert the kiln to indirect firing and mid-kiln firing with tires. Indirect Firing permits the use of a Low NOx Burner in the kiln. Firing tires mid-kiln enables the firing intensity in the primary combustion zone to be reduced, which helps to reduce NOx.

Project Execution

The technology was retrofitted onto the kiln in 1998. The project took 12 months and required a kiln shutdown of 4 weeks. The entire cost of the project, including equipment, installation and commissioning, was \$7 million.

Experience

The facility has been operating since 1998. The modifications have not had any adverse impact on kiln reliability. In fact it is expected that the kiln reliability should be improved with the indirect firing system because problems that may be experienced with the coal mill will not have an immediate impact on the burner operation.

If tires are added at the rate of one tire per rotation (equivalent to a fuel substitution rate on BTU basis of about 12%), the facility clinker production is reduced by about 10%. To date,

California Portland Cement has not determined a way to regain this lost capacity while operating the tire injection system.

Experience and Performance	
Months in operation (as of Aug '99)	10
Increased parasitic loads	Neg.
Project Capital Cost	\$7,000,000
Estimated add'l fixed O&M	\$250,000/year
Estimated add'l variable O&M	\$100,000
Approximate Baseline (uncontrolled) NOx	5.4 lb/ton clinker
Controlled NOx	2.73 lb/ton clinker
% reduction	~49%
Impact on Kiln reliability	10% reduction in plant production at tire addition rate of one tire per rotation.

Cost Effectiveness

The total capital charges were \$7 million and operation and maintenance costs a total of about \$350,000/yr (\$250,000 fixed and \$100,000 variable). The variable O&M cost is primarily associated with replacement of parts associated with the tire feeder and the burner tips.

E.2 Case Study CK-2, Texas Industries, Inc., Midlothian, Texas

Company Contact - Greg Mayes (972) 647 - 7058

Background and Technology Selection

Texas Industries is the largest producer of Portland Cement in Texas. One of their facilities is located just outside of Dallas in Midlothian, TX. The facility has four long-wet kilns with capacities of roughly 40 tons per hour each. The facility normally fires coal, combustible waste, and a small amount of natural gas. The waste is typically about one third of the heat input while the coal is typically 60% of the heat input.

Texas Industries has developed and patented the CemStarSM process, primarily as a method to increase plant capacity (U.S. patents: 5,421,880 and 5,494,515). Although they use CemStar to improve capacity, the Midlothian facility is equipped with Continuous Emissions Monitors and has monitored improvements in NOx emissions while operating with CemStar. Because of the fuel flexibility of the Midlothian plant, there is significant variability in the potential NOx emissions. Recent testing to characterize NOx emissions under well-controlled conditions generated the following results.

General Statistics on Texas Industries, Midlothian Texas, Cement Plant		
Facility Type	Four Long-Wet Kilns	
Production	4 x 40 TPH of clinker	
Typical Fuels (BTU basis)	Coal - $\geq 50\%$ Natural Gas $\leq 10\%$ Waste $\sim 33\%$	
Approx. Facility Age	39 yrs	
Year that NOx reduction system was placed in service	1995	
NOx Testing	Short Term Tests	Long Term Tests
Fuel Firing Condition	Coal $\sim 50\%$ Gas $\sim 50\%$ Waste - none	Coal $\sim 100\%$ Waste - none
Baseline (uncontrolled) NOx	813 pph	206 pph

Project Execution

TXI's Midlothian Cement Plant is where CemStar was originally developed. It is located adjacent to TXI's Chaparral Steel Mill, which provides the steel slag. The installation of equipment for CemStar (mostly, standard material handling equipment for the steel slag) required a kiln shutdown of two days. The capital cost of the equipment was \$250,000 per kiln.

Although the CemStar process has been used for years at the Midlothian Plant, emphasis so far has mostly been on capacity improvement rather than air pollution emissions improvement. For this reason, TXI recently conducted a series of tests under well-controlled kiln conditions to characterize the level of NOx reduction that CemStar provides.

Experience

The facility has been operating since 1961. The CemStar process has not had any adverse impact on kiln reliability. The results of recent tests to characterize NOx emissions with and without CemStar yielded the results shown below.

Short-term tests were conducted over a period of a few days and the long-term tests were conducted over a period of a few weeks for each condition. The tests were conducted at different conditions. In both cases significant NOx reduction was demonstrated - about 42% from conditions firing coal and gas and about 19% when operating under all-coal conditions.

Experience and Performance		
Months in operation (as of Aug '99)	50	
Increased parasitic loads	Neg.	
Increased Kiln Production Capacity	~10%	
Project Capital Cost	\$ 1 million	
Estimated add'l fixed O&M	\$20,000 /yr.	
Estimated add'l variable O&M	\$10,000/yr	
NO _x Testing	Short Term Tests	Long Term Tests
Fuel Firing Condition	Coal ~ 50% Gas ~ 50% Waste - none	Coal ~100% Waste - none
Uncontrolled Baseline NO _x	813 pph	206 pph
Controlled NO _x	471 pph	167 pph
Percent Reduction	42%	19%
Impact on Kiln reliability	No adverse impact	

Cost Effectiveness

The cost of employing CemStar includes the cost of capital equipment, about \$250,000 for each kiln at the Midlothian plant. In addition, there is a running royalty fee that is based upon the usage of steel slag. For the Midlothian plant, this royalty would have added a cost of about \$16 per ton of additional clinker produced. Rev 12/15/99

E.3 Case Study CK-3, Blue Circle Cement, Atlanta, Georgia

Company Contact - Tia Bohannon (404) 794-1561

Background and Technology Selection

Blue Circle Cement operates two (2) 950 ton per day (TPD) long, dry kilns

General Statistics on Blue Circle Cement kilns	
Facility Type	Two Long Dry Kilns
Production	2 x 950 TPD
Original Fuels	70% Coal, 30% Coke
Fuels After Retrofit	Coal/Coke 80% Tires - 20%
Approx. Facility Age	38 yrs
Year that NO _x reduction system was placed in service	1998
Baseline (uncontrolled) NO _x	510 ppm
Controlled NO _x	Currently in test phase

Blue Circle Cement decided to implement this technology to reduce NO_x emissions and also to take advantage of fuel savings and revenue potential for receiving tires. The economic benefit of

receiving the tires in place of purchasing coal is estimated by Blue Circle to be \$916,884 per year. Other technologies that Blue Circle considered was tire-derived-fuel (chipped tires) addition to the kiln back end. The facility is equipped with CEMS.

Project Execution

The technology was retrofitted onto the kilns in 1999. The project took 28 weeks and required a kiln shutdown of one week. The entire cost of the project, including equipment, installation and commissioning, was \$1,495,000. At this time Blue Circle is still testing the kilns. The process will be officially put in service in the year 2000.

Blue Circle Cement Mid-Kiln Project Schedule	
Award of Contract to Completion of Engineering	4 weeks
Award of Contract to Completion of installation	26 weeks
Award of Contract to system commissioning	28 weeks
Total weeks from Award of Contract	28 weeks
Total Required Shutdown Period for Retrofitting of Kiln	1 week

Experience

The facility is still being tested. Thus far, the modifications have not had any adverse impact on product quality.

Experience and Expected Performance	
Months in operation (as of Jan 2000)	Still in testing
Project Capital Cost	\$1,495,000
Estimated add'l fixed O&M	\$64,000/year
Estimated add'l labor m-h's	none
Estimated add'l variable O&M	Economic benefit estimated at \$916,884/year
Approx. Starting NOx	510 ppm
Expected Controlled NOx	350 ppm
% reduction	~30%
Impact on product quality	No adverse impact determined thus far

Cost Effectiveness

The total capital charges were \$1,495,000 and fixed operation and maintenance costs a total of about \$64,000/year with an expected net benefit of \$916,884/year due to fuel savings and tipping fee revenue. When Blue Circle cement evaluated this project, they used a 10-year project horizon.

E.4 Case Study CK-4, Ash Grove Cement, Foreman, Arkansas

Company Contact - Steve Bales (913) 451-8900

Background and Technology Selection

Ash Grove Cement operates one 1,300 tpd, wet kiln at this location that is the subject of this case study. Two smaller kilns are also burning tires at this location.

General Statistics on Ash Grove Cement kiln	
Facility Type	One Wet Kiln
Production	1,300 TPD
Original Fuels	73% Coal, 27% Waste
Fuels After Retrofit (BTU basis)	Coal 65%, Waste 27%, Tires - 8%
Approx. Facility Age	42 yr.
Year that NOx reduction system was placed in service	1998
Baseline NOx (with process control)	~383 lb. NOx/hr
Controlled NOx (with process control & tires)	~345 lb. NOx/hr

Ash Grove Cement decided to implement mid-kiln firing primarily to take advantage of fuel savings and revenue potential for receiving and burning tires. There is an immediate fuel replacement of 8% (BTU basis). In addition, Ash Grove receives a tipping fee from the State of Arkansas for the tires. The facility is also equipped with a Linkman process control system that has provided process improvements through reduction of kiln operating variability. The facility is equipped with a CEMS. When using Linkman, a process control strategy that uses NOx as an input, a substitution of 8% of the fossil fuel with tires, reduces the NOx emission rate from 383 lb./hr to 345 lb./hr. This 10% reduction of NOx is obtained by feeding one truck tire every third revolution of the kiln.

Project Execution

The technology was retrofitted onto the kiln in January 1998. The entire cost of the project, for this kiln, including equipment, installation and commissioning, was approximately \$500,000.

Experience

The facility has been burning tires for more than 25 months. The experience with the technology is outlined in the table below.

Performance before and after NOx based Process Control

Prior to the installation of the Linkman control method, the baseline for NOx without tires was 845 lb./hr. NOx emissions were reduced to 550 lb./hr through mid-kiln firing of tires - a 35% reduction of NOx. The process control strategies of the Linkman process control system using NOx are primarily for the purpose of maintaining process stability and are not specifically designed to control NOx. Nevertheless, NOx reduction does occur as a result of the improved process control with Linkman. The NOx emission level with Linkman alone without tire addition is 383 lb/hr - a 55% reduction from the uncontrolled NOx emission level of 845 lb./hr. The combined technologies of automated process control (Linkman) with mid-kiln firing of tires achieved a NOx emission level of 345 lb./hr - a 59% reduction from the totally uncontrolled level.

Figure IV-1 compares the frequency histogram of NOx emissions of Linkman process control alone to the frequency histogram of NOx emissions of Linkman process control with mid-kiln firing of tires. As demonstrated, the average NOx emissions for the combination of Linkman with mid-kiln firing of tires is 10% lower than that for kiln operation with Linkman alone.

The benefits of each control strategy are shown in Figure IV-2, A-D. Figure A shows a frequency histogram of NOx emissions for the uncontrolled condition. As shown, NOx is extremely variable. Figure B shows the effect of mid-kiln firing of tires alone. Clearly, the highest NOx values are diminished in frequency, resulting in 35% reduction in average NOx emissions from the conditions of Figure A. Figure C shows the effects of the Linkman process control alone. Again, the highest NOx emissions are avoided and only the lowest NOx emissions result, providing a 55% reduction in average NOx emissions from the conditions of Figure A. Figure D shows that the combined processes provide 59% reduction in NOx emissions from the conditions of Figure A. The arrows show the percent reduction for each condition to provide a combined 59% reduction of NOx emissions.

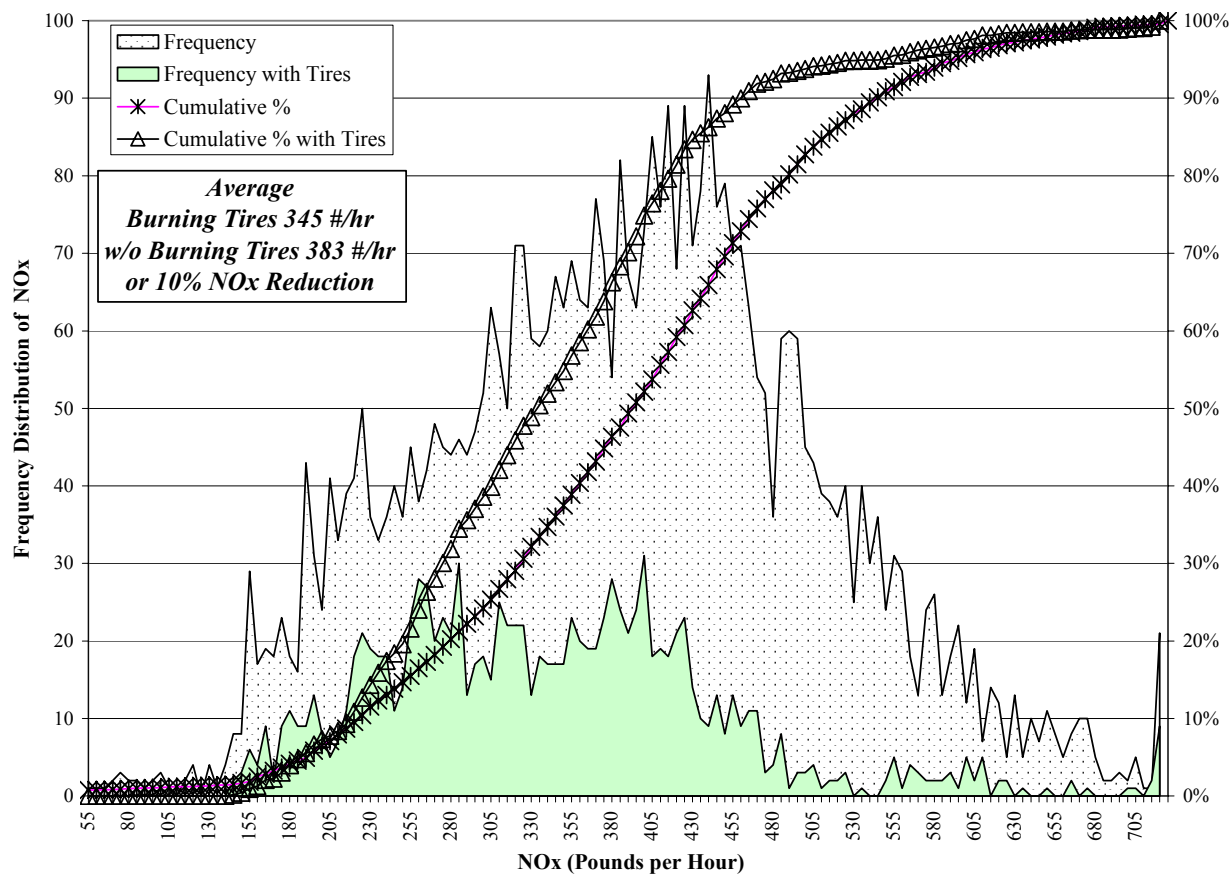
Experience and Expected Performance	
Months in operation (as of Jan 2000)	25
Project Capital Cost	\$500,000
Estimated add'l fixed O&M	\$15,000/year
Estimated add'l labor man-hours	One man-hour per shift ^{xi}
Estimated add'l variable O&M	Ash Grove receives a tipping fee from the State
Forced Outages from new equipment	Average 10 outage per year, however the kiln is not stopped to fix the problem until the next kiln outage
Lost operating hours from new equipment	Typically no hour are lost
Impact on product quality	No adverse impact

Cost Effectiveness

The total capital charges were \$500,000 for the mid-kiln firing system, and fixed operation and maintenance costs a total of about \$15,000/year. In addition, there are fuel savings and tipping fee revenue that justified this project purely from the perspective of return on investment. NOx reduction was not the primary motivation for proceeding with the project, but it was an additional benefit.

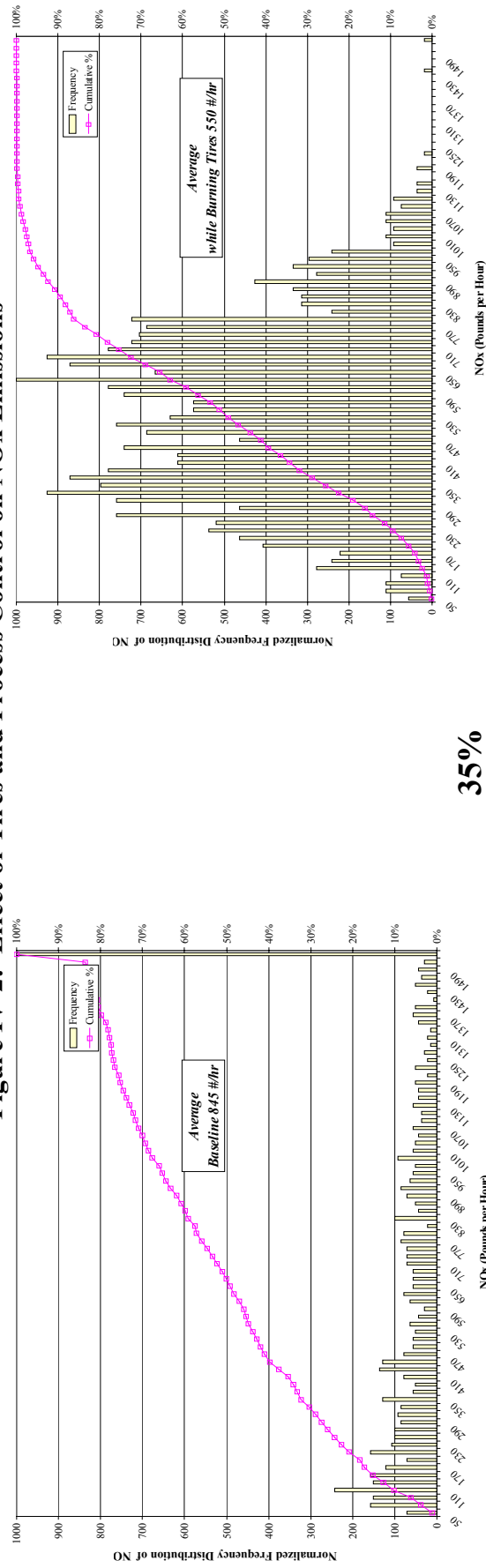
^{xi} It usually takes one man-hour to fix hung up tires or to put back tires that have fallen off the conveyer, for all three kilns.

Figure IV-1: Nitrogen Oxide Emission Burning Tires vs. Not-Burning Tires^{xii}



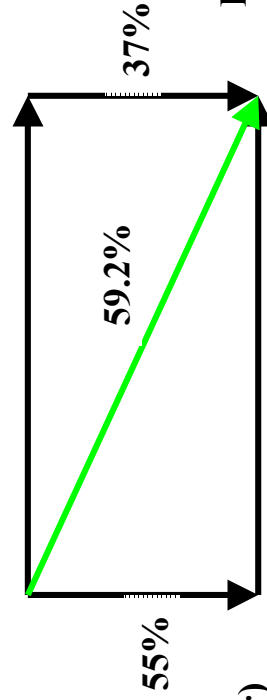
^{xii} There were 1,158 ½ hour average data points while burning tires and 4,595 ½ hour average data points without tires.

Figure IV-2: Effect of Tires and Process Control on NOx Emissions



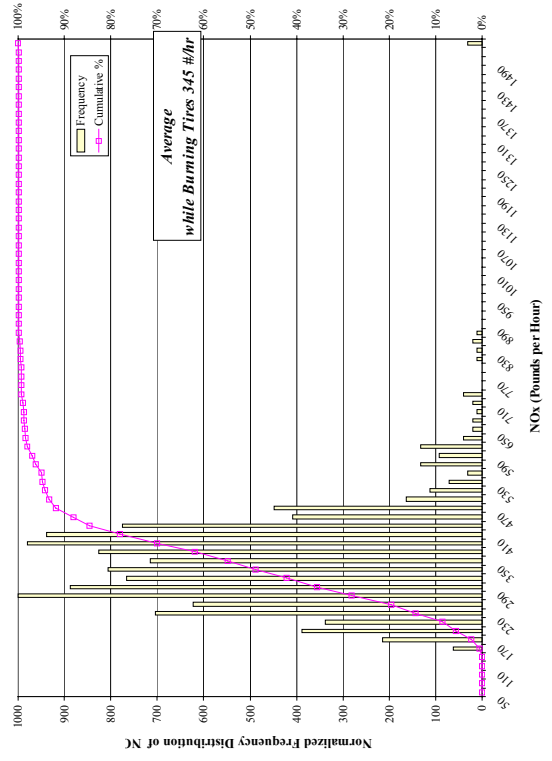
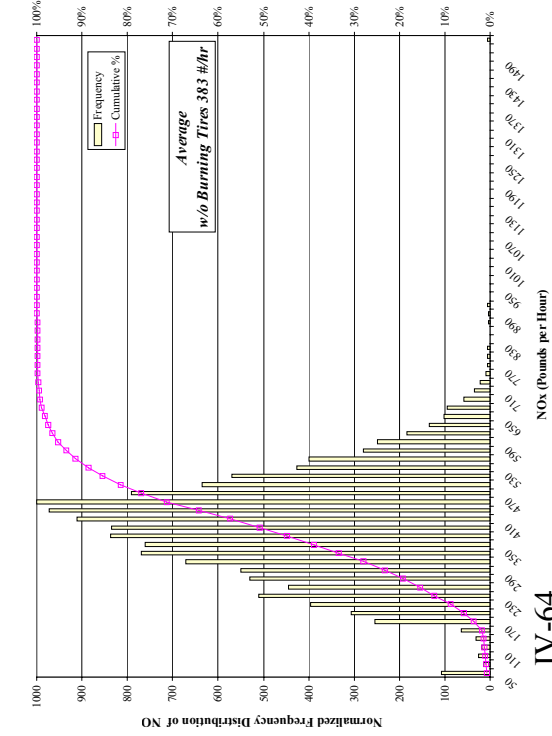
A. Baseline (845 lb./hr)

B. Tires (550 lb./hr)



C. Process Control (383 lb./hr)

D. Process Control & Tires (345 lb./hr)



Appendixes: Worksheets for Economic Analysis

The following worksheets were prepared to analyze the cost effectiveness of various NOx control approaches. For each condition evaluated, there were three linked worksheets: a project data sheet, a process analysis sheet, and a cash flow analysis sheet. What follows are examples of cost analysis for each source category. These examples do not include every condition analyzed in this report. The analysis shown includes the following:

1. A rigorous analysis of projected cash flows for a 15-year period analyzed on an after-tax basis. Because an after-tax analysis is interested in the net cash flow after taxes, the tax-reducing effects of depreciation and O&M cash expenditures are considered in this analysis. Although financing cash flows (i.e., debt principal and interest payments) are shown over project life, this is really for information purposes and does not figure into the final calculation of cost effectiveness. Capital and financing costs are treated in a manner typical in capital project analysis - applying a capital recovery factor using the WACC to determine an annual capital recovery.
2. A rigorous analysis of projected cash flows for a 15-year period analyzed on a before-tax basis. This is the same as the analysis above, except the tax-reducing effects of some expenses (such as depreciation) are not included.
3. A less rigorous analysis (but, no less valid) that uses a simplified capital recovery approach and assesses cost on a before-tax basis.

It is important to note that the results shown in tables of Chapter III of this report are the average of the results of methods #2 and #3. The reader will notice in the following tables that both of these approaches yielded similar results in all cases, demonstrating that the less rigorous approach is satisfactory for the purpose of this report or other similar efforts.

Although the worksheets in this appendix only show cash flows for the first 3 years, analysis was actually performed for the economic life of the project (15 years).

Boiler Worksheets

NOx Reduction Case Spreadsheet	
Boiler with Selective Non Catalytic Reduction	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.45
NOx reduction needed (up to 40%)	35%
boiler heat rate (BTU/kWh)	12,000
Outlet NOx Value	0.29
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	65%
Primary Fuel Cost (\$/MMBTU)	\$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Urea (\$/gallon)	\$0.95
Cost of Urea (\$/ton)	\$406.74
Urea Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$25,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital Cost (\$)	\$775,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
Pretax Rate of Return (ACT document)	10.0%

Boiler SNCR Process Analysis	
Plant	
MMBTU/hr	350
lb/hr NOx reduced	55
lbmole/hr NOx reduced	1
Pri. Fuel Cost, \$/MMBTU	\$1.50
Pri. Fuel Cost, \$/hr	\$525
Urea Cost (\$/gallon)	\$0.95
Urea Cost (\$/ton)	\$406.74
Urea Cost (\$/lbmole)	\$12.20
Urea Utilization	40%
Urea usage (lbmole/hr)	1.5
Urea usage (gal/hr)	19.25
Urea Cost (\$/hr)	\$18.28
Heat Rate Increase	0.50%
Uncontrolled NOx	0.45
Controlled NOx	0.29
Capital Cost, includes license (\$/kW)	775,000
Fixed O&M (\$/yr.)	\$25,000
Capacity factor	0.65
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	65

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$1,245,563)	(\$1,277,947)	(\$1,311,174)
Controlled Fuel Cost	\$0	(\$1,251,822)	(\$1,284,369)	(\$1,317,763)
Urea Cost	\$0	(\$43,365)	(\$44,493)	(\$45,650)
Total Variable O&M		(\$49,624)	(\$50,915)	(\$52,238)
Fixed O&M	\$0	(\$25,000)	(\$25,650)	(\$26,317)
Total O&M	\$0	(\$74,624)	(\$76,565)	(\$78,555)
Total Capital Cost	\$775,000			
Financed with Common Equity	(\$465,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$310,000)			
Debt payments		(\$35,119)	(\$35,119)	(\$35,119)
Interest portion of payment		(\$23,250)	(\$22,360)	(\$21,403)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$77,500)	(\$139,500)	(\$108,500)
EOP Book Value	\$775,000	\$697,500	\$558,000	\$449,500
Property Taxes		(\$11,625)	(\$10,463)	(\$8,370)
Adjustment for Income taxes		\$57,312	\$79,285	\$68,399
Net Cash Flow (current \$, incl. fin.)	(\$465,000)	(\$64,056)	(\$42,862)	(\$53,646)
Net Cash Flow (current \$, excl fin.)	(\$775,000)	(\$28,937)	(\$7,743)	(\$18,526)
Capital Expenditure Annuity @ WACC		(\$107,478)	(\$107,478)	(\$107,478)
NCF with annualized capital		(\$136,415)	(\$115,221)	(\$126,005)
Current \$ /ton of NOx reduced		(\$2,086.12)	(\$1,762.00)	(\$1,926.91)
NCF w/ann. cap. Discount by infl rate		(\$132,958)	(\$109,455)	(\$116,666)
Sum of discounted NCF	(\$1,823,151)			
TOTAL Tons NOx reduced Proj. Life	981			
\$/ton NOx reduced (after taxes)	(\$1,859)			
Before Tax Net Cash Flow		(\$193,728)	(\$194,505)	(\$194,404)
Discounted Before Tax NCF		(\$188,818)	(\$184,772)	(\$179,996)
Sum of discounted Before Tax NCF	(\$2,463,127)			
	981			
\$/ton NOx reduced (before tax basis)	(\$2,511)			
Annual Capital Recovery	(\$85,250)			
Annual O&M	(\$74,624)			
Total Cost	(\$159,874)			
Annual NOx reduced (tons)	65			
\$/ton (per ACT document)	(\$2,445)			
Average	(\$2,478)			

NOx Reduction Case Spreadsheet	
Boiler Selective Catalytic Reduction	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.45
NOx reduction needed (up to 90%)	80%
Outlet NOx Value	0.09
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Ammonia (\$/ton)	\$360.00
Ammonia Escalation (%/yr.)	2.6%
Catalyst Cost (\$/m3)	\$10,000
Op Hrs Between Catalyst Replacement	20,000
Estimated Fixed O&M in first year	\$50,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital cost (\$/MMBTU/hr)	\$12,500
Capital Cost (\$)	\$4,375,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Boiler SCR	
Plant	
MMBTU/hr	350
lb/hr NOx reduced	126
lbmole/hr NOx reduced	3
Pri. Fuel Cost, \$/MMBTU	\$1.50
Pri. Fuel Cost, \$/hr	\$525
Ammonia Cost (\$/ton)	\$360.00
Ammonia Cost (\$/lbmole)	\$3.06
Ammonia usage (lbmole/hr)	2.7
Ammonia usage (lb/hr)	46.57
Ammonia Cost (\$/hr)	\$8.38
Approx. Catalyst Loading (m3)	42
Heat Rate Increase	0.50%
Uncontrolled NOx	0.45
Controlled NOx	0.09
Capital Cost, includes license (\$/KW)	4,375,000
Fixed O&M (\$/yr.)	\$50,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	195

	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$3,909,150)	(\$4,010,788)	(\$4,115,068)
Controlled Fuel Cost	\$0	(\$3,928,794)	(\$4,030,943)	(\$4,135,747)
ammonia cost	\$0	(\$26,004)	(\$26,680)	(\$27,374)
annual catalyst addition		(\$52,122)	(\$53,477)	(\$54,868)
Total Variable O&M		(\$97,770)	(\$100,312)	(\$102,920)
Fixed O&M	\$0	(\$50,000)	(\$51,300)	(\$52,634)
Total O&M (incl. Dif. Fuel)	\$0	(\$147,770)	(\$151,612)	(\$155,554)
Total Capital Cost	\$4,375,000			
Financed with Common Equity	(\$2,625,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$1,750,000)			
Debt payments		(\$198,253)	(\$198,253)	(\$198,253)
Interest portion of payment		(\$131,250)	(\$126,225)	(\$120,823)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$437,500)	(\$787,500)	(\$612,500)
EOP Book Value	\$4,375,000	\$3,937,500	\$3,150,000	\$2,537,500
Property Taxes (net of income tax effect)		(\$65,625)	(\$59,063)	(\$47,250)
Adjustment for Income taxes		\$227,813	\$349,361	\$285,356
Net Cash Flow (current \$, incl. fin.)	(\$2,625,000)	(\$183,835)	(\$59,566)	(\$115,700)
Net Cash Flow (current \$, excl fin.)	(\$4,375,000)	\$14,418	\$138,686	\$82,552
Capital Expenditure Annuity @ WACC		(\$606,732)	(\$606,732)	(\$606,732)
NCF with annualized capital		(\$592,314)	(\$468,046)	(\$524,180)
Current \$ /ton of NOx reduced		(\$3,030.40)	(\$2,394.62)	(\$2,681.81)
NCF w/ann. cap. Discount by infl rate		(\$577,304)	(\$444,625)	(\$485,331)
Sum of discounted NCF	(\$7,692,965)			
TOTAL Tons NOx reduced Proj. Life	2,932			
\$/ton NOx reduced (after taxes)	(\$2,624)			
Before Tax Net Cash Flow		(\$820,127)	(\$817,407)	(\$809,536)
Discounted Before Tax NCF		(\$799,344)	(\$776,504)	(\$749,539)
Sum of discounted Before Tax NCF	(\$9,906,260)			
2,932				
\$/ton NOx reduced (before tax basis)	(\$3,379)			
Annual Capital Recovery	(\$481,250)			
Annual O&M	(\$147,770)			
Total Annual Cost	(\$629,020)			
Annual NOx reduced (tons)	195			
\$/ton (per ACT document)	(\$3,218.19)			
	(\$3,299)		average	

NOx Reduction Case Spreadsheet	
Gas Boiler with SCR	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.15
NOx reduction needed (up to 90%)	80%
Outlet NOx Value	0.03
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Ammonia (\$/ton)	\$360.00
Ammonia Escalation (%/yr.)	2.6%
Catalyst Cost (\$/m3)	\$10,000
Op Hrs Between Catalyst Replacement	20,000
Estimated Fixed O&M in first year	\$50,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital cost (\$/MMBTU/hr)	\$5,500
Capital Cost (\$)	\$1,925,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Plant	
MMBTU/hr	350
lb/hr NOx reduced	42
lbmole/hr NOx reduced	1
Pri. Fuel Cost, \$/MMBTU	\$1.50
Pri. Fuel Cost, \$/hr	\$525
Ammonia Cost (\$/ton)	\$360.00
Ammonia Cost (\$/lbmole)	\$3.06
Ammonia usage (lbmole/hr)	0.9
Ammonia usage (lb/hr)	15.52
Ammonia Cost (\$/hr)	\$2.79
Approx. Catalyst Loading (m3)	18
Heat Rate Increase	0.50%
Uncontrolled NOx	0.15
Controlled NOx	0.03
Capital Cost, includes license (\$/KW)	1,925,000
Fixed O&M (\$/yr.)	\$50,000
Capacity factor	0.85
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	156

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$3,909,150)	(\$4,010,788)	(\$4,115,068)
Controlled Fuel Cost	\$0	(\$3,928,794)	(\$4,030,943)	(\$4,135,747)
ammonia cost	\$0	(\$20,803)	(\$21,344)	(\$21,899)
annual catalyst addition		(\$10,859)	(\$11,141)	(\$11,431)
Total Variable O&M		(\$51,306)	(\$52,640)	(\$54,009)
Fixed O&M	\$0	(\$50,000)	(\$51,300)	(\$52,634)
Total O&M (incl. Dif. Fuel)	\$0	(\$101,306)	(\$103,940)	(\$106,643)
Total Capital Cost	\$1,925,000			
Financed with Common Equity	(\$1,155,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$770,000)			
Debt payments		(\$87,231)	(\$87,231)	(\$87,231)
Interest portion of payment		(\$57,750)	(\$55,539)	(\$53,162)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$192,500)	(\$346,500)	(\$269,500)
EOP Book Value	\$1,925,000	\$1,732,500	\$1,386,000	\$1,116,500
Property Taxes (net of income tax effect)		(\$28,875)	(\$25,988)	(\$20,790)
Adjustment for income taxes		\$112,938	\$166,750	\$138,926
Net Cash Flow (current \$, incl fin.)	(\$1,155,000)	(\$104,474)	(\$50,409)	(\$75,737)
Net Cash Flow (current \$, excl fin.)	(\$1,925,000)	(\$17,243)	\$36,822	\$11,494
Capital Expenditure Annuity @ WACC		(\$266,962)	(\$266,962)	(\$266,962)
NCF with annualized capital		(\$284,205)	(\$230,140)	(\$255,468)
Current \$ /ton of NOx reduced		(\$1,817.56)	(\$1,471.80)	(\$1,633.78)
NCF w/ann cap. Discount by infl rate		(\$277,003)	(\$218,624)	(\$236,535)
Sum of discounted NCF	(\$3,729,740)			
TOTAL Tons NOx reduced Proj. Life	2,345			
\$/ton NOx reduced (after taxes)	(\$1,590)			
Before Tax Net Cash Flow		(\$397,143)	(\$396,890)	(\$394,395)
Discounted Before Tax NCF		(\$387,079)	(\$377,029)	(\$365,165)
Sum of discounted Before Tax NCF	(\$4,889,270)			
	2,345			
\$/ton NOx reduced (before tax basis)	(\$2,085)			
Annual Capital Recovery	(\$211,750)			
Annual O&M	(\$101,306)			
Total Annual Cost	(\$313,056)			
Annual NOx reduced (tons)	156			
\$/ton (per ACT document)	(\$2,002.07)			
	(\$2,043)		average	

NOx Case Worksheet	
Conventional Gas Reburn	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.45
NOx reduction needed (up to 40%)	55%
boiler heat rate (BTU/KW hr)	10,000
Outlet NOx Value	0.20
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Percent Reburn Fuel, %	20.0%
Cost of Natural Gas (\$/MMBTU)	\$2.50
Natural Gas Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$25,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital Cost (\$)	\$700,000
Capital Cost (\$/MMBTU/hr)	\$2,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	20
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Plant	
MMBTU/hr	350
Pri. Fuel Cost, \$/MMBTU	\$1.50
Pri. Fuel Cost, \$/hr	\$420
Reburn Fuel Cost, \$/MMBTU	\$2.50
% Fuel Reburn zone	20.0%
Reburn Fuel Cost, \$/hr	\$175
Uncontrolled NOx	0.45
Controlled NOx	0.20
Capital Cost, (\$)	700,000
Fixed O&M (\$/yr.)	\$25,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	134

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$1,628,813)	(\$1,671,162)	(\$1,714,612)
Primary Fuel Cost	\$0	(\$1,303,050)	(\$1,336,929)	(\$1,371,689)
Reburn Fuel Cost	\$0	(\$542,938)	(\$557,054)	(\$571,537)
Tot. Controlled Fuel Cost	\$0	(\$1,845,988)	(\$1,893,983)	(\$1,943,227)
Variable O&M		(\$217,175)	(\$222,822)	(\$228,615)
Fixed O&M	\$0	(\$25,000)	(\$25,650)	(\$26,317)
Total O&M + dif. Fuel	\$0	(\$242,175)	(\$248,472)	(\$254,932)
Total Capital Cost	\$700,000			
Financed with Common Equity	(\$420,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$280,000)			
Debt payments		(\$27,466)	(\$27,466)	(\$27,466)
Interest portion of payment		(\$21,000)	(\$20,515)	(\$19,994)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$70,000)	(\$126,000)	(\$98,000)
EOP Book Value	\$700,000	\$630,000	\$504,000	\$406,000
Property Taxes		(\$10,500)	(\$9,450)	(\$7,560)
Adjustment for Income taxes		\$112,936	\$134,373	\$126,172
Net Cash Flow (current \$, incl fin.)	(\$420,000)	(\$167,205)	(\$151,015)	(\$163,785)
Net Cash Flow (current \$, excl fin.)	(\$700,000)	(\$139,739)	(\$123,549)	(\$136,320)
Capital Expenditure Annuity @ WACC		(\$97,077)	(\$97,077)	(\$97,077)
NCF with annualized capital		(\$236,816)	(\$220,626)	(\$233,397)
Current \$ /ton of NOx reduced		(\$1,762.32)	(\$1,641.84)	(\$1,736.88)
NCF w/ann cap. Discount by infl rate		(\$230,815)	(\$209,586)	(\$216,099)
Sum of discounted NCF	(\$3,307,565)			
TOTAL Tons NOx reduced Proj. Life	2,016			
\$/ton NOx reduced (after taxes)	(\$1,641)			
Before Tax Net Cash Flow		(\$349,752)	(\$354,999)	(\$359,569)
Discounted Before Tax NCF		(\$340,889)	(\$337,235)	(\$332,920)
Sum of discounted Before Tax NCF	(\$4,779,910)			
	2,016			
\$/ton NOx reduced (before tax basis)	(\$2,371)			
Annual Capital Recovery	(\$77,000)			
Annual O&M	(\$242,175)			
Total Cost	(\$319,175)			
Annual NOx reduced (tons)	134			
\$/ton (per ACT document)	(\$2,375)			
	\$2,373	average		

NOx Case Worksheet	
AE FLGR	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.45
NOx reduction needed (up to 70%)	60%
boiler heat rate (BTU/KW hr)	10,000
Outlet NOx Value	0.18
Urea NSR	1.2
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Natural Gas (\$/MMBTU)	\$2.50
Natural Gas Escalation (%/yr.)	2.6%
Urea Cost (\$/gallon)	\$0.95
Urea Cost (\$/ton)	\$406.74
Urea Escalation	2.6%
Estimated Fixed O&M in first year	\$25,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital Cost (\$)	\$875,000
Capital Cost (\$/MMBTU/hr)	\$2,500
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	20
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Plant	
MMBTU/hr	350
Pri. Fuel Cost, \$/MMBTU	\$1.50
Pri. Fuel Cost, \$/hr	\$494
Reburn Fuel Cost, \$/MMBTU	\$2.50
% Fuel Reburn zone	6.0%
Reburn Fuel Cost, \$/hr	\$53
Uncontrolled NOx	0.45
Controlled NOx	0.18
Initial NOx (full load), lb/hr	158
Initial NOx (full load), lbmole/hr	3.42
lbmole/hr urea	2.05
lb/hr urea	123
\$/hr urea (full load)	\$25
Capital Cost, \$)	875,000
Fixed O&M (\$/yr.)	\$25,000
Capacity factor	0.85
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	352

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$3,909,150)	(\$4,010,788)	(\$4,115,068)
Primary Fuel Cost	\$0	(\$3,674,601)	(\$3,770,141)	(\$3,868,164)
Reburn Fuel Cost	\$0	(\$390,915)	(\$401,079)	(\$411,507)
Tot. Controlled Fuel Cost	\$0	(\$4,065,516)	(\$4,171,219)	(\$4,279,671)
Urea Cost		(\$186,652)	(\$191,505)	(\$196,484)
Variable O&M		(\$343,018)	(\$351,937)	(\$361,087)
Fixed O&M	\$0	(\$25,000)	(\$25,650)	(\$26,317)
Total O&M + dif. Fuel	\$0	(\$368,018)	(\$377,587)	(\$387,404)
Total Capital Cost	\$875,000			
Financed with Common Equity	(\$525,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$350,000)			
Debt payments		(\$34,332)	(\$34,332)	(\$34,332)
Interest portion of payment		(\$26,250)	(\$25,644)	(\$24,992)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$87,500)	(\$157,500)	(\$122,500)
EOP Book Value	\$875,000	\$787,500	\$630,000	\$507,500
Property Taxes		(\$13,125)	(\$11,813)	(\$9,450)
Adjustment for Income taxes		\$164,025	\$191,415	\$181,774
Net Cash Flow (current \$, incl fin.)	(\$525,000)	(\$251,450)	(\$232,317)	(\$249,412)
Net Cash Flow (current \$, excl fin.)	(\$875,000)	(\$217,118)	(\$197,984)	(\$215,080)
Capital Expenditure Annuity @ WACC		(\$121,346)	(\$121,346)	(\$121,346)
NCF with annualized capital		(\$338,464)	(\$319,331)	(\$336,426)
Current \$ /ton of NOx reduced		(\$962.03)	(\$907.64)	(\$956.24)
NCF w/ann cap. Discount by infl rate		(\$329,887)	(\$303,351)	(\$311,493)
Sum of discounted NCF	(\$4,754,991)			
TOTAL Tons NOx reduced Proj. Life	5,277			
\$/ton NOx reduced (after taxes)	(\$901)			
Before Tax Net Cash Flow		(\$502,489)	(\$510,745)	(\$518,200)
Discounted Before Tax NCF		(\$489,756)	(\$485,188)	(\$479,795)
Sum of discounted Before Tax NCF	(\$6,929,556)			
	5,277			
\$/ton NOx reduced (before tax basis)	(\$1,313)			
Annual Capital Recovery	(\$96,250)			
Annual O&M	(\$368,018)			
Total Cost	(\$464,268)			
Annual NOx reduced (tons)	352			
\$/ton (per ACT document)	(\$1,320)			
Average of two methods	\$1,316	average		

NOx Case Worksheet	
Fuel Lean Gas Reburn	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.45
NOx reduction needed (up to 40%)	35%
boiler heat rate (BTU/KW hr)	10,000
Outlet NOx Value	0.29
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Natural Gas (\$/MMBTU)	\$2.50
Natural Gas Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$25,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital Cost (\$)	\$350,000
Capital Cost (\$/MMBTU/hr)	\$1,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	20
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Plant	
MMBTU/hr	350
Pri. Fuel Cost, \$/MMBTU	\$1.50
Pri. Fuel Cost, \$/hr	\$493
Reburn Fuel Cost, \$/MMBTU	\$2.50
% Fuel Reburn zone	6.1%
Reburn Fuel Cost, \$/hr	\$54
Uncontrolled NOx	0.45
Controlled NOx	0.29
Capital Cost, \$)	350,000
Fixed O&M (\$/yr.)	\$25,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	86

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$1,628,813)	(\$1,671,162)	(\$1,714,612)
Primary Fuel Cost	\$0	(\$1,529,048)	(\$1,568,803)	(\$1,609,592)
Reburn Fuel Cost	\$0	(\$166,275)	(\$170,598)	(\$175,033)
Tot. Controlled Fuel Cost	\$0	(\$1,695,322)	(\$1,739,401)	(\$1,784,625)
Variable O&M		(\$66,510)	(\$68,239)	(\$70,013)
Fixed O&M	\$0	(\$25,000)	(\$25,650)	(\$26,317)
Total O&M + dif. Fuel	\$0	(\$91,510)	(\$93,889)	(\$96,330)
Total Capital Cost	\$350,000			
Financed with Common Equity	(\$210,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$140,000)			
Debt payments		(\$13,733)	(\$13,733)	(\$13,733)
Interest portion of payment		(\$10,500)	(\$10,258)	(\$9,997)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$35,000)	(\$63,000)	(\$49,000)
EOP Book Value	\$350,000	\$315,000	\$252,000	\$203,000
Property Taxes		(\$5,250)	(\$4,725)	(\$3,780)
Adjustment for Income taxes		\$46,116	\$56,565	\$52,189
Net Cash Flow (current \$, incl fin.)	(\$210,000)	(\$64,377)	(\$55,782)	(\$61,655)
Net Cash Flow (current \$, excl fin.)	(\$350,000)	(\$50,644)	(\$42,049)	(\$47,922)
Capital Expenditure Annuity @ WACC		(\$48,539)	(\$48,539)	(\$48,539)
NCF with annualized capital		(\$99,182)	(\$90,588)	(\$96,460)
Current \$ /ton of NOx reduced		(\$1,159.86)	(\$1,059.35)	(\$1,128.02)
NCF w/ann cap. Discount by infl rate		(\$96,669)	(\$86,055)	(\$89,311)
Sum of discounted NCF	(\$1,372,708)			
TOTAL Tons NOx reduced Proj. Life	1,283			
\$/ton NOx reduced (after taxes)	(\$1,070)			
Before Tax Net Cash Flow		(\$145,298)	(\$147,153)	(\$148,649)
Discounted Before Tax NCF		(\$141,616)	(\$139,789)	(\$137,632)
Sum of discounted Before Tax NCF	(\$1,957,533)			
	1,283			
\$/ton NOx reduced (before tax basis)	(\$1,526)			
Annual Capital Recovery	(\$38,500)			
Annual O&M	(\$91,510)			
Total Cost	(\$130,010)			
Annual NOx reduced (tons)	86			
\$/ton (per ACT document)	(\$1,520)			
Average of two methods	\$1,523		average	

NOx Case Worksheet	
Low NOx Burners	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.6
NOx reduction needed (up to 40%)	25%
boiler heat rate (BTU/KW hr)	10,000
Outlet NOx Value	0.45
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Natural Gas (\$/MMBTU)	\$2.50
Natural Gas Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$0
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	0.00%
Capital Cost (\$)	\$1,750,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate MMBTU/hr	350
Pri. Fuel Cost, \$/MMBTU	\$1.50
Pri. Fuel Cost, \$/hr	\$525
Reburn Fuel Cost, \$/MMBTU	\$2.50
Uncontrolled NOx	0.60
Controlled NOx	0.45
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	81

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$1,628,813)	(\$1,671,162)	(\$1,714,612)
Controlled Fuel Cost	\$0	(\$1,628,813)	(\$1,671,162)	(\$1,714,612)
Variable O&M		\$0	\$0	\$0
Fixed O&M		\$0	\$0	\$0
Total O&M + dif. Fuel	\$0	\$0	\$0	\$0
Total Capital Cost	\$1,750,000			
Financed with Common Equity	(\$1,050,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$700,000)			
Debt payments		(\$79,301)	(\$79,301)	(\$79,301)
Interest portion of payment		(\$52,500)	(\$50,490)	(\$48,329)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$175,000)	(\$315,000)	(\$245,000)
EOP Book Value	\$1,750,000	\$1,575,000	\$1,260,000	\$1,015,000
Property Taxes		(\$26,250)	(\$23,625)	(\$18,900)
Adjustment for income taxes		\$70,438	\$118,519	\$92,365
Net Cash Flow (current \$, incl fin.)	(\$1,050,000)	(\$35,114)	\$15,593	(\$5,836)
Net Cash Flow (current \$, excl fin.)	(\$1,750,000)	\$44,188	\$94,894	\$73,465
Capital Expenditure Annuity @ WACC		(\$242,693)	(\$242,693)	(\$242,693)
NCF with annualized capital		(\$198,505)	(\$147,799)	(\$169,228)
Current \$ /ton of NOx reduced		(\$2,437.42)	(\$1,814.81)	(\$2,077.93)
NCF w/ann cap. Discount by infl rate		(\$193,475)	(\$140,403)	(\$156,686)
Sum of discounted NCF	(\$2,515,486)			
TOTAL Tons NOx reduced Proj. Life	1,222			
\$/ton NOx reduced (after taxes)	(\$2,059)			
Before Tax Net Cash Flow		(\$268,943)	(\$266,318)	(\$261,593)
Discounted Before Tax NCF		(\$262,128)	(\$252,991)	(\$242,205)
Sum of discounted Before Tax NCF	(\$3,098,350)			
TOTAL Tons NOx reduced Proj. Life	1,222			
\$/ton NOx reduced (before tax basis)	(\$2,536)			
Annual Capital Recovery	(\$192,500)			
Annual O&M	\$0			
Total Annual Cost	(\$192,500)			
Annual NOx reduced (tons)	81			
\$/ton (per ACT document)	(\$2,363.69)			
Average of both before-tax methods	\$2,450			

NOx Case Worksheet	
Low NOx Burners - Oil	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	1360
Initial NOx value (lb/MMBTU)	0.427
NOx reduction needed (up to 40%)	10%
boiler heat rate (BTU/KW hr)	10,000
Outlet NOx Value	0.38
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Natural Gas (\$/MMBTU)	\$2.50
Natural Gas Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$0
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	0.00%
Capital Cost (\$)	\$30,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate MMBTU/hr	1,360
Pri. Fuel Cost, \$/MMBTU	\$1.50
Pri. Fuel Cost, \$/hr	\$2,040
Reburn Fuel Cost, \$/MMBTU	\$2.50
Uncontrolled NOx	0.43
Controlled NOx	0.38
Capacity factor	0.85
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	216

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$15,189,840)	(\$15,584,776)	(\$15,989,980)
Controlled Fuel Cost	\$0	(\$15,189,840)	(\$15,584,776)	(\$15,989,980)
Variable O&M		\$0	\$0	\$0
Fixed O&M		\$0	\$0	\$0
Total O&M + dif. Fuel	\$0	\$0	\$0	\$0
Total Capital Cost	\$30,000			
Financed with Common Equity	(\$18,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$12,000)			
Debt payments		(\$1,359)	(\$1,359)	(\$1,359)
Interest portion of payment		(\$900)	(\$866)	(\$828)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$3,000)	(\$5,400)	(\$4,200)
EOP Book Value	\$30,000	\$27,000	\$21,600	\$17,400
Property Taxes		(\$450)	(\$405)	(\$324)
Adjustment for income taxes		\$1,208	\$2,032	\$1,583
Net Cash Flow (current \$, incl fin.)	(\$18,000)	(\$602)	\$267	(\$100)
Net Cash Flow (current \$, excl fin.)	(\$30,000)	\$758	\$1,627	\$1,259
Capital Expenditure Annuity @ WACC		(\$4,160)	(\$4,160)	(\$4,160)
NCF with annualized capital		(\$3,403)	(\$2,534)	(\$2,901)
Current \$ /ton of NOx reduced		(\$15.74)	(\$11.72)	(\$13.42)
NCF w/ann cap. Discount by infl rate		(\$3,317)	(\$2,407)	(\$2,686)
Sum of discounted NCF	(\$43,123)			
TOTAL Tons NOx reduced Proj. Life	3,243			
\$/ton NOx reduced (after taxes)	(\$13)			
Before Tax Net Cash Flow		(\$4,610)	(\$4,565)	(\$4,484)
Discounted Before Tax NCF		(\$4,494)	(\$4,337)	(\$4,152)
Sum of discounted Before Tax NCF	(\$53,115)			
TOTAL Tons NOx reduced Proj. Life	3,243			
\$/ton NOx reduced (before tax basis)	(\$16)			
Annual Capital Recovery	(\$3,300)			
Annual O&M	\$0			
Total Annual Cost	(\$3,300)			
Annual NOx reduced (tons)	216			
\$/ton (per ACT document)	(\$15.26)			
Average of both before-tax methods	\$16			

Gas Turbine Worksheets

NOx Case Worksheet	
75 MW GT - Dry Low NOx: from Diluent Injection	
Engine Technical Data	
Target Engine Size, (MW)	75
Initial NOx value (ppm)	42
Initial NOx massflow (lb/hr)	139.99
NOx reduction needed (up to 40%)	64%
Engine heat rate (BTU/KWhr)	10,000
Outlet NOx Value (ppm)	15.00
Outlet NOx massflow (lb/hr)	50.00
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	95%
Primary Fuel Cost (\$/MMBTU)	\$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$0
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	-4.00%
Capital Cost (\$)	\$3,650,000
Capital Cost (\$/KW)	\$49
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate MW	75
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr	\$1,688
Uncontrolled NOx (ppm)	42.00
Controlled NOx	15.00
Capital Cost	\$3,650,000
Fixed O&M (\$/yr.)	\$0
Capacity factor	0.95
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	374

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$14,043,375)	(\$14,408,503)	(\$14,783,124)
Controlled Fuel Cost	\$0	(\$13,481,640)	(\$13,832,163)	(\$14,191,799)
Fuel Savings		\$561,735	\$576,340	\$591,325
Water and Water Treatment savings (y or n)	y	\$313,500	\$321,651	\$330,014
Fixed O&M	\$0	\$0	\$0	\$0
Total O&M + dif. Fuel	\$0	\$875,235	\$897,991	\$921,339
Total Capital Cost	\$3,650,000			
Financed with Common Equity	(\$2,190,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$1,460,000)			
Debt payments		(\$165,399)	(\$165,399)	(\$165,399)
Interest portion of payment		(\$109,500)	(\$105,308)	(\$100,801)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$365,000)	(\$657,000)	(\$511,000)
EOP Book Value	\$3,650,000	\$3,285,000	\$2,628,000	\$2,117,000
Property Taxes		(\$54,750)	(\$49,275)	(\$39,420)
Adjustment for Income taxes		(\$104,370)	(\$10,619)	(\$71,872)
Net Cash Flow (current \$, incl fin.)	(\$2,190,000)	\$495,666	\$616,216	\$586,698
Net Cash Flow (current \$, excl fin.)	(\$3,650,000)	\$661,065	\$781,615	\$752,097
Capital Expenditure Annuity @ WACC		(\$506,188)	(\$506,188)	(\$506,188)
NCF with annualized capital		\$154,877	\$275,428	\$245,909
Current \$ /ton of NOx reduced		\$413.61	\$735.55	\$656.72
NCF w/ann cap. Discount by infl rate		\$150,953	\$261,645	\$227,684
Sum of discounted NCF	\$3,070,707			
TOTAL Tons NOx reduced Proj. Life	5,617			
\$/ton NOx reduced (after taxes)	\$547			
Before Tax Net Cash Flow		\$314,297	\$342,528	\$375,731
Discounted Before Tax NCF		\$306,332	\$325,388	\$347,884
Sum of discounted Before Tax NCF	\$6,333,561			
	5,617			
\$/ton NOx reduced (before tax basis)	\$1,128			
Annual Capital Recovery	(\$401,500)			
Annual O&M	\$875,235			
Total Annual Cost	\$473,735			
Annual NOx reduced (tons)	374			
\$/ton (per ACT document)	\$1,265			
Average (\$/ton)-both before-tax methods	\$1,196			

NOx Case Worksheet	
GT - 75 MW Dry Low NOx from Std. Combustor	
Engine Technical Data	
Target Engine Size, (MW)	75
Initial NOx value (ppm)	154
Initial NOx massflow (lb/hr)	513.28
NOx reduction needed (up to 40%)	90%
Engine heat rate (BTU/KWhr)	10,000
Outlet NOx Value (ppm)	15.00
Outlet NOx massflow (lb/hr)	50.00
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	45%
Primary Fuel Cost (\$/MMBTU)	\$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$0
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	0.00%
Capital Cost (\$)	\$3,650,000
Capital Cost (\$/KW)	\$49
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate MW	75
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr	\$1,688
Uncontrolled NOx (ppm)	154.00
Controlled NOx	15.00
Capital Cost	\$3,650,000
Fixed O&M (\$/yr.)	\$0
Capacity factor	0.45
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	913

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$6,652,125)	(\$6,825,080)	(\$7,002,532)
Controlled Fuel Cost	\$0	(\$6,652,125)	(\$6,825,080)	(\$7,002,532)
Fuel Savings		\$0	\$0	\$0
Water and Water Treatment savings (y or n)	n	\$0	\$0	\$0
Fixed O&M	\$0	\$0	\$0	\$0
Total O&M + dif. Fuel	\$0	\$0	\$0	\$0
Total Capital Cost	\$3,650,000			
Financed with Common Equity	(\$2,190,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$1,460,000)			
Debt payments		(\$165,399)	(\$165,399)	(\$165,399)
Interest portion of payment		(\$109,500)	(\$105,308)	(\$100,801)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$365,000)	(\$657,000)	(\$511,000)
EOP Book Value	\$3,650,000	\$3,285,000	\$2,628,000	\$2,117,000
Property Taxes		(\$54,750)	(\$49,275)	(\$39,420)
Adjustment for income taxes		\$146,913	\$247,196	\$192,647
Net Cash Flow (current \$, incl fin.)	(\$2,190,000)	(\$73,237)	\$32,522	(\$12,172)
Net Cash Flow (current \$, excl fin.)	(\$3,650,000)	\$92,163	\$197,921	\$153,227
Capital Expenditure Annuity @ WACC		(\$506,188)	(\$506,188)	(\$506,188)
NCF with annualized capital		(\$414,025)	(\$308,267)	(\$352,961)
Current \$ /ton of NOx reduced		(\$453.41)	(\$337.59)	(\$386.54)
NCF w/ann cap. Discount by infl rate		(\$403,534)	(\$292,841)	(\$326,802)
Sum of discounted NCF	(\$5,246,585)			
TOTAL Tons NOx reduced Proj. Life	13,697			
\$/ton NOx reduced (after taxes)	(\$383)			
Before Tax Net Cash Flow		(\$560,938)	(\$555,463)	(\$545,608)
Discounted Before Tax NCF		(\$546,723)	(\$527,667)	(\$505,171)
Sum of discounted Before Tax NCF	(\$6,462,273)			
	13,697			
\$/ton NOx reduced (before tax basis)	(\$472)			
Annual Capital Recovery	(\$401,500)			
Annual O&M	\$0			
Total Annual Cost	(\$401,500)			
Annual NOx reduced (tons)	913			
\$/ton (per ACT document)	(\$440)			
Average (\$/ton)-both before-tax methods	(\$456)			

NOx Reduction Case Spreadsheet	
Selective Catalytic Reduction 75 MW turbine with DLN	
Turbine Technical Data	
Engine Size (MW)	75
Initial NOx value (ppm)	15
Initial NOx massflow (lb/hr)	50.00
NOx reduction needed (up to 40%)	80%
Engine heat rate (BTU/KWhr)	10,000
Outlet NOx Value (ppm)	3.00
Outlet NOx massflow (lb/hr)	10.00
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Heat Rate Increase	0.5%
Cost of Ammonia (\$/ton)	\$360.00
Ammonia Escalation (%/yr.)	2.6%
Catalyst Cost (\$/m3)	\$14,000
Op Hrs Between Catalyst Replacement	42,000
Estimated Fixed O&M in first year	\$20,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital cost, (\$/KW)	\$60
Capital Cost (\$)	\$4,500,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Gas Turbine SCR	
MW	75.0
lb/hr NOx reduced	40.00
lbmole/hr NOx reduced	0.87
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr @ full load	\$1,688
Ammonia Cost (\$/ton)	\$360.00
Ammonia Cost (\$/lbmole)	\$3.06
Ammonia usage (lbmole/hr)	0.9
Ammonia usage (lb/hr)	14.78
Ammonia Cost (\$/hr)	\$2.66
Approx Catalyst Loading (m3)	57
Heat Rate Increase	0.50%
Uncontrolled NOx	15.00
Controlled NOx	3.00
Capital Cost, includes license (\$/KW)	4,500,000
Fixed O&M (\$/yr.)	\$20,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	62

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$12,565,125)	(\$12,891,818)	(\$13,227,006)
Controlled Fuel Cost	\$0	(\$12,628,266)	(\$12,956,601)	(\$13,293,473)
ammonia cost	\$0	(\$8,255)	(\$8,469)	(\$8,689)
annual catalyst addition		(\$142,063)	(\$145,757)	(\$149,547)
Total Variable O&M		(\$213,459)	(\$219,009)	(\$224,704)
Fixed O&M	\$0	(\$20,000)	(\$20,520)	(\$21,054)
Total O&M (incl. Dif. Fuel)	\$0	(\$233,459)	(\$239,529)	(\$245,757)
Total Capital Cost	\$4,500,000			
Financed with Common Equity	(\$2,700,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$1,800,000)			
Debt payments		(\$203,917)	(\$203,917)	(\$203,917)
Interest portion of payment		(\$135,000)	(\$129,831)	(\$124,275)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$450,000)	(\$810,000)	(\$630,000)
EOP Book Value	\$4,500,000	\$4,050,000	\$3,240,000	\$2,610,000
Property Taxes (net of income tax effect)		(\$67,500)	(\$60,750)	(\$48,600)
Adjustment for Income taxes		\$262,836	\$388,598	\$323,525
Net Cash Flow (current \$, incl fin.)	(\$2,700,000)	(\$242,041)	(\$115,599)	(\$174,749)
Net Cash Flow (current \$, excl fin.)	(\$4,500,000)	(\$38,124)	\$88,318	\$29,168
Capital Expenditure Annuity @ WACC		(\$624,067)	(\$624,067)	(\$624,067)
NCF with annualized capital		(\$662,191)	(\$535,749)	(\$594,899)
Current \$ /ton of NOx reduced		(\$10,672.96)	(\$8,635.01)	(\$9,588.38)
NCF w/ann cap. Discount by infl rate		(\$645,410)	(\$508,940)	(\$550,809)
Sum of discounted NCF	(\$8,686,939)			
TOTAL Tons NOx reduced Proj. Life	931			
\$/ton NOx reduced (after taxes)	(\$9,334)			
Before Tax Net Cash Flow		(\$925,027)	(\$924,347)	(\$918,424)
Discounted Before Tax NCF		(\$901,585)	(\$878,092)	(\$850,357)
Sum of discounted Before Tax NCF	(\$11,380,334)			
	931			
\$/ton NOx reduced (before tax basis)	(\$12,228)			
Annual Capital Recovery	(\$495,000)			
Annual O&M	(\$233,459)			
Total Annual Cost	(\$728,459)			
Annual NOx reduced (tons)	62			
\$/ton (per ACT document)	(\$11,741)			
Average of both before-tax methods	\$11,985			

NOx Reduction Case Spreadsheet	
Selective Catalytic Reduction - std combustor	
Turbine Technical Data	
Engine Size (MW)	75
Initial NOx value (ppm)	154
Initial NOx massflow (lb/hr)	513.28
NOx reduction needed (up to 40%)	90%
Engine heat rate (BTU/KW hr)	10,000
Outlet NOx Value (ppm)	15.00
Outlet NOx massflow (lb/hr)	50.00
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Heat Rate Increase	0.5%
Cost of Ammonia (\$/ton)	\$360.00
Ammonia Escalation (%/yr.)	2.6%
Catalyst Cost (\$/m3)	\$14,000
Op Hrs Between Catalyst Replacement	42,000
Estimated Fixed O&M in first year	\$20,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital cost, (\$/KW)	\$60
Capital Cost (\$)	\$4,500,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Gas Turbine SCR	
MW	75.0
lb/hr NOx reduced	463.29
lbmole/hr NOx reduced	10.07
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr @ full load	\$1,688
Ammonia Cost (\$/ton)	\$360.00
Ammonia Cost (\$/lbmole)	\$3.06
Ammonia usage (lbmole/hr)	10.1
Ammonia usage (lb/hr)	171.21
Ammonia Cost (\$/hr)	\$30.82
Approx Catalyst Loading (m3)	57
Heat Rate Increase	0.50%
Uncontrolled NOx	154.00
Controlled NOx	15.00
Capital Cost, includes license (\$/KW)	4,500,000
Fixed O&M (\$/yr.)	\$20,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	719

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$12,565,125)	(\$12,891,818)	(\$13,227,006)
Controlled Fuel Cost	\$0	(\$12,628,266)	(\$12,956,601)	(\$13,293,473)
ammonia cost	\$0	(\$95,615)	(\$98,101)	(\$100,651)
annual catalyst addition		(\$142,063)	(\$145,757)	(\$149,547)
Total Variable O&M		(\$300,820)	(\$308,641)	(\$316,666)
Fixed O&M	\$0	(\$20,000)	(\$20,520)	(\$21,054)
Total O&M (incl. Dif. Fuel)	\$0	(\$320,820)	(\$329,161)	(\$337,719)
Total Capital Cost	\$4,500,000			
Financed with Common Equity	(\$2,700,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$1,800,000)			
Debt payments		(\$203,917)	(\$203,917)	(\$203,917)
Interest portion of payment		(\$135,000)	(\$129,831)	(\$124,275)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$450,000)	(\$810,000)	(\$630,000)
EOP Book Value	\$4,500,000	\$4,050,000	\$3,240,000	\$2,610,000
Property Taxes (net of income tax effect)		(\$67,500)	(\$60,750)	(\$48,600)
Adjustment for income taxes		\$293,412	\$419,969	\$355,712
Net Cash Flow (current \$, incl fin.)	(\$2,700,000)	(\$298,825)	(\$173,859)	(\$234,524)
Net Cash Flow (current \$, excl fin.)	(\$4,500,000)	(\$94,908)	\$30,058	(\$30,607)
Capital Expenditure Annuity @ WACC		(\$624,067)	(\$624,067)	(\$624,067)
NCF with annualized capital		(\$718,975)	(\$594,009)	(\$654,675)
Current \$ \$/ton of NOx reduced		(\$1,000.42)	(\$826.54)	(\$910.95)
NCF w/ann cap. Discount by infl rate		(\$700,755)	(\$564,285)	(\$606,155)
Sum of discounted NCF	(\$9,517,118)			
TOTAL Tons NOx reduced Proj. Life	10,780			
\$/ton NOx reduced (after taxes)	(\$883)			
Before Tax Net Cash Flow		(\$1,012,387)	(\$1,013,978)	(\$1,010,386)
Discounted Before Tax NCF		(\$986,732)	(\$963,239)	(\$935,504)
Sum of discounted Before Tax NCF	(\$12,657,532)			
	10,780			
\$/ton NOx reduced (before tax basis)	(\$1,174)			
Annual Capital Recovery	(\$495,000)			
Annual O&M	(\$320,820)			
Total Annual Cost	(\$815,820)			
Annual NOx reduced (tons)	719			
\$/ton (per ACT document)	(\$1,135)			
Average of both before tax methods, \$/ton	\$1,155			

NOx Reduction Case Spreadsheet	
Selective Catalytic Reduction 75 MW GT with diluent injection	
Turbine Technical Data	
Engine Size (MW)	75
Initial NOx value (ppm)	42
Initial NOx massflow (lb/hr)	139.99
NOx reduction needed (up to 40%)	83%
Engine heat rate (BTU/KW hr)	10,000
Outlet NOx Value (ppm)	7.00
Outlet NOx massflow (lb/hr)	23.33
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost (\$/MMBTU)	\$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Heat Rate Increase	0.5%
Cost of Ammonia (\$/ton)	\$360.00
Ammonia Escalation (%/yr.)	2.6%
Catalyst Cost (\$/m3)	\$14,000
Op Hrs Between Catalyst Replacement	42,000
Estimated Fixed O&M in first year	\$20,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital cost, (\$/KW)	\$60
Capital Cost (\$)	\$4,500,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Gas Turbine SCR	
MW	75.0
lb/hr NOx reduced	116.66
lbmole/hr NOx reduced	2.54
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr @ full load	\$1,688
Ammonia Cost (\$/ton)	\$360.00
Ammonia Cost (\$/lbmole)	\$3.06
Ammonia usage (lbmole/hr)	2.5
Ammonia usage (lb/hr)	43.11
Ammonia Cost (\$/hr)	\$7.76
Approx Catalyst Loading (m3)	57
Heat Rate Increase	0.50%
Uncontrolled NOx	42.00
Controlled NOx	7.00
Capital Cost, includes license	4,500,000
Fixed O&M (\$/yr.)	\$20,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	181

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$12,565,125)	(\$12,891,818)	(\$13,227,006)
Controlled Fuel Cost	\$0	(\$12,628,266)	(\$12,956,601)	(\$13,293,473)
ammonia cost	\$0	(\$24,076)	(\$24,702)	(\$25,344)
annual catalyst addition		(\$142,063)	(\$145,757)	(\$149,547)
Total Variable O&M		(\$229,280)	(\$235,242)	(\$241,358)
Fixed O&M	\$0	(\$20,000)	(\$20,520)	(\$21,054)
Total O&M (incl. Dif. Fuel)	\$0	(\$249,280)	(\$255,762)	(\$262,412)
Total Capital Cost	\$4,500,000			
Financed with Common Equity	(\$2,700,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$1,800,000)			
Debt payments		(\$203,917)	(\$203,917)	(\$203,917)
Interest portion of payment		(\$135,000)	(\$129,831)	(\$124,275)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$450,000)	(\$810,000)	(\$630,000)
EOP Book Value	\$4,500,000	\$4,050,000	\$3,240,000	\$2,610,000
Property Taxes (net of income tax effect)		(\$67,500)	(\$60,750)	(\$48,600)
Adjustment for Income taxes		\$268,373	\$394,279	\$329,354
Net Cash Flow (current \$, incl fin.)	(\$2,700,000)	(\$252,324)	(\$126,150)	(\$185,575)
Net Cash Flow (current \$, excl fin.)	(\$4,500,000)	(\$48,407)	\$77,767	\$18,342
Capital Expenditure Annuity @ WACC		(\$624,067)	(\$624,067)	(\$624,067)
NCF with annualized capital		(\$672,475)	(\$546,300)	(\$605,725)
Current \$ /ton of NOx reduced		(\$3,716.13)	(\$3,018.88)	(\$3,347.27)
NCF w/ann cap. Discount by infl rate		(\$655,433)	(\$518,963)	(\$560,833)
Sum of discounted NCF	(\$8,837,286)			
TOTAL Tons NOx reduced Proj. Life	2,714			
\$/ton NOx reduced (after taxes)	(\$3,256)			
Before Tax Net Cash Flow		(\$940,848)	(\$940,579)	(\$935,079)
Discounted Before Tax NCF		(\$917,006)	(\$893,512)	(\$865,777)
Sum of discounted Before Tax NCF	(\$11,611,637)			
	2,714			
\$/ton NOx reduced (before tax basis)	(\$4,278)			
Annual Capital Recovery	(\$495,000)			
Annual O&M	(\$249,280)			
Total Annual Cost	(\$744,280)			
Annual NOx reduced (tons)	181			
\$/ton (per ACT document)	(\$4,113)			
Average of both before-tax methods, \$/ton	\$4,195			

NOx Case Worksheet		
GT-Dry Low NOx: Two Solar Centaur		
Engine Technical Data		
Target Engine Size, (hp)	9,400	two Centaurs
Initial NOx value (ppm)	135	
Initial NOx massflow (lb/hr)	44	
NOx reduction needed (up to 40%)	63%	
Engine heat rate (BTU/KW hr)	7,960	
Outlet NOx Value (ppm)	50.00	
Outlet NOx massflow (lb/hr)	16.11	
Project Economic Data		
# of months/year NOx reduction needed	5	
Capacity Factor	95%	
Primary Fuel Cost (\$/MMBTU)	\$2.25	
Primary Fuel Escalation (%/yr.)	2.6%	
Estimated Fixed O&M in first year	\$15,000	
Labor&Fixed O&M Escalation (%/yr.)	2.6%	
heat rate increase	0.00%	
Capital Cost (\$)	\$1,550,000	
Capital Cost (\$/HP)	\$165	
Cost of Equity Capital (%)	15.0%	
Cost of Debt (%)	7.5%	
Cost of Preferred Equity (%)	6.0%	
% financed with debt (%)	40.0%	
Term of debt financing (years)	15	
% financed with Common Equity	60.0%	
% financed with Preferred Equity	0.0%	
WACC, % (after tax)	11.0%	
WACC, % (before tax)	12.0%	
Income tax rate (%)	35.0%	
Projected inflation rate (%)	2.6%	
Evaluation period of Project (yrs)	15	
Property Tax rate (\$/\$1,000)	\$15.00	
ACT Pretax Marginal Rate of Return	10.0%	

Process Analysis	
Plant	
Nameplate HP	9,400
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr	\$126
Uncontrolled NOx (ppm)	135.00
Controlled NOx	50.00
Capital Cost	\$1,550,000
Fixed O&M (\$/yr.)	\$15,000
Capacity factor	0.95
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	47

		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	\$1,045,177	\$1,072,352	\$1,100,233
Controlled Fuel Cost	\$0	\$1,045,177	\$1,072,352	\$1,100,233
Variable O&M		\$0	\$0	\$0
Fixed O&M	\$0	(\$15,000)	(\$15,390)	(\$15,790)
Total O&M + dif. Fuel	\$0	(\$15,000)	(\$15,390)	(\$15,790)
Total Capital Cost	\$1,550,000			
Financed with Common Equity	(\$930,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$620,000)			
Debt payments		(\$70,238)	(\$70,238)	(\$70,238)
Interest portion of payment		(\$46,500)	(\$44,720)	(\$42,806)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$155,000)	(\$279,000)	(\$217,000)
EOP Book Value	\$1,550,000	\$1,395,000	\$1,116,000	\$899,000
Property Taxes		(\$23,250)	(\$20,925)	(\$16,740)
Adj for income tax effect of depn, oper exp, and prop tax		\$67,638	\$110,360	\$87,336
Net Cash Flow (current \$, incl fin.)	(\$930,000)	(\$40,851)	\$3,807	(\$15,433)
Net Cash Flow (current \$, excl fin.)	(\$1,550,000)	\$29,388	\$74,045	\$54,805
Capital Expenditure Annuity @ WACC		(\$214,956)	(\$214,956)	(\$214,956)
Before Tax Capital Expend Annuity		(\$227,578)	(\$227,578)	(\$227,578)
NCF with annualized capital		(\$185,569)	(\$140,911)	(\$160,151)
Current \$ /ton of NOx reduced		(\$3,907.14)	(\$2,966.87)	(\$3,371.97)
NCF w/ann cap. Discount by infl rate		(\$180,866)	(\$133,860)	(\$148,282)
Sum of discounted NCF	(\$2,370,546)			
TOTAL Tons NOx reduced Proj. Life	712			
\$/ton NOx reduced (after taxes)	(\$3,327)			
Before Tax Net Cash Flow		(\$265,828)	(\$263,893)	(\$260,108)
Discounted Before Tax NCF		(\$259,091)	(\$250,687)	(\$240,830)
Sum of discounted Before Tax NCF	(\$3,118,674)			
	712			
\$/ton NOx reduced (before tax basis)	(\$4,378)			
Annual Capital Recovery	(\$203,784)			
Annual O&M	(\$15,000)			
Total Annual Cost	(\$218,784)			
Annual NOx reduced (tons)	47			
\$/ton (per ACT document)	(\$4,606)	Using method of ACT document		
Average (\$/ton)-both methods	(\$4,492)			

NOx Case Worksheet	
GT-Dry Low NOx: Two Solar Mars 13000	
Engine Technical Data	
Target Engine Size, (hp)	26,000
Initial NOx value (ppm)	167
Initial NOx massflow (lb/hr)	135
NOx reduction needed (up to 40%)	70%
Engine heat rate (BTU/KW hr)	7,960
Final NOx Value (ppm)	50.00
Final NOx massflow (lb/hr)	40.31
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	95%
Primary Fuel Cost (\$/MMBTU)	\$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$15,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	0.00%
Capital Cost (\$)	\$3,900,000
Capital Cost (\$/HP)	\$150
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Before Tax WACC	12.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate HP	26,000
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr	\$347
Uncontrolled NOx (ppm)	167.00
Controlled NOx	50.00
Capital Cost	\$3,900,000
Fixed O&M (\$/yr.)	\$15,000
Capacity factor	0.95
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	392

		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$2,890,916)	(\$2,966,080)	(\$3,043,198)
Controlled Fuel Cost	\$0	(\$2,890,916)	(\$2,966,080)	(\$3,043,198)
Variable O&M		\$0	\$0	\$0
Fixed O&M	\$0	(\$15,000)	(\$15,390)	(\$15,790)
Total O&M + dif. Fuel	\$0	(\$15,000)	(\$15,390)	(\$15,790)
Total Capital Cost	\$3,900,000			
Financed with Common Equity	(\$2,340,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$1,560,000)			
Debt payments		(\$176,728)	(\$176,728)	(\$176,728)
Interest portion of payment		(\$117,000)	(\$112,520)	(\$107,705)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$390,000)	(\$702,000)	(\$546,000)
EOP Book Value	\$3,900,000	\$3,510,000	\$2,808,000	\$2,262,000
Property Taxes		(\$58,500)	(\$52,650)	(\$42,120)
Adj for income tax effect of depn, oper exp, and prop tax		\$162,225	\$269,514	\$211,369
Net Cash Flow (current \$, incl fin.)	(\$2,340,000)	(\$88,003)	\$24,746	(\$23,270)
Net Cash Flow (current \$, excl fin.)	(\$3,900,000)	\$88,725	\$201,474	\$153,458
Capital Expenditure Annuity @ WACC		(\$540,858)	(\$540,858)	(\$540,858)
Before Tax Capital Expend Annuity		(\$572,615)	(\$572,615)	(\$572,615)
NCF with annualized capital		(\$452,133)	(\$339,384)	(\$387,400)
Current \$ /ton of NOx reduced		(\$1,151.98)	(\$864.71)	(\$987.05)
NCF w/ann cap. Discount by infl rate		(\$440,676)	(\$322,401)	(\$358,688)
Sum of discounted NCF	(\$5,748,484)			
TOTAL Tons NOx reduced Proj. Life	5,887			
\$/ton NOx reduced (after taxes)	(\$976)			
Before Tax Net Cash Flow		(\$646,115)	(\$640,655)	(\$630,525)
Discounted Before Tax NCF		(\$629,741)	(\$608,596)	(\$583,795)
Sum of discounted Before Tax NCF	(\$7,514,502)			
	5,887			
\$/ton NOx reduced (before tax basis)	(\$1,276)			
Annual Capital Recovery	(\$512,748)			
Annual O&M	(\$15,000)			
Total Annual Cost	(\$527,748)			
Annual NOx reduced (tons)	392			
\$/ton (per ACT document)	(\$1,345)	Using method of ACT document		
Average (\$/ton)-both methods	(\$1,311)			

NOx Reduction Case Spreadsheet				
Selective Catalytic Reduction				
Turbine Technical Data				
Engine Size (hp)	7,000	HP	5.28	MW
Initial NOx value (ppm)	42			
Initial NOx massflow (lb/hr)	9			
NOx reduction needed (up to 40%)	88%			
Engine heat rate (BTU/KW hr)	11,000			
Outlet NOx Value (ppm)	5.00			
Outlet NOx massflow (lb/hr)	1.11			
Project Economic Data				
# of months/year NOx reduction needed	5			
Capacity Factor	85%			
Primary Fuel Cost (\$/MMBTU)	\$2.25			
Primary Fuel Escalation (%/yr.)	2.6%			
Heat Rate Increase	0.5%			
Cost of Ammonia (\$/ton)	\$360.00			
Ammonia Escalation (%/yr.)	2.6%			
Catalyst Cost (\$/m3)	\$14,000			
Op Hrs Between Catalyst Replacement	42,000			
Estimated Fixed O&M in first year	\$20,000			
Labor&Fixed O&M Escalation (%/yr.)	2.6%			
Capital cost, (\$/KW)	\$225			
Capital Cost (\$)	\$1,174,950			
Cost of Equity Capital (%)	15.0%			
Cost of Debt (%)	7.5%			
Cost of Preferred Equity (%)	6.0%			
% financed with debt (%)	40.0%			
Term of debt financing (years)	15			
% financed with Common Equity	60.0%			
% financed with Preferred Equity	0.0%			
WACC, %	11.0%			
Before Tax WACC	12.0%			
Income tax rate (%)	35.0%			
Projected inflation rate (%)	2.6%			
Evaluation period of Project (yrs)	15			
Property Tax rate (\$/\$1,000)	\$15.00			
ACT pretax marginal rate of return	10.0%			

Process Analysis	
Gas Turbine SCR	
MW	7,000.0
lb/hr NOx reduced	8.22
lbmole/hr NOx reduced	0.18
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr @ full load	\$129
Ammonia Cost (\$/ton)	\$360.00
Ammonia Cost (\$/lbmole)	\$3.06
Ammonia usage (lbmole/hr)	0.2
Ammonia usage (lb/hr)	3.04
Ammonia Cost (\$/hr)	\$0.55
Approx Catalyst Loading (m3)	16
Heat Rate Increase	0.50%
Uncontrolled NOx	42.00
Controlled NOx	5.00
Capital Cost, includes license (\$/KW)	1,174,950
Fixed O&M (\$/yr.)	\$20,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	13

	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$962,355)	(\$987,376)	(\$1,013,048)
Controlled Fuel Cost	\$0	(\$967,190)	(\$992,337)	(\$1,018,138)
ammonia cost	\$0	(\$1,696)	(\$1,740)	(\$1,786)
annual catalyst addition		(\$40,835)	(\$41,896)	(\$42,986)
Total Variable O&M		(\$47,367)	(\$48,598)	(\$49,862)
Fixed O&M	\$0	(\$20,000)	(\$20,520)	(\$21,054)
Total O&M (incl. dif. Fuel)	\$0	(\$67,367)	(\$69,118)	(\$70,915)
Total Capital Cost	\$1,174,950			
Financed with Common Equity	(\$704,970)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$469,980)			
Debt payments		(\$53,243)	(\$53,243)	(\$53,243)
Interest portion of payment		(\$35,249)	(\$33,899)	(\$32,448)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$117,495)	(\$211,491)	(\$164,493)
EOP Book Value	\$1,174,950	\$1,057,455	\$845,964	\$681,471
Property Taxes (net of income tax effect)		(\$17,624)	(\$15,862)	(\$12,689)
Adj for income tax effect of depn, prop tax, oper exp		\$70,870	\$103,765	\$86,834
Net Cash Flow (current \$, incl fin.)	(\$704,970)	(\$67,364)	(\$34,458)	(\$50,013)
Net Cash Flow (current \$, excl fin.)	(\$1,174,950)	(\$14,121)	\$18,785	\$3,229
Capital Expenditure Annuity @ WACC		(\$162,944)	(\$162,944)	(\$162,944)
Before Tax Capital Expenditure Annuity		(\$172,511)	(\$172,511)	(\$172,511)
NCF with annualized capital		(\$177,065)	(\$144,159)	(\$159,715)
Current \$ \$/ton of NOx reduced		(\$13,887.26)	(\$11,306.46)	(\$12,526.47)
NCF w/ann cap. discount by infl rate		(\$172,578)	(\$136,945)	(\$147,878)
Sum of discounted NCF	(\$2,329,079)			
TOTAL Tons NOx reduced Proj. Life	191			
\$/ton NOx reduced (after taxes)	(\$12,178)			
Before Tax Net Cash Flow		(\$257,502)	(\$257,491)	(\$256,116)
Discounted Before Tax NCF		(\$250,977)	(\$244,606)	(\$237,134)
Sum of discounted Before Tax NCF	(\$3,182,715)			
	191			
\$/ton NOx reduced (before tax basis)	\$16,641			
Annual Capital Recovery	(\$129,245)			
Annual O&M	(\$67,367)			
Total Annual Cost	(\$196,611)			
Annual NOx reduced (tons)	13			
\$/ton (per ACT document)	(\$15,420)	Consistent with method of ACT document		
	\$16,031		Average	

Reciprocating Internal Combustion Engine Worksheets

NOx Case Worksheet	
Clean Burn-IC - med speed: four 2,500 hp engines	
Engine Technical Data	
Target Engine Size	10,000
Initial NOx value (gm/hp-hr)	15
NOx reduction needed (up to 40%)	80%
Engine heat rate (BTU/KW-hr)	7,500
Outlet NOx Value	3.00
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	45%
Primary Fuel Cost (\$/MMBTU)	\$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$8,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	-1.00%
Capital Cost (\$)	\$2,000,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate HP	10,000
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr	\$126
Uncontrolled NOx	15.00
Controlled NOx	3.00
Capital Cost, includes license (\$/KW)	2,000,000
Fixed O&M (\$/yr.)	\$8,000
Capacity factor	0.45
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	217

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$496,249)	(\$509,151)	(\$522,389)
Controlled Fuel Cost	\$0	(\$491,286)	(\$504,059)	(\$517,165)
Variable O&M		\$4,962	\$5,092	\$5,224
Fixed O&M	\$0	(\$8,000)	(\$8,208)	(\$8,421)
Total O&M + dif. Fuel	\$0	(\$3,038)	(\$3,116)	(\$3,198)
Total Capital Cost	\$2,000,000			
Financed with Common Equity	(\$1,200,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$800,000)			
Debt payments		(\$90,630)	(\$90,630)	(\$90,630)
Interest portion of payment		(\$60,000)	(\$57,703)	(\$55,233)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$200,000)	(\$360,000)	(\$280,000)
EOP Book Value	\$2,000,000	\$1,800,000	\$1,440,000	\$1,160,000
Property Taxes		(\$30,000)	(\$27,000)	(\$21,600)
Adjustment for Income taxes		\$81,563	\$136,541	\$106,679
Net Cash Flow (current \$, incl fin.)	(\$1,200,000)	(\$42,104)	\$15,794	(\$8,748)
Net Cash Flow (current \$, excl fin.)	(\$2,000,000)	\$48,526	\$106,424	\$81,882
Capital Expenditure Annuity @ WACC		(\$277,363)	(\$277,363)	(\$277,363)
NCF with annualized capital		(\$228,838)	(\$170,939)	(\$195,482)
Current \$ /ton of NOx reduced		(\$1,054.21)	(\$787.48)	(\$900.54)
NCF w/ann cap. discount by infl rate		(\$223,039)	(\$162,385)	(\$180,994)
Sum of discounted NCF	(\$2,903,706)			
TOTAL Tons NOx reduced Proj. Life	3,256			
\$/ton NOx reduced (after taxes)	(\$892)			
Before Tax Net Cash Flow		(\$310,401)	(\$307,480)	(\$302,161)
Discounted Before Tax NCF		(\$302,535)	(\$292,093)	(\$279,767)
Sum of discounted Before Tax NCF	(\$3,585,379)			
	3,256			
\$/ton NOx reduced (before tax basis)	(\$1,101)			
Annual Capital Recovery	(\$220,000)			
Annual O&M	(\$3,038)			
Total Annual Cost	(\$223,038)			
Annual NOx reduced (tons)	217			
\$/ton (per ACT document)	(\$1,027)			
Average of both before tax methods	(\$1,064)			

NOx Case Worksheet	
Clean Burn-IC, four 2,500 hp dual fuel engines	
Engine Technical Data	
Target Engine Size	10,000
Initial NOx value (gm/hp-hr)	15
NOx reduction needed (up to 40%)	87%
Engine heat rate (BTU/KW-hr)	7,000
Outlet NOx Value	2.00
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	45%
Primary Fuel Cost (\$/MMBTU)	\$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$8,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	0.00%
Capital Cost (\$)	\$6,200,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate HP	10,000
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr	\$117
Uncontrolled NOx	15.00
Controlled NOx	2.00
Capital Cost, includes license (\$/KW)	6,200,000
Fixed O&M (\$/yr.)	\$8,000
Capacity factor	0.45
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	564

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$463,165)	(\$475,208)	(\$487,563)
Controlled Fuel Cost	\$0	(\$463,165)	(\$475,208)	(\$487,563)
Variable O&M		\$0	\$0	\$0
Fixed O&M	\$0	(\$8,000)	(\$8,208)	(\$8,421)
Total O&M + dif. Fuel	\$0	(\$8,000)	(\$8,208)	(\$8,421)
Total Capital Cost	\$6,200,000			
Financed with Common Equity	(\$3,720,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$2,480,000)			
Debt payments		(\$280,952)	(\$280,952)	(\$280,952)
Interest portion of payment		(\$186,000)	(\$178,879)	(\$171,223)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$620,000)	(\$1,116,000)	(\$868,000)
EOP Book Value	\$6,200,000	\$5,580,000	\$4,464,000	\$3,596,000
Property Taxes		(\$93,000)	(\$83,700)	(\$66,960)
Adjustment for income taxes		\$252,350	\$422,768	\$330,183
Net Cash Flow (current \$, incl fin.)	(\$3,720,000)	(\$129,602)	\$49,907	(\$26,150)
Net Cash Flow (current \$, excl fin.)	(\$6,200,000)	\$151,350	\$330,860	\$254,802
Capital Expenditure Annuity @ WACC		(\$859,826)	(\$859,826)	(\$859,826)
NCF with annualized capital		(\$708,476)	(\$528,966)	(\$605,024)
Current \$ /ton of NOx reduced		(\$1,255.31)	(\$937.25)	(\$1,072.01)
NCF w/ann cap. discount by infl rate		(\$690,522)	(\$502,497)	(\$560,184)
Sum of discounted NCF	(\$8,988,031)			
TOTAL Tons NOx reduced Proj. Life	8,466			
\$/ton NOx reduced (after taxes)	(\$1,062)			
Before Tax Net Cash Flow		(\$960,826)	(\$951,734)	(\$935,207)
Discounted Before Tax NCF		(\$936,478)	(\$904,109)	(\$865,896)
Sum of discounted Before Tax NCF	(\$11,093,970)			
	8,466			
\$/ton NOx reduced (before tax basis)	(\$1,310)			
Annual Capital Recovery	(\$682,000)			
Annual O&M	(\$8,000)			
Total Annual Cost	(\$690,000)			
Annual NOx reduced (tons)	564			
\$/ton (per ACT document)	(\$1,223)			
Average of both before tax methods	(\$1,267)			

NOx Case Worksheet	
Clean Burn-IC: two low speed 3400 hp engines	
Engine Technical Data	
Target Engine Size	6,800
Initial NOx value (gm/hp-hr)	13
NOx reduction needed (up to 40%)	77%
Engine heat rate (BTU/KW-hr)	7,500
Outlet NOx Value (gm/hp-hr)	2.99
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	45%
Primary Fuel Cost (\$/MMBTU)	\$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$8,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	0.50%
Capital Cost (\$)	\$2,328,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate HP	6,800
Pri. Fuel Cost, \$/MMBTU	\$2.25
Pri. Fuel Cost, \$/hr	\$86
Uncontrolled NOx	13.00
Controlled NOx	2.99
Capital Cost, includes license (\$/KW)	2,328,000
Fixed O&M (\$/yr.)	\$8,000
Capacity factor	0.45
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	123

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	(\$337,449)	(\$346,223)	(\$355,224)
Controlled Fuel Cost	\$0	(\$339,136)	(\$347,954)	(\$357,001)
Variable O&M		(\$1,687)	(\$1,731)	(\$1,776)
Fixed O&M	\$0	(\$8,000)	(\$8,208)	(\$8,421)
Total O&M + dif. Fuel	\$0	(\$9,687)	(\$9,939)	(\$10,198)
Total Capital Cost	\$2,328,000			
Financed with Common Equity	(\$1,396,800)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$931,200)			
Debt payments		(\$105,493)	(\$105,493)	(\$105,493)
Interest portion of payment		(\$69,840)	(\$67,166)	(\$64,291)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$232,800)	(\$419,040)	(\$325,920)
EOP Book Value	\$2,328,000	\$2,095,200	\$1,676,160	\$1,350,240
Property Taxes		(\$34,920)	(\$31,428)	(\$25,142)
Adjustment for Income taxes		\$97,093	\$161,142	\$126,441
Net Cash Flow (current \$, incl fin.)	(\$1,396,800)	(\$53,008)	\$14,282	(\$14,392)
Net Cash Flow (current \$, excl fin.)	(\$2,328,000)	\$52,485	\$119,775	\$91,101
Capital Expenditure Annuity @ WACC		(\$322,851)	(\$322,851)	(\$322,851)
NCF with annualized capital		(\$270,366)	(\$203,075)	(\$231,750)
Current \$ /ton of NOx reduced		(\$2,195.78)	(\$1,649.28)	(\$1,882.16)
NCF w/ann cap. discount by infl rate		(\$263,514)	(\$192,914)	(\$214,574)
Sum of discounted NCF	(\$3,438,372)			
TOTAL Tons NOx reduced Proj. Life	1,847			
\$/ton NOx reduced (after taxes)	(\$1,862)			
Before Tax Net Cash Flow		(\$367,458)	(\$364,218)	(\$358,191)
Discounted Before Tax NCF		(\$358,146)	(\$345,992)	(\$331,644)
Sum of discounted Before Tax NCF	(\$4,263,317)			
	1,847			
\$/ton NOx reduced (before tax basis)	(\$2,308)			
Annual Capital Recovery	(\$256,080)			
Annual O&M	(\$9,687)			
Total Annual Cost	(\$265,767)			
Annual NOx reduced (tons)	123			
\$/ton (per ACT document)	(\$2,158)			
average of both before tax methods	(\$2,233)			

NOx Reduction Case Spreadsheet		
Selective Catalytic Reduction	SCR on diesel	
IC Engine Technical Data		
Engine Size (HP)	9390	
Initial NOx value (gm/hp-hr)	10	
Initial NOx massflow (lb/hr)	206.8	
NOx reduction needed (up to 90%)	90%	
Outlet NOx Value (gm/hp-hr)	1.00	
Outlet NOx massflow (lb/hr)	20.7	
Project Economic Data		
# of months/year NOx reduction needed	5	
Capacity Factor	85%	
Primary Fuel Cost (\$/MMBTU)	\$5.00	
Primary Fuel Escalation (%/yr.)	2.6%	
Heat Rate (BTU/HP-hr)	5,600	
Heat Rate Increase	0.5%	
Cost of Ammonia (\$/ton)	\$360.00	
Ammonia Escalation (%/yr.)	2.6%	
Catalyst Cost (\$/m3)	\$14,000	
Catalyst Volume (ft3)	84	
Layers of Cat	1	
Op Hrs Between Catalyst Replacement	24,000	between layer change
Estimated Fixed O&M in first year	\$23,600	
Labor&Fixed O&M Escalation (%/yr.)	2.6%	
Capital cost (\$/hp)	\$109	
Capital Cost (\$)	\$1,022,220	
Cost of Equity Capital (%)	15.0%	
Cost of Debt (%)	7.5%	
Cost of Preferred Equity (%)	6.0%	
% financed with debt (%)	40.0%	
Term of debt financing (years)	15	
% financed with Common Equity	60.0%	
% financed with Preferred Equity	0.0%	
WACC, %	11.0%	
Before Tax WACC	12.0%	
Income tax rate (%)	35.0%	
Projected inflation rate (%)	2.6%	
Evaluation period of Project (yrs)	15	
Property Tax rate (\$/\$1,000)	\$15.00	
ACT pretax marginal rate of return	10.0%	

Process Analysis	
HP	9,390.0
lb/hr NOx reduced	186.15
lbmole/hr NOx reduced	4.05
Pri. Fuel Cost, \$/MMBTU	\$5.00
Pri. Fuel Cost, \$/hr	\$263
Ammonia Cost (\$/ton)	\$360.00
Ammonia Cost (\$/lbmole)	\$3.06
Ammonia usage (lbmole/hr)	4.0
Ammonia usage (lb/hr)	68.79
Ammonia Cost (\$/hr)	\$12.38
Approx Catalyst Loading (m3)	2.4
Heat Rate Increase	0.50%
Uncontrolled NOx	10.00
Controlled NOx	1.00
Capital Cost, includes license (\$/KW)	1,022,220
Fixed O&M (\$/yr.)	\$23,600
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	289

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	\$815,709	\$836,918	\$858,678
Controlled Fuel Cost	\$0	\$819,808	\$841,123	\$862,993
ammonia cost	\$0	(\$38,417)	(\$39,416)	(\$40,441)
annual catalyst addition		(\$3,475)	(\$3,565)	(\$3,658)
Total Variable O&M		(\$37,793)	(\$38,776)	(\$39,784)
Fixed O&M	\$0	(\$23,600)	(\$24,214)	(\$24,843)
Total O&M (incl. dif. Fuel)	\$0	(\$61,393)	(\$62,989)	(\$64,627)
Total Capital Cost	\$1,022,220			
Financed with Common Equity	(\$613,332)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$408,888)			
Debt payments		(\$46,322)	(\$46,322)	(\$46,322)
Interest portion of payment		(\$30,667)	(\$29,492)	(\$28,230)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$102,222)	(\$184,000)	(\$143,111)
EOP Book Value	\$1,022,220	\$919,998	\$735,998	\$592,888
Property Taxes (net of income tax effect)		(\$15,333)	(\$13,800)	(\$11,040)
Income tax adj for prop tax, depn, oper exp		\$62,632	\$91,276	\$76,572
Net Cash Flow (current \$, incl fin.)	(\$613,332)	(\$60,416)	(\$31,835)	(\$45,417)
Net Cash Flow (current \$, excl fin.)	(\$1,022,220)	(\$14,094)	\$14,487	\$905
Capital Expenditure Annuity @ WACC		(\$141,763)	(\$141,763)	(\$141,763)
Before Tax Capital Exp Ann		(\$141,763)	(\$141,763)	(\$141,763)
NCF with annualized capital		(\$155,858)	(\$127,276)	(\$140,858)
Current \$ /ton of NOx reduced		(\$539.75)	(\$440.77)	(\$487.81)
NCF w/ann cap. discount by infl rate		(\$151,908)	(\$120,907)	(\$130,418)
Sum of discounted NCF	(\$2,052,774)			
TOTAL Tons NOx reduced Proj. Life	4,331			
\$/ton NOx reduced (after taxes)	(\$474)			
Before Tax Net Cash Flow		(\$218,490)	(\$218,552)	(\$217,430)
Discounted Before Tax NCF		(\$212,953)	(\$207,616)	(\$201,316)
Sum of discounted Before Tax NCF	(\$2,707,386)			
	4,331			
\$/ton NOx reduced (before tax basis)	(\$625)			
Annual Capital Recovery	(\$112,444)			
Annual O&M	(\$61,393)			
Total Annual Cost	(\$173,837)			
Annual NOx reduced (tons)	289			
\$/ton (per ACT document)	(\$602.02)	Consistent with method of ACT document		
	\$614			

NOx Reduction Case Spreadsheet		
Selective Catalytic Reduction		large lean burn engine
IC Engine Technical Data		
Engine Size (HP)	9390	one engine
Initial NOx value (gm/hp-hr)	10	
Initial NOx massflow (lb/hr)	206.8	
NOx reduction needed (up to 90%)	90%	
Outlet NOx Value (gm/hp-hr)	1.00	
Outlet NOx massflow (lb/hr)	20.7	
Project Economic Data		
# of months/year NOx reduction needed	5	
Capacity Factor	85%	
Primary Fuel Cost (\$/MMBTU)	\$2.25	
Primary Fuel Escalation (%/yr.)	2.6%	
Heat Rate (BTU/HP-hr)	5,600	
Heat Rate Increase	0.5%	
Cost of Ammonia (\$/ton)	\$360.00	
Ammonia Escalation (%/yr.)	2.6%	
Catalyst Cost (\$/m3)	\$14,000	
Catalyst Volume (ft3)	63	
Layers of cat	1	
Op Hrs Between Catalyst Replacement	24,000	between layer change
Estimated Fixed O&M in first year	\$23,600	
Labor&Fixed O&M Escalation (%/yr.)	2.6%	
Capitall cost (\$/hp)	\$97	
Capital Cost (\$)	\$907,653	
Cost of Equity Capital (%)	15.0%	
Cost of Debt (%)	7.5%	
Cost of Preferred Equity (%)	6.0%	
% financed with debt (%)	40.0%	
Term of debt financing (years)	15	
% financed with Common Equity	60.0%	
% financed with Preferred Equity	0.0%	
WACC, %	11.0%	
Before Tax WACC	12.0%	
Income tax rate (%)	35.0%	
Projected inflation rate (%)	2.6%	
Evaluation period of Project (yrs)	15	
Property Tax rate (\$/\$1,000)	\$15.00	
ACT pretax marginal rate of return	10.0%	
Process Analysis		
Lean IC SCR		
HP	9,390.0	
lb/hr NOx reduced	186.15	
lbmole/hr NOx reduced	4.05	
Pri. Fuel Cost, \$/MMBTU	\$2.25	
Pri. Fuel Cost, \$/hr	\$118	
Ammonia Cost (\$/ton)	\$360.00	
Ammonia Cost (\$/lbmole)	\$3.06	
Ammonia usage (lbmole/hr)	4.0	
Ammonia usage (lb/hr)	68.79	
Ammonia Cost (\$/hr)	\$12.38	
Approx Catalyst Loading (m3)	1.8	
Heat Rate Increase	0.50%	
Uncontrolled NOx	10.00	
Controlled NOx	1.00	
Capital Cost, includes license (\$/KW)	907,653	
Fixed O&M (\$/yr.)	\$23,600	
Capacity factor	0.85	
Months NOx reduction in service	5.00	
Projected Book Life, yrs	15.00	
Ann. NOx Red'n, tons	289	

	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	\$367,069	\$376,613	\$386,405
Controlled Fuel Cost	\$0	\$368,914	\$378,506	\$388,347
ammonia cost	\$0	(\$38,417)	(\$39,416)	(\$40,441)
annual catalyst addition		(\$7,818)	(\$8,022)	(\$8,230)
Total Variable O&M		(\$44,391)	(\$45,545)	(\$46,729)
Fixed O&M	\$0	(\$23,600)	(\$24,214)	(\$24,843)
Total O&M (incl. dif. Fuel)	\$0	(\$67,991)	(\$69,759)	(\$71,573)
Total Capital Cost	\$907,653			
Financed with Common Equity	(\$544,592)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$363,061)			
Debt payments		(\$41,130)	(\$41,130)	(\$41,130)
Interest portion of payment		(\$27,230)	(\$26,187)	(\$25,066)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$90,765)	(\$163,378)	(\$127,071)
EOP Book Value	\$907,653	\$816,888	\$653,510	\$526,439
Property Taxes (net of income tax effect)		(\$13,615)	(\$12,253)	(\$9,803)
Income tax adj for prop tax, depn, oper exp		\$60,330	\$85,886	\$72,956
Net Cash Flow (current \$, incl fin.)	(\$544,592)	(\$62,406)	(\$37,256)	(\$49,549)
Net Cash Flow (current \$, excl fin.)	(\$907,653)	(\$21,276)	\$3,874	(\$8,419)
Capital Expenditure Annuity @ WACC		(\$125,875)	(\$125,875)	(\$125,875)
Before Tax Capital Exp Ann		(\$125,875)	(\$125,875)	(\$125,875)
NCF with annualized capital		(\$147,151)	(\$122,001)	(\$134,294)
Current \$ /ton of NOx reduced		(\$509.60)	(\$422.50)	(\$465.07)
NCF w/ann cap. discount by infl rate		(\$143,422)	(\$115,896)	(\$124,341)
Sum of discounted NCF	(\$1,950,793)			
TOTAL Tons NOx reduced Proj. Life	4,331			
\$/ton NOx reduced (after taxes)	(\$450)			
Before Tax Net Cash Flow		(\$207,481)	(\$207,887)	(\$207,250)
Discounted Before Tax NCF		(\$202,223)	(\$197,484)	(\$191,890)
Sum of discounted Before Tax NCF	(\$2,601,009)			
\$/ton NOx reduced (before tax basis)	(\$601)			
Annual Capital Recovery	(\$99,842)			
Annual O&M	(\$67,991)			
Total Annual Cost	(\$167,833)			
Annual NOx reduced (tons)	289			
\$/ton (per ACT document)	(\$581.22)	Consistent with method of ACT document		

\$591

NOx Reduction Case Spreadsheet	
Selective Catalytic Reduction	ARIS 2000 on Diesel
IC Engine Technical Data	
Engine Size (HP)	1971
Initial NOx value (gm/hp-hr)	15
Initial NOx massflow (lb/hr)	65.1
NOx reduction needed (up to 90%)	75%
Outlet NOx Value (gm/hp-hr)	3.75
Outlet NOx massflow (lb/hr)	16.3
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	10%
Primary Fuel Cost (\$/MMBTU)	\$5.00
Primary Fuel Escalation (%/yr.)	2.6%
Heat Rate (BTU/HP-hr)	5,600
Heat Rate Increase	0.5%
32.5% Urea Solution Cost (\$/gallon)	\$0.86
Cost of Urea (\$/lb)	\$0.29
Ammonia Escalation (%/yr.)	2.6%
Catalyst Cost (\$/ft3)	\$1,500
Catalyst Volume (ft3)	8.76
Op Hrs Between Catalyst Replacement	24,000
Estimated Fixed O&M in first year	\$2,500
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital cost (\$/hp)	\$41
Capital Cost (\$)	\$80,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Before Tax WACC	12.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
ACT pretax marginal rate of return	10.0%
Process Analysis	
Diesel SCR :ARIS 2000	
HP	1,971.0
lb/hr NOx reduced	48.84
lbmole/hr NOx reduced	1.06
Pri. Fuel Cost, \$/MMBTU	\$5.00
Pri. Fuel Cost, \$/hr	\$55
Urea Cost (\$/lb)	\$0.29
Urea Cost (\$/lbmole)	\$17.64
Urea Usage (lbmole/hr)	0.53
Urea Usage (lb/hr)	31.85
Urea Cost (\$/hr)	\$9.37
Approx Catalyst Loading (m3)	0.25
Heat Rate Increase	0.50%
Uncontrolled NOx	15.00
Controlled NOx	3.75
Capital Cost, includes license (\$/KW)	80,000
Fixed O&M (\$/yr.)	\$2,500
Capacity factor	0.10
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	21

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	\$0	\$48,345	\$49,602	\$50,891
Controlled Fuel Cost	\$0	\$48,588	\$49,851	\$51,147
Urea Cost	\$0	(\$8,204)	(\$8,417)	(\$8,636)
annual catalyst addition		(\$480)	(\$492)	(\$505)
Total Variable O&M		(\$8,441)	(\$8,660)	(\$8,885)
Fixed O&M	\$0	(\$2,500)	(\$2,565)	(\$2,632)
Total O&M (incl. dif. Fuel)	\$0	(\$10,941)	(\$11,225)	(\$11,517)
Total Capital Cost				
	\$80,000			
Financed with Common Equity	(\$48,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$32,000)			
Debt payments		(\$3,625)	(\$3,625)	(\$3,625)
Interest portion of payment		(\$2,400)	(\$2,308)	(\$2,209)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$8,000)	(\$14,400)	(\$11,200)
EOP Book Value	\$80,000	\$72,000	\$57,600	\$46,400
Property Taxes (net of income tax effect)		(\$1,200)	(\$1,080)	(\$864)
Income Tax Adj for prop tax, depn, oper exp		\$7,049	\$9,347	\$8,253
Net Cash Flow (current \$, incl fin.)	(\$48,000)	(\$8,717)	(\$6,583)	(\$7,753)
Net Cash Flow (current \$, excl fin.)	(\$80,000)	(\$5,091)	(\$2,958)	(\$4,128)
Capital Expenditure Annuity @ WACC		(\$11,095)	(\$11,095)	(\$11,095)
Before Tax Cap Exp Ann		(\$11,746)	(\$11,746)	(\$11,746)
NCF with annualized capital		(\$16,186)	(\$14,053)	(\$15,222)
Current \$ /ton of NOx reduced		(\$756.62)	(\$656.91)	(\$711.57)
NCF w/ann cap. discount by infl rate		(\$15,776)	(\$13,350)	(\$14,094)
Sum of discounted NCF	(\$218,962)			
TOTAL Tons NOx reduced Proj. Life	321			
\$/ton NOx reduced (after taxes)	(\$682)			
Before Tax Net Cash Flow		(\$23,887)	(\$24,051)	(\$24,127)
Discounted Before Tax NCF		(\$23,281)	(\$22,848)	(\$22,339)
Sum of discounted Before Tax NCF	(\$309,596)			
	321			
\$/ton NOx reduced (before tax basis)	(\$965)			
Annual Capital Recovery	(\$8,800)			
Annual O&M	(\$10,941)			
Total Annual Cost	(\$19,741)			
Annual NOx reduced (tons)	21			
\$/ton (per ACT document)	(\$922.79)	Consistent with method of ACT document		
	\$944			

Cement Kiln Worksheets

NOx Reduction Case Spreadsheet		
KILN - Combustion CemStar		
Kiln Technical Data		
Target Kiln Size (TPH clinker)	160	four kilns of 40 TPH Each
Initial NOx value (pph)	800	
Initial NOx value (lb/ton clinker)	5.00	
NOx reduction needed (up to 40%)	20%	
Outlet NOx Value (pph)	640	
Outlet NOx Value (lb/ton clinker)	3.70	
Project Economic Data		
# of months/year NOx reduction needed	5	
Capacity Factor	45%	
Net Clinker Value (\$/ton)	\$15	
Heat Input Rate (MMBTU/ton clinker)	6.00	
Primary Fuel Cost (\$/MMBTU)	\$1.50	
Primary Fuel Escalation (%/yr.)	2.6%	
Secondary Fuel Cost (\$/MMBTU)	\$2.25	
Secondary Fuel Escalation (%/yr.)	2.6%	
Fuel cost Change	-1.0%	
Slag Fee (\$/ton)	\$16.00	
Slag Feed Rate (ton/hr)	13	for all four kilns
ton clinker/ton slag	1.0	
Estimated Fixed O&M in first year	\$100,000	
Labor&Fixed O&M Escalation (%/yr.)	2.6%	
Capital Cost (\$)	\$1,000,000	
Cost of Equity Capital (%)	15.0%	
Cost of Debt (%)	7.5%	
Cost of Preferred Equity (%)	6.0%	
% financed with debt (%)	40.0%	
Term of debt financing (years)	15	
% financed with Common Equity	60.0%	
% financed with Preferred Equity	0.0%	
WACC, %	11.0%	
Before Tax WACC	12.0%	
Income tax rate (%)	35.0%	
Projected inflation rate (%)	2.6%	
Evaluation period of Project (yrs)	15	
Property Tax rate (\$/\$1,000)	\$15.00	
Pretax Rate of Return (ACT document)	10.0%	

Process Analysis	KILN - Combustion
Plant	
TPH clinker	160
lb/hr NOx reduced	160
lbmole/hr NOx reduced	3
Heat Input (MMBTU/hr)	960
Fuel Cost (without NOx control)	\$9
Fuel Cost (with NOx control)	\$9
Fuel Cost Change	(\$0)
Uncontrolled NOx	800.00
Controlled NOx	640.00
Capital Cost, includes license (\$/KW)	1,000,000
Fixed O&M (\$/yr.)	\$25,000
Capacity factor	0.45
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	131

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
KILN - Combustion Cemstar		Year		
	0	1	2	3
Operating Costs				
Include Fuel Cost Effect (y / n)	y			
Misc Var O&M		(\$20,000)	(\$20,520)	(\$20,520)
Change in Fuel Cost		\$148	\$152	\$152
Additional Cost for Slag Addition	\$0	(\$832,550)	(\$854,197)	(\$854,197)
Value of additional production		\$780,516	\$800,809	\$800,809
Total Variable O&M		(\$52,034)	(\$53,387)	(\$53,387)
Fixed O&M	\$0	(\$10,000)	(\$10,260)	(\$10,527)
Total O&M	\$0	(\$62,034)	(\$63,647)	(\$63,914)
Total Capital Cost	\$1,000,000			
Financed with Common Equity	(\$600,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$400,000)			
Debt payments		(\$45,315)	(\$45,315)	(\$45,315)
Interest portion of payment		(\$30,000)	(\$28,851)	(\$27,617)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$100,000)	(\$180,000)	(\$140,000)
EOP Book Value	\$1,000,000	\$900,000	\$720,000	\$580,000
Property Taxes		(\$15,000)	(\$13,500)	(\$10,800)
income tax adj for prop tax, depn, oper exp		\$61,962	\$90,002	\$75,150
Net Cash Flow (current \$, incl fin.)	(\$600,000)	(\$60,387)	(\$32,461)	(\$44,879)
Net Cash Flow (current \$, excl fin.)	(\$1,000,000)	(\$15,072)	\$12,854	\$436
Capital Expenditure Annuity @ WACC		(\$138,682)	(\$138,682)	(\$138,682)
Before Tax Cap Exp Ann		(\$146,824)	(\$146,824)	(\$146,824)
NCF with annualized capital		(\$153,754)	(\$125,827)	(\$138,246)
Current \$ /ton of NOx reduced		(\$1,170.12)	(\$957.59)	(\$1,052.10)
NCF w/ann cap. discount by infl rate		(\$149,858)	(\$119,531)	(\$128,000)
Sum of discounted NCF	(\$1,958,104)			
TOTAL Tons NOx reduced Proj. Life	1,971			
\$/ton NOx reduced (after taxes)	(\$993)			
Total Tons Clinker over project life	9,460,800			
\$/ton clinker	(\$0.21)			
Before Tax Net Cash Flow		(\$223,859)	(\$223,972)	(\$221,538)
Discounted Before Tax NCF		(\$218,186)	(\$212,764)	(\$205,119)
Sum of discounted Before Tax NCF	(\$2,671,617)			
TOTAL Tons NOx reduced Proj. Life	1,971			
\$/ton NOx reduced (before tax basis)	(\$1,355)			
\$/ton clinker	(\$0.28)			
Annual Capital Recovery	(\$110,000)			
Annual O&M	(\$62,034)			
Total Cost	(\$172,034)			
Annual NOx reduced (tons)	131			
\$/ton (per ACT document)	(\$1,309)	Consistent with method of ACT document		
\$/ton clinker	(\$0.27)	average		
	\$1,332			
	\$0.28			

NOx Reduction Case Spreadsheet			
KILN - Combustion - Mid Kiln Firing			
Kiln Technical Data			
Target Kiln Size (TPH clinker)	80	two 40 TPH kilns	
Initial NOx value (pph)	400		
Initial NOx value (lb/ton clinker)	5.00		
NOx reduction needed	20%		
Outlet NOx Value (pph)	320		
Outlet NOx Value (lb/ton clinker)	4.00		
Project Economic Data			
# of months/year NOx reduction needed	12		
Capacity Factor	85%		
Tipping Fee, \$/ton of tires	\$75		
Heat Input Rate (MMBTU/ton clinker)	4.50	% normally	% with NOx reduction
Primary Fuel Cost (\$/MMBTU)	\$1.50	100%	80%
Primary Fuel Escalation (%/yr.)	2.6%		
Secondary Fuel Cost (\$/MMBTU)	\$2.25	0%	0%
Secondary Fuel Escalation (%/yr.)	2.6%		
Tires Cost, \$/MMBTU	-\$2.68	0%	20%
Tires escalation	2.6%		
Estimated Fixed O&M in first year	\$64,000		
Labor&Fixed O&M Escalation (%/yr.)	2.6%		
Capital Cost (\$)	\$1,495,000		
Cost of Equity Capital (%)	15.0%		
Cost of Debt (%)	7.5%		
Cost of Preferred Equity (%)	6.0%		
% financed with debt (%)	40.0%		
Term of debt financing (years)	15		
% financed with Common Equity	60.0%		
% financed with Preferred Equity	0.0%		
WACC, %	11.0%		
Before Tax WACC	12.0%		
Income tax rate (%)	35.0%		
Projected inflation rate (%)	2.6%		
Evaluation period of Project (yrs)	15		
Property Tax rate (\$/\$1,000)	\$15.00		
Pretax Rate of Return (ACT document)	10.0%		

Process Analysis	KILN - Combustion - Mid Kiln Firing
Plant	
TPH clinker	80
lb/hr NOx reduced	80
lbmole/hr NOx reduced	2
Heat Input (MMBTU/hr)	360
Fuel Cost (without NOx control)	\$540
Fuel Cost (with NOx control)	\$239
Fuel Cost Change	(\$301)
Uncontrolled NOx	400.00
Controlled NOx	320.00
Capital Cost, includes license (\$/KW)	1,495,000
Fixed O&M (\$/yr.)	\$25,000
Capacity factor	0.85
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	298

KILN - Combustion - Mid Kiln Firing		Year		
	0	1	2	3
Operating Costs				
Include Fuel Cost Effect (y / n)	y			
Misc Var O&M				
Change in Fuel Cost		\$2,240,182		
Variable O&M	\$0	\$2,240,182	\$2,298,427	\$2,298,427
Total Variable O&M		\$2,240,182	\$2,298,427	\$2,298,427
Fixed O&M	\$0	(\$64,000)	(\$65,664)	(\$67,371)
Total O&M	\$0	\$2,176,182	\$2,232,763	\$2,231,056
Total Capital Cost	\$1,495,000			
Financed with Common Equity	(\$897,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$598,000)			
Debt payments		(\$67,746)	(\$67,746)	(\$67,746)
Interest portion of payment		(\$44,850)	(\$43,133)	(\$41,287)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$149,500)	(\$269,100)	(\$209,300)
EOP Book Value	\$1,495,000	\$1,345,500	\$1,076,400	\$867,100
Property Taxes		(\$22,425)	(\$20,183)	(\$16,146)
Income tax adj for prop tax, depn, oper exp		(\$701,490)	(\$680,218)	(\$701,963)
Net Cash Flow (current \$, incl fin.)	(\$897,000)	\$1,384,521	\$1,464,617	\$1,445,201
Net Cash Flow (current \$, excl fin.)	(\$1,495,000)	\$1,452,267	\$1,532,362	\$1,512,946
Capital Expenditure Annuity @ WACC		(\$207,329)	(\$207,329)	(\$207,329)
Before Tax Cap Exp Ann		(\$219,502)	(\$219,502)	(\$219,502)
NCF with annualized capital		\$1,244,938	\$1,325,033	\$1,305,617
Current \$ /ton of NOx reduced		\$4,179.89	\$4,448.81	\$4,383.62
NCF w/ann cap. discount by infl rate		\$1,213,390	\$1,258,729	\$1,208,854
Sum of discounted NCF	\$15,568,125			
TOTAL Tons NOx reduced Proj. Life	4,468			
\$/ton NOx reduced (after taxes)	\$3,485			
Total Tons Clinker over project life	8,935,200			
\$/ton clinker	\$1.74			
Before Tax Net Cash Flow		\$1,934,255	\$1,993,078	\$1,995,408
Discounted Before Tax NCF		\$1,885,239	\$1,893,344	\$1,847,522
Sum of discounted Before Tax NCF	\$24,460,535			
TOTAL Tons NOx reduced Proj. Life	4,468			
\$/ton NOx reduced (before tax basis)	\$5,475			
\$/ton clinker	\$2.74			
Annual Capital Recovery	(\$164,450)			
Annual O&M	\$2,176,182			
Total Cost	\$2,011,732			
Annual NOx reduced (tons)	298			
\$/ton (per ACT document)	\$6,754		Consistent with method of ACT document	
\$/ton clinker	\$3.38			
	(\$6,115)		average	
	(\$3.06)			

NOx Reduction Case Spreadsheet	
KILN SNCR	
Kiln Technical Data	
Target Kiln Size (TPH clinker)	150
Initial NOx value (pph)	700
Initial NOx value (lb/ton clinker)	4.67
NOx reduction needed (up to 40%)	45%
Outlet NOx Value (pph)	385
Outlet NOx Value (lb/ton clinker)	2.57
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	45%
Primary Fuel Cost (\$/MMBTU)	\$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Urea (\$/gallon)	\$0.95
Cost of Urea (\$/ton)	\$406.74
Urea Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	\$25,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital Cost (\$)	\$900,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Before Tax WACC	12.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate (\$/\$1,000)	\$15.00
Pretax Rate of Return (ACT document)	10.0%

Process Analysis	KILN SNCR
Plant	
TPH clinker	150
lb/hr NOx reduced	315
lbmole/hr NOx reduced	7
Pri. Fuel Cost, \$/MMBTU	\$1.50
Urea Cost (\$/gallon)	\$0.95
Urea Cost (\$/ton)	\$406.74
Urea Cost (\$/lbmole)	\$12.20
Urea Utilization	50%
Urea usage (lbmole/hr)	6.8
Urea usage (gal/hr)	87.98
Urea Cost (\$/hr)	\$83.56
Heat Rate Increase	0.00%
Uncontrolled NOx	700.00
Controlled NOx	385.00
Capital Cost, includes license (\$/KW)	900,000
Fixed O&M (\$/yr.)	\$25,000
Capacity factor	0.45
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	621

KILN SNCR		Year		
	0	1	2	3
Operating Costs				
Urea Cost	\$0	(\$329,386)	(\$337,950)	(\$346,737)
Total Variable O&M		(\$329,386)	(\$337,950)	(\$346,737)
Fixed O&M	\$0	(\$25,000)	(\$25,650)	(\$26,317)
Total O&M	\$0	(\$354,386)	(\$363,600)	(\$373,054)
Total Capital Cost	\$900,000			
Financed with Common Equity	(\$540,000)			
Financed with Preferred Equity	\$0			
Preferred Dividends		\$0	\$0	\$0
Amount financed w/ debt	(\$360,000)			
Debt payments		(\$40,783)	(\$40,783)	(\$40,783)
Interest portion of payment		(\$27,000)	(\$25,966)	(\$24,855)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		(\$90,000)	(\$162,000)	(\$126,000)
EOP Book Value	\$900,000	\$810,000	\$648,000	\$522,000
Property Taxes		(\$13,500)	(\$12,150)	(\$9,720)
Income tax adj for oper exp, depn, prop tax		\$160,260	\$188,213	\$178,071
Net Cash Flow (current \$, incl fin.)	(\$540,000)	(\$248,409)	(\$228,321)	(\$245,486)
Net Cash Flow (current \$, excl fin.)	(\$900,000)	(\$207,626)	(\$187,538)	(\$204,703)
Capital Expenditure Annuity @ WACC		(\$124,813)	(\$124,813)	(\$124,813)
Before Tax Cap Exp Ann		(\$132,142)	(\$132,142)	(\$132,142)
NCF with annualized capital		(\$332,439)	(\$312,351)	(\$329,516)
Current \$ /ton of NOx reduced		(\$535.45)	(\$503.09)	(\$530.74)
NCF w/ann cap. discount by infl rate		(\$324,015)	(\$296,721)	(\$305,095)
Sum of discounted NCF	(\$4,661,382)			
TOTAL Tons NOx reduced Proj. Life	9,313			
\$/ton NOx reduced (after taxes)	(\$501)			
Total Tons Clinker over project life	8,869,500			
\$/ton clinker	(\$0.53)			
Before Tax Net Cash Flow		(\$500,028)	(\$507,892)	(\$514,915)
Discounted Before Tax NCF		(\$487,357)	(\$482,477)	(\$476,753)
Sum of discounted Before Tax NCF	(\$6,864,590)			
TOTAL Tons NOx reduced Proj. Life	9,313			
\$/ton NOx reduced (before tax basis)	(\$737)			
\$/ton clinker	(\$0.77)			
Annual Capital Recovery	(\$99,000)			
Annual O&M	(\$354,386)			
Total Cost	(\$453,386)			
Annual NOx reduced (tons)	621			
\$/ton (per ACT document)	(\$730.25)	Consistent with method of ACT document		
\$/ton clinker	(\$0.77)			
avg \$/ton NOx	(\$734)			
avg \$/ton clinker	(\$0.77)			

EXHIBIT 20

German Contribution to the Review of the Reference Document on Best Available Techniques in the Cement and Lime Manufacturing Industries

Part II: Cement Manufacturing Industries

Authors:
Richard Bolwerk, Gerald Ebertsch, Dr. Manfred Heinrich, Sebastian Plickert, Dr. Martin Oerter

Members of the National Expert Group

Annex I: Contribution to energy efficiency

Annex II: First waste heat power generation plant using the Organic Rankine Cycle process for utilizing residual clinker cooler exhaust air

Annex III: Example: Electrostatic Precipitator

Annex IV: Example: Bag Filter

Annex V: High efficiency SNCR

Annex VI: Selective Catalytic Reduction (SCR)

Annex VII: Example of co-incineration of alternative fuels

1 INTRODUCTION

In order to gather information for the German contribution to the review of the BREF „Cement and Lime Manufacturing Industries” a survey was initiated by the German national expert group. Members of the national experts group are representatives from public authorities and the cement manufacturing industries. In the survey data on 42 cement kilns was collected representing nearly all kinds of kilns currently operated in Germany. The clinker production of those plants was more than 92% of total national clinker production in the year 2004. Therefore the results of the survey are considered as being representative for the current situation in the German cement industry. The reported emissions are mainly cited from the ‘Umweltdaten der Deutschen Zementindustrie’ (environmental data) that are published yearly by the VDZ (German Cements Works Association). This information is based upon all kilns that were operated in 2004. Additionally data for the following contribution was gained from guideline No 2094 of the German Engineers Association VDI (VDI 2094: Emission Control of Cement Plants, March 2003). This guideline was handed over by the German delegation to the European IPPC-Bureau at the kick off meeting of the technical working group on the review of Cement and lime BREF (September 12-13, 2005). For more information beyond this contribution please see VDI 2094.

The total number of kilns in Germany with a valid permit is given in the following table:

	As at 01.01.2005		
	Number	Capacity t/d	%
Kilns with cyclone preheaters	45	114,750	88.3
Kilns with grate preheaters	16	14,070	10.8
Shaft kilns	8	1,200	0.9
Total	69	130,020	100
Average kiln capacity in t/d	Rotary kilns	2,112	
	Shaft kilns	150	

Table: Number and capacity of kilns with operating permits in the Federal Republic of Germany in the year 2004.
Source: Umweltdaten der deutschen Zementindustrie 2004

2 PRESENT CONSUMPTION/EMISSION LEVELS IN GERMANY / APPLIED TECHNIQUES

2.1 Use of energy

The theoretical fuel energy demand for cement clinker production is determined by the energy required for the chemical/mineralogical reactions (1700 to 1800 MJ/tonne clinker) and the thermal energy needed for raw material drying and pre-heating. The actual fuel energy use for different kiln systems is within the following ranges (MJ/tonne clinker):

3000-3800	for dry process, multi-stage (3 – 6 stages) cyclone preheater and precalcining kilns,
3100-4200	for dry process rotary kilns equipped with cyclone preheaters,
3300-4500	for semi-dry/semi-wet processes (Lepol-kiln),
up to 5000	for dry process long kilns,
5000-6000	for wet process long kilns and
3100-4200	for shaft kilns.

The electricity demand is about 90-150 kWh/tonne cement.

More information and modification proposals for the existing BREF see annex I.

For the first time in a German cement kiln the Organic Rankine Cycle Process for co-generating power from low-temperature waste heat has been applied. The initial results available indicate that 1.1 MW electrical power could be generated with the given mode of operation of the clinker cooler with a waste heat output of the clinker cooler exhaust air of 14 MW and and exhaust gas temperature of 300°C. More information see annex II.

The fuels used in German cement kilns and the energy substitution rate are shown in the following table.

Fuel	2004 [million GJ/a]
Coal	15.6
Lignite	31.7
Petcoke	3.8
Heavy fuel oil	2.6
Light fueloil	0.2
Natural gas and other gases	0.5
Other fossil fuels	0.7
Total fossil fuels	55.1
Total alternative fuels	40.2
Total thermal energy consumption	95.3

Table: Fuel energy consumption classified by energy sources

Electricity consumption was minimized in some cases by replacing old raw material mills via new mills. The following table gives an overview on the relationship between the energy consumption of the different grinding techniques. It has to be pointed out that it is not always possible to exchange one mill via another grinding device. Furthermore it is worth mentioning that an assessment of the most appropriate grinding technique should always consider also the economic aspects.

Grinding process	Energy consumption	Maintenance requirements	Drying capacity	Suitability for grinding to great fineness
Ball mill	100 %	minor	average	good
Gutbett roller mill	65 to 50 %	minor to major	low*	average
Vertical roller mill	75 to 70 %	average	high	average

*) Drying in classifier

Table: Comparison of grinding technologies based on key characteristics

Source: VDI 2094

1.2 Emissions to the air

The most relevant air emissions from cement kilns are the following:

- dust
- nitrogen oxides (NO_x)
- sulphur dioxide (SO₂)
- carbon oxides (CO, CO₂)
- hydrogen chloride
- hydrogen fluoride
- organic compounds (TOC)
- heavy metals
- polychlorinated dibenzodioxins and dibenzofurans (PCDD/F)

The following subsidiary processes of a cement plant can be sources for dust emissions:

- crushing of raw material
- raw material conveyors and elevators
- storage for raw materials and products
- grinding mills for raw material, cement and coal
- storage of fuels (pet coke, hard coal, lignite)
- dispatch of cement

Fugitive dust emissions may be released from open storage, road transport or conveyors of raw material and cement.

Typical emissions from German cement kilns are quoted in the following paragraphs. Flue gas abatement techniques are characterized, if applied.

2.2.1 Dust

German cement kilns are mostly equipped with electrostatic precipitators (ESP). In some cases also fabric filters are used. The current situation is shown in the following table. The data gathered by the questionnaire covers 42 German kilns (c.f. introduction).

Main filter systems		
■ system types and data of operation		status: July 2005
	41 electrostatic precipitators	8 fabric filters
year of construction	1962 to 2004	1999 to 2005
pressure loss in hPa	1 to 8	(2) 10 to 12
temperature in °C	90 to 190	90 to 160 ¹⁾
electric energy demand in kWh/t clinker	1 to 4	0.1 to 0.2
■ amount of filter dust and dust extraction		
	compound operation	direct operation
amount of filter dust in kg/t clinker	54 to 144 (1,718)	(10 to 70) 80 to 200
dust extraction in kg/t clinker	0 to 35	0 to 66 (165)

vdz.

1) 240 °C was reported by using glass fibres with PTFE membrane

The values in brackets refer to extreme values that have been reported in some individual cases. The values out side the brackets represent typical ranges. The overview also allows an estimation of filter dust and dust extraction where applicable.

Typical clean gas dust contents (daily mean values) attained by rotary kiln systems equipped with ESP range between < 10 – 30 mg/m³. An example for an electrostatic precipitator operated at a kiln with a clinker capacity of 3700 t/d is given in annex III. Measures for reducing safety caused shutdowns of ESP because of CO-trips see VDI 2094, chapter 2.2.1.2. Safety caused shutdowns of one ESP under optimized conditions see table below.

Year	Duration in total (min)	Number of yearly shut offs/ Maximum duration	Percentage on kiln operating time (%)
2000	12	7 shut offs / max. 3 min	0,003
2001	29	13 shut offs / max. 7 min	0,009
2002	1	1 shut offs / max.0,5 min	< 0,001
2003	6	3 shut offs / max. 4 min	0,001
2004	5	4 shut offs / max 2 min	0,001

After flue gas abatement with fabric filters dust emissions in the range from < 10 – 20 mg/m_n³ as daily mean value were reported. To meet these values layout design of fabric filters like air-to-cloth ratio range from < 0.5 – 2 m³/(m² min).

The German technical instruction on air quality control (TA Luft 2002¹) prescribe for the operation of cement kilns an emission limit value for dust of 20 mg/m³ (daily mean value, related to an oxygen content of 10 %). Existing installations have to comply with this emission limit value no later than 30th October 2007. If waste is used as fuel the emission limit value for dust range from 10 mg/m³ (100 % of rated thermal input comes from waste or more than 40 % of rated thermal capacity comes from hazardous waste) to 20 mg/m³ (daily average value, related to 10 % oxygen).

The continuously monitored dust emissions from German cement kilns related to the year 2004 can be seen in the following diagram (yearly mean values, 10 % oxygen, 273 K, 1013 hPa).

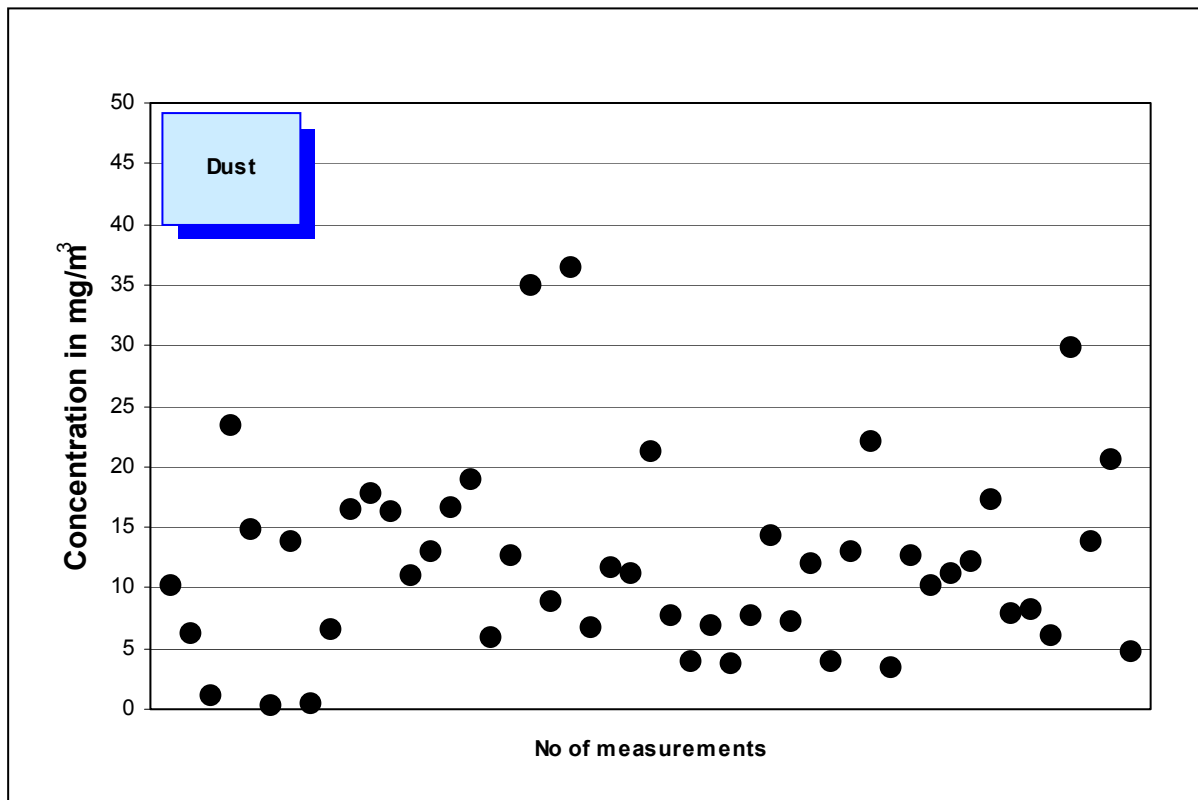


Fig.: Average dust concentrations in the clean gas of 49 rotary kilns (yearly mean values)

The separated dust from dust precipitators is used as product. The measured dust emission values did not depend on the type of fuels.

Connected and subsidiary processes

Nearly all connected and subsidiary processes of a cement plant can release dust emissions. In principle dust is separated via fabric filters e.g. in the following processes:

- crushing of raw material

¹ All emission limit values of the TA Luft 2002 given in the following paragraphs have to be complied with by 30th October 2007.

- storage for raw materials and cement
- grinding mills for raw material, cement and solid fuels
- dispatch of cement

In cases like crushing, grinding and dispatch equipment is kept under slight suction. The dust emissions from these sources are $< 20 \text{ mg/m}^3$. The sources are normally equipped with fabric filters. Conveyors and elevators are constructed as closed systems, if dust emissions are likely to be released from dusty material. Roads used by trucks are paved and cleaned periodically in order to avoid fugitive dust emissions. In addition spraying with water at the installation site is used to avoid fugitive dust emissions. Wherever possible, closed storage systems are used.

2.2.2 Oxides of nitrogen

The clinker burning process is a high-temperature process resulting in the formation of nitrogen oxides (NO_x). Nitrogen monoxide (NO) accounts for about 95% and nitrogen dioxide (NO_2) for about 5% of this compound present in the exhaust gas of rotary kiln plants. High process temperatures are required to convert the raw material mix to Portland cement clinker. Kiln charge temperatures in the sintering zone of rotary kilns range at around 1,450 C. To reach these, flame temperatures of about 2,000 °C are necessary.

For reasons of clinker quality the burning process takes place under oxidising conditions, under which the partial oxidation of the molecular nitrogen in the combustion air resulting in the formation of nitrogen monoxide dominates. This reaction is also called thermal NO formation. At the lower temperatures prevailing in a secondary firing unit, the nitrogen bound in the fuel can result in the formation of fuel-related NO . Nevertheless the total level of NO_x emissions is almost completely determined by the air borne nitrogen rather than by the fuel fired. Without reduction measures, process-related NO_x contents in the exhaust gas of rotary kiln plants would considerably exceed the specifications of the TA Luft 2002 (see below).

To reduce the NO_x -emissions in Germany process integrated measures and secondary NO_x -abatement technologies are applied. In 2004 8 kilns were operated with staged combustion technique, 32 kilns were operated with the SNCR-technique and one kiln with the SCR-technique. The yearly mean values of the NO_x emissions in 2004 are depicted in the following diagram.

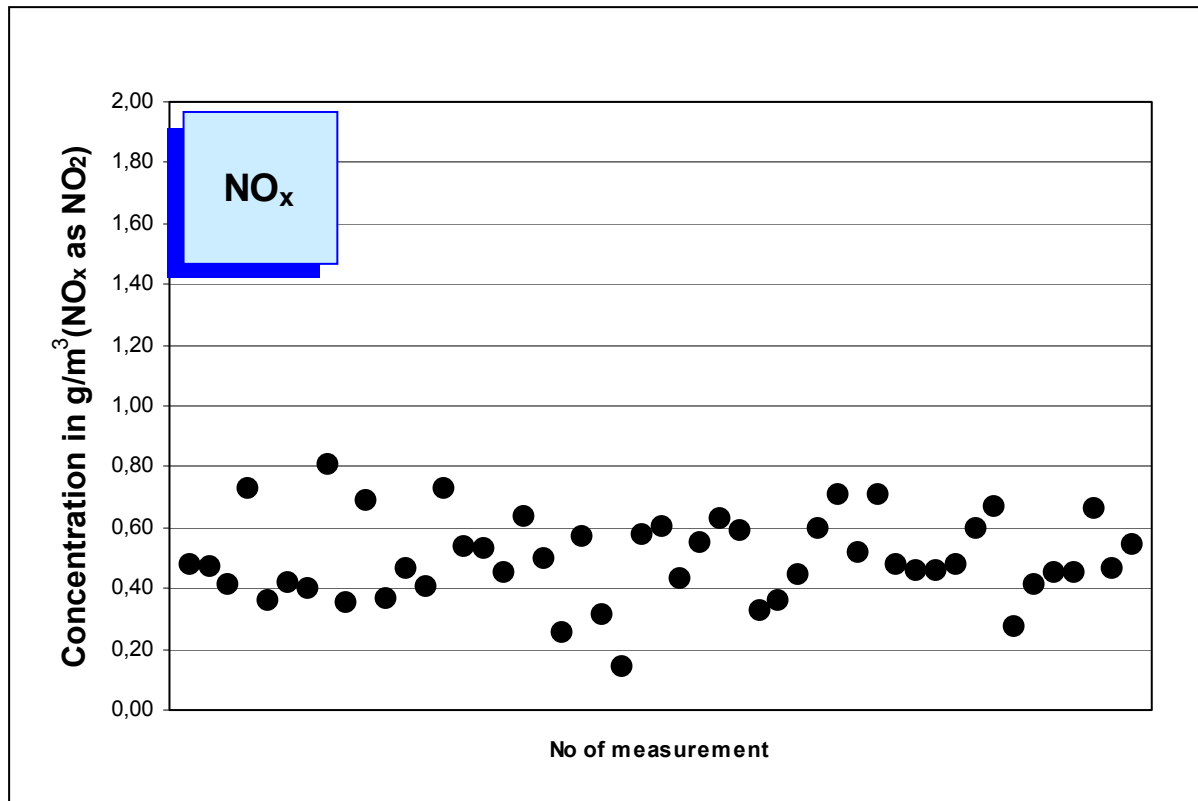


Fig. : Average yearly NO_x concentrations in the clean gas of 49 rotary kilns. Note: In 2004, the emissions of several kilns exceeded the emission values for cement plants specified by the TA Luft 2002 now. The operating permits for these works are based on higher NO_x limits. Some of these plants have been shut down or will be shut down within the next few years, respectively, while others will be retrofitted with NO_x reduction devices.

NO_x -Emission limit values in Germany

For the operation of cement kilns the TA Luft 2002 prescribes 0.50 g/m_n^3 as emission limit value for nitrogen dioxide and nitrogen monoxide, to be indicated as nitrogen dioxide. The emission limit value is defined as daily mean value, related to an oxygen content of 10 % in the waste gas. If waste is used as fuel more than 60% of rated thermal input the emission limit value for nitrogen oxides range from 200 mg/m_n^3 (100 % of rated thermal input comes from waste or more than 40 % of rated thermal capacity comes from hazardous waste) to 500 mg/m_n^3 (daily average value, related to 10 % oxygen). Existing installations have to comply with the German emission limit values 500 mg/m^3 or less than 500 mg/m^3 depending on the ratio of waste co-incineration no later than 30 October 2007.

Applied process integrated measures

The following techniques are applied, that have positive effect on the reduction of NO_x emissions arising during the manufacture of cement. Data on the emission reduction efficiency of process integrated measures at the moment are only partly available:

- Flame cooling by addition of water to the fuel or usage of liquid wastes with high water content

Addition of water to the fuel or directly to the flame or usage of liquid/solid wastes with high water content reduces the temperature and increases the concentration of hydroxyl radicals. This can have a positive effect on NO_x reduction in the burning zone and reduction rates of 10-

50% have been reported [CEMBUREAU report, 1997], [French report, 2003]. Additional heat is required to evaporate the water, which causes slight additional CO₂ emissions (approximately 0.1-1.5%) compared to the total CO₂ emission of the kiln. Water injection can cause kiln operation problems, such as reduced clinker output, and undesired clinker formation. For a kiln capacity of 3000 t cli./d the investment cost is estimated at 0.0-0.2 million € and the operating cost at 0.0-0.25 €/t clinker [CEMBUREAU report, 1997]. The NO_x-reduction efficiency reported ranges within 10 – 50 %

- Low-NO_x-burner

Designs of low-NO_x burners vary in detail but essentially the coal (fuel) and air are injected into the kiln through concentric tubes. The primary air proportion is reduced to some 6-10% of that required for stoichiometric combustion (typically 10-15% in traditional burners). Axial air is injected at high momentum in the outer channel. The coal may be blown through the centre pipe or the middle channel. A third channel is used for swirl air, its swirl being induced by vanes at, or behind, the outlet of the firing pipe.

The net effect of this burner design is to produce very early ignition, especially of the volatile compounds in the fuel, in an oxygen-deficient atmosphere, and this will tend to reduce the formation of NO_x. NO_x reductions of up to 30% are achievable in successful installations [British Cement Association, 1997], but the application of low-NO_x burners is not always followed by a reduction of the NO_x emissions. Low-NO_x burners can be applied to all rotary kilns, in the main firing as well as in the precalciner, and emission levels of 500-1000 mg/Nm³ have been reported [Dutch report, 1997]. The investment cost for a new low-NO_x burner is about 200000 to 350000 € for a kiln capacity of 3000 t cli./d [CEMBUREAU report, 1997]. If the existing firing system uses direct firing it must be changed to an indirect firing system to allow combustion with low primary air flow, this will mean an investment cost of about 600000 to 800000 € for a kiln capacity of 3000 t cli./d [CEMBUREAU report, 1997].

- Staged combustion

Staged combustion is applied at cement kilns supplied with several combustion stages. This technique is mostly carried out with specially designed precalciners. The first combustion stage takes place in the rotary kiln under optimum conditions for the clinker burning process. The second combustion stage is a burner at the kiln inlet, which produces a reducing atmosphere that decomposes a portion of the nitrogen oxides generated in the sintering zone. The high temperature in this zone is particularly favourable for the reaction that reconverts the NO_x to elementary nitrogen. In the third combustion stage the calcining fuel is fed into the calciner with an amount of tertiary air, producing a reducing atmosphere there, too. This system reduces the generation of NO_x from the fuel, and also decreases the NO_x coming out of the kiln. In the fourth and final combustion stage the remaining tertiary air is fed into the system as "top air" for residual combustion [Dutch report, 1997].

Calciners currently in use differ from one another essentially in the location of the fuel input, the way in which the fuel, kiln feed and tertiary air are distributed, and the geometric configuration [Dutch report, 1997].

Staged firing technology can in general only be used with kilns equipped with a precalciner. Substantial plant modifications would be necessary in cyclone preheater systems without precalciners. If this cannot be combined with an increase in production capacity the manufacturers offer a solution with so-called "small" tertiary air ducting and calciner. In this case only a small proportion of about 10-25% of the total heat needed from the kiln is passed through the calciner, but this is sufficient to produce a reducing zone for decomposing nitrogen oxides

[Billhardt, 1996]. On the other hand, experiences from a kiln with 10% firing in the kiln inlet shows that this is not sufficient to produce a sufficiently reducing zone. [Bodendiek, 2005]

NO_x emission concentrations below 500 mg/m³ can be achieved with highly reactive fuels, whereas with low reactive fuels 800 mg/m³ might be achieved. More extreme operating conditions, which allow lower NO_x emission levels, often lead to operational problems like increasing build-ups in kilns and calciners. An increase of the CO emissions is only the case in very few plants designed with relatively short residence times or where combustion is not properly optimised [Hoenig, 2003], [Bodendiek, 2006].

Possible reductions in NO_x by up to 50% have been claimed by the suppliers of the different staged firing systems. However, it is difficult to maintain the guaranteed values for this level of NO_x abatement while at the same time limiting the CO emissions [Billhardt, 1996]. Similar effects have been reported by Axelsen while using secondary fuels [Axelsen, 2003].

The investment cost for installing staged combustion at a precalciner kiln is 0.1-2 million €, the cost depending on the design of the existing calciner. The investment cost for a precalciner and the tertiary duct for a 3000 t/d preheater kiln with a grate cooler into a precalciner kiln is about 1 to 4 million €. The investment cost for the transformation of a 3000 t/d preheater kiln with a satellite cooler into a precalciner kiln with a grate cooler is about 15 to 20 million € [CEMBUREAU report, 1997].

Lump alternative fuel (for example tyres) firing is a possible variant of the staged combustion technique as a reducing zone is created when the lump fuel is burned. In preheater/precalciner kilns the lump fuel can be introduced at the kiln inlet or at the precalciner. Lump fuel firing is reported to have a positive effect on NO_x reduction (up to 20-30% reduction). However, it is very difficult to produce a controlled reducing atmosphere with lump fuel firing [CEMBUREAU report, 1997].

- Process optimisation, like smoothing and optimising plant operation, homogenisation of fuel feedings

Many cement plants have taken general primary optimisation measures, such as process control measures, improved firing technique, optimised cooler connections and fuel selection, and these also reduce NO_x emissions. NO_x -emissions in this case range within 500 and 1000 mg/m³. In the recent years great progress was observed in reduction NO_x-emissions by process integrated measures.

Some modern well-optimised preheater kiln systems and preheater/precalciner kiln systems utilising high volatile fuel may achieve an emission level less than 500 mg NO_x/m³ with process-integrated measures. Raw materials quality (the firing properties of the raw mix), availability of high volatile fuels and kiln system design are among the reasons for not being able to achieve this level.

Secondary measures

-SNCR-Technique

Selective non-catalytic reduction (SNCR) involves injecting ammonia or ammonia precursory compounds into the combustion gas to reduce NO to N₂. The reaction has an optimum effect in a temperature window of about 830 to 1050 °C, and sufficient retention time must be provided for the injected agents to react with NO. The right temperature window is easy to obtain in suspension preheater kilns, precalciner kilns and in Lepol kilns. In long wet and dry process kilns it is very difficult to obtain the right temperature and retention time needed. Only one plant

with a long dry kiln has so far successfully applied SNCR reduction and reaches efficiencies between 40 and 50% [Görtzen, 2003].

It is important to maintain the temperature range mentioned above. If the temperature falls below this level unconverted ammonia is emitted (so-called NH_3 slip) and at significant higher temperatures the ammonia is oxidised to NO_x . NH_3 slip may also occur at elevated NH_3/NO molar ratios, i.e. from a molar ratio of about 1.0-1.2. NH_3 slippage has in other sectors of industry sometimes resulted in the formation of aerosols of ammonium chlorides and ammonium sulphates which have passed through the filter and become visible as a white plume above the exhaust gas stack. Unreacted ammonia may be oxidised and transformed into NO_x in the atmosphere and NH_3 slippage may also result in ammonia enriched dust which may not be recycled to the cement mill [Junker, 2001]. N_2O emissions play only a minor role, as spot tests revealed concentrations between 1 and 5 mg/m^3 which is approximately the detection limit [VDZ, 1999]. N_2O emissions are more likely when urea is used as reducing agent.

The most common reducing agent is ammonia solution of about 25% NH_3 . The transport and storage of ammonia requires additional safety measures [CEMBUREAU report, 1997]. Waste solutions from other production processes can be utilised as ammonia carriers as well. Other possible reducing agents which can be employed on an industrial scale are ammonium salt solutions, dried urea (urea prills), urea solutions, nitrolime or cyanamide and similar other substances [British Cement Association, 1996], [Görtzen, 2003]. However not all these agents have achieved general acceptance to date. The storage and transport facilities have to be designed according to the physical and chemical properties of the respective agent.

Most SNCR installations operating in Germany are designed and/or operated for NO_x reduction rates of 10 - 50% and emission levels of < 500 - 800 $\text{mg NO}_x/\text{m}^3$. In combination with process integrated measures emission limit values below 500 mg/m^3 as daily mean value are achieved. In this context it is noteworthy that those low values can only be achieved if the initial NO_x level is already low as well.

- High efficiency SNCR-technique

The high efficiency SNCR-Technique is a further development of the SNCR-technique. In one German cement plant the high efficiency SNCR-technique is in operation. There under controlled conditions over 8 lances ammonia water (25 % ammonia solution) is injected into the preheater. The arrangement of the lances is determined by the temperature profile in the riser duct. The injection of ammonia water is process controlled by the measured temperature profile in the preheater nearby the lances. Therefore the NH_3 slip and the consumption of ammonia water can be reduced. At the moment trials with governmental financial support of the federal state of Bavaria are carried out to achieve a target value for NO_x of 200 mg/m^3 . Within the first trials it was possible to achieve 200 mg/m^3 for some days in case of low initial NO_x -levels in the untreated waste gas. During interconnected operation with raw mill on the NH_3 slip was low. In direct operation (mill off) the NH_3 slip in individual cases was very high. Negative effects on the cement quality because of ammonia however were not detected. More trials under optimized conditions (reducing NH_3 slip) are carried out at the moment. More results will be available by the end of 2006. For more information see annex V.

- SCR-Technique

The SCR-Technique reduces NO and NO_2 to N_2 with the help of NH_3 and a catalyst at a temperature range of about 300 – 400 °C. In one German cement plant this technique is used as high dust treatment technology. The NO_x emission limit for this plant is 500 mg/m^3 as daily mean value. In 2005 90 % of all daily measured NO_x mean values were below this emission limit. The NH_3 -Slip was not relevant. In order to ensure full-time emission limit compliance, the

Solnhofen plant was equipped with an SNCR system for backup operation in 2006. At the moment only the SNCR- technique is operated at the kiln for comparison of operational costs with the installed SCR-technique. For more information see annex VI.

2.2.3 Sulphur dioxide

Sulphur is input into the clinker burning process via raw materials and fuels. Depending on their respective deposits, the raw materials may contain sulphur bound as sulphide or sulphate. Higher SO₂ emissions by rotary kiln systems of the cement industry might be attributable to the sulphides contained in the raw material, which become oxidised to form SO₂ at the temperatures between 370 °C and 420 °C prevailing during the kiln feed preheating process. Most of the sulphides are pyrite or marcasite contained in the raw materials. Given the sulphide concentrations found in German raw material deposits, SO₂ emission concentrations can total up to 1.2 g/m³ depending on the site location. The cement industry has made great efforts to reduce SO₂ emissions. For example, lime hydrate is utilised at eleven kiln systems to lower SO₂ emissions.

The sulphur input with the fuels is completely converted to SO₂ during combustion in the rotary kiln. In the area of the preheater and the kiln, this SO₂ reacts to form alkali sulphates, which are bound in the clinker.

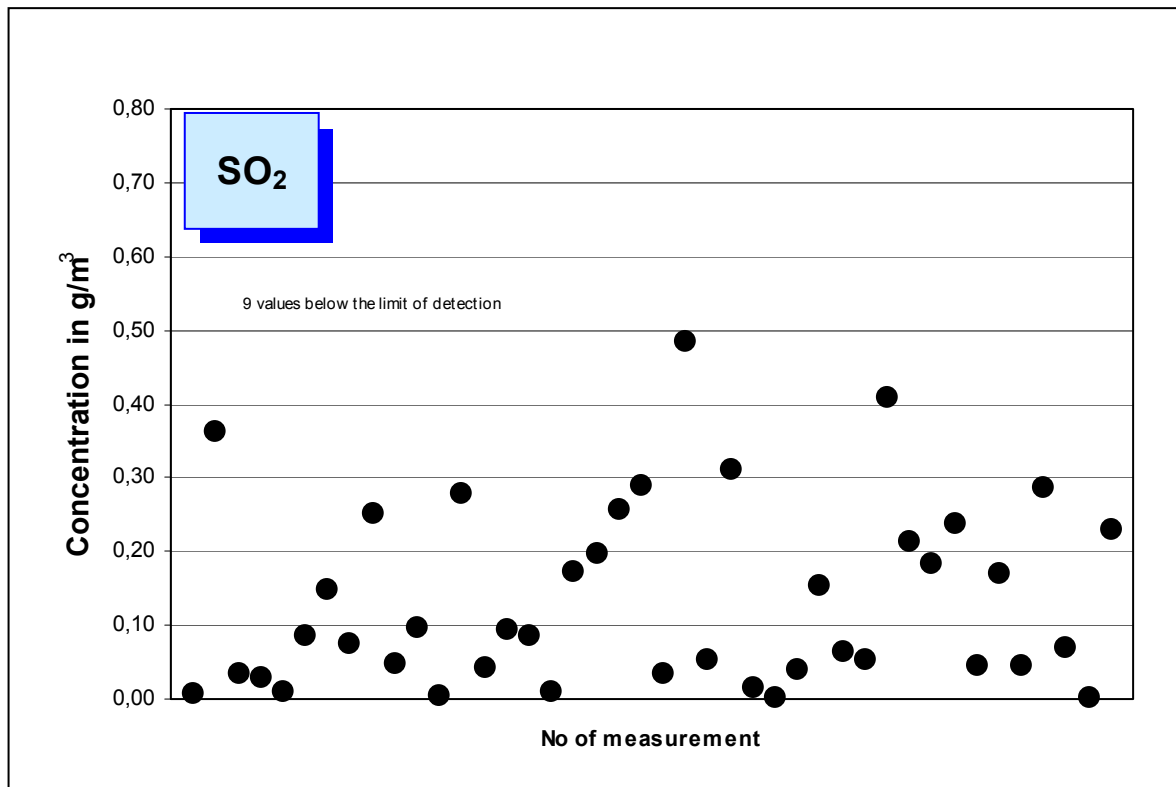


Fig.: Average SO₂ concentrations in the clean gas of 49 rotary kilns.

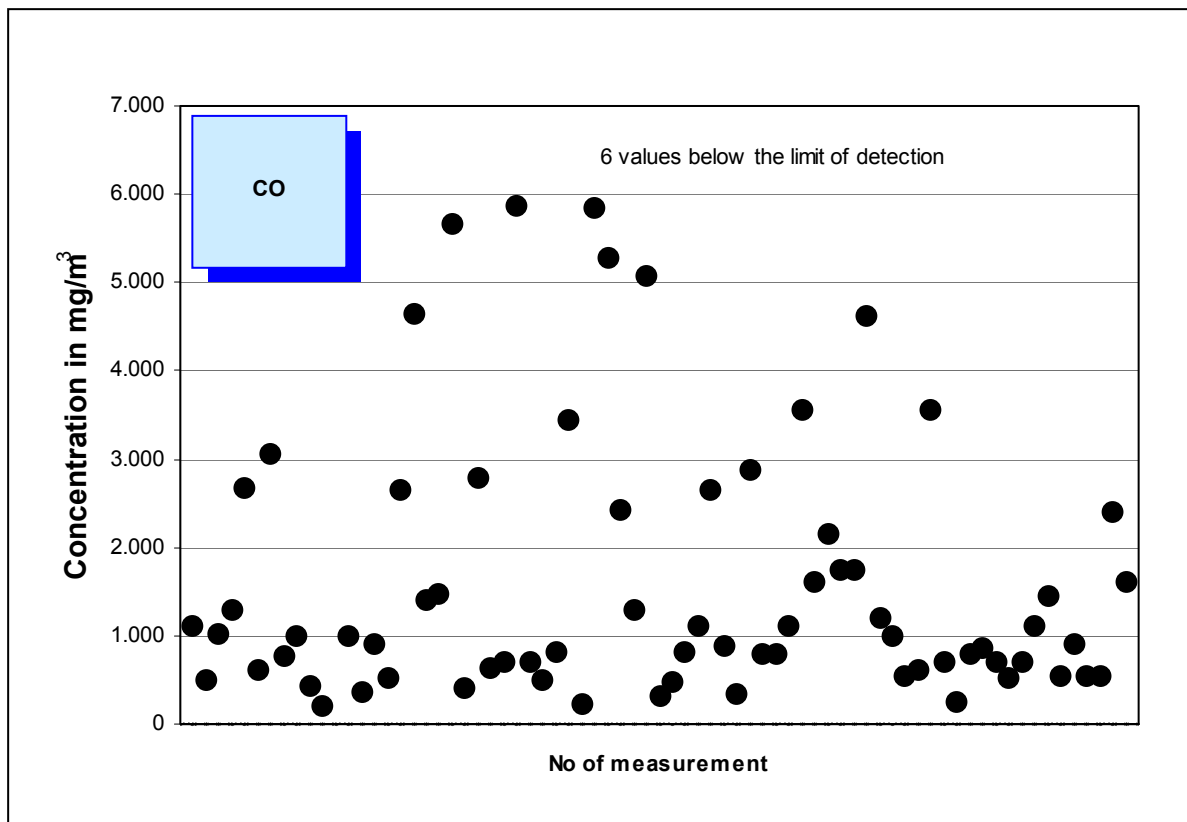
SO₂ -Emission limit values in Germany

The German TA Luft 2002 provides in general 0.35 g/m_n³ as emission limit value for sulphur dioxide. The emission limit value has to be considered as daily mean value, related to an oxygen content of 10 % for lime kilns.

2.2.4 Carbon monoxide (CO) and total carbon (ΣC)

The emissions of CO and organically bound carbon during the clinker burning process are caused normally by the small quantities of organic constituents input via the natural raw materials (remnants of organisms and plants incorporated in the rock in the course of geological history). These are converted during kiln feed preheating and become oxidised to form CO and CO₂. In this process, small portions of organic trace gases (total organic carbon) are formed as well. In case of the clinker burning process, the content of CO and organic trace gases in the clean gas therefore does not permit any conclusions on combustion conditions. However improper burning conditions in the secondary firing can lead to additional CO-emissions. On the other hand it has to be pointed out that such an increase in the CO emission rate coincides with a decrease in the NO_x emissions.

In energy conversion plants, such as power stations the exhaust gas concentrations of CO and organically bound carbon are a yardstick for the burn-out rate of the fuels. By contrast, the clinker burning process is a material conversion process that must always be operated with excess air for reasons of clinker quality. Together with long residence times in the high-temperature range, this leads to complete fuel burn-up.



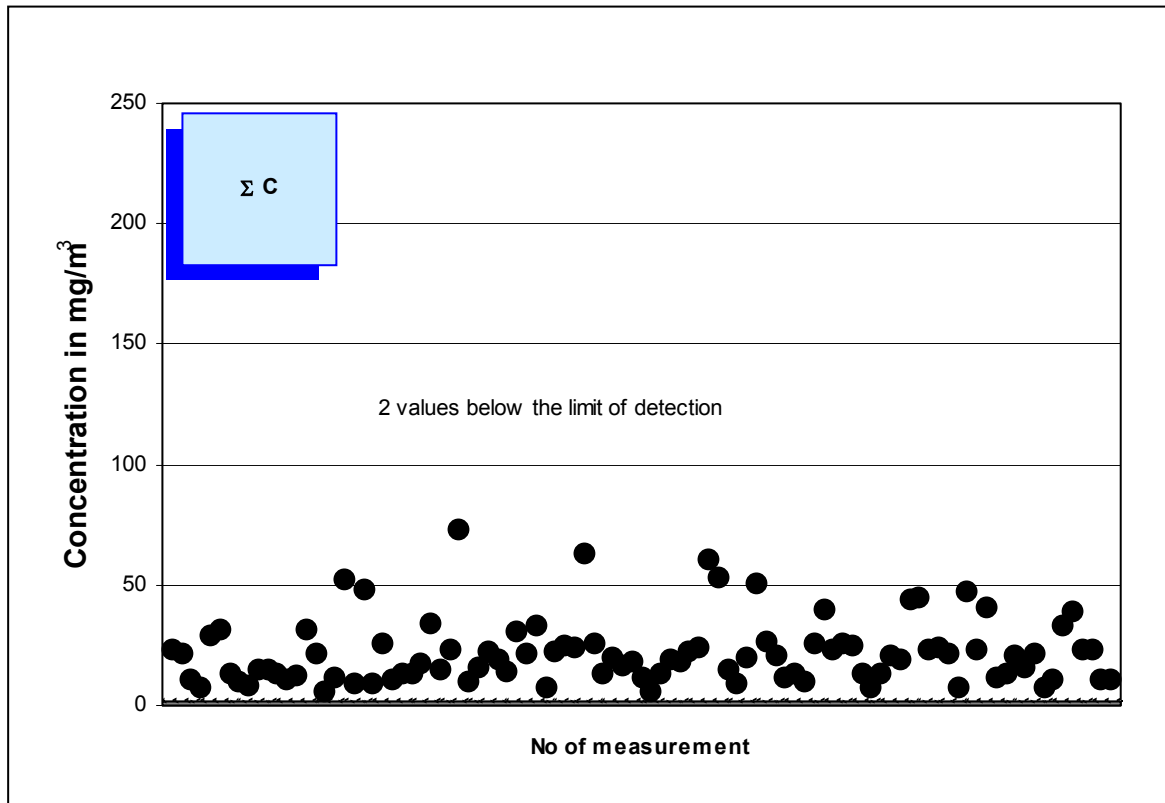
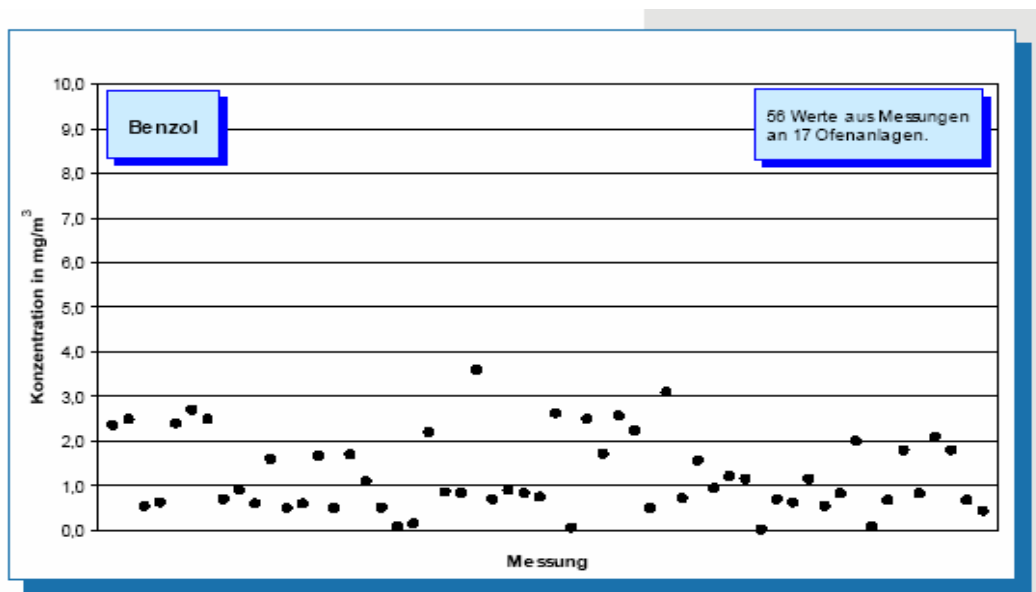


Fig. : Total organic carbon concentration values measured in the clean gas of 27 rotary kilns.

In some German plants additional measurements of benzene have been carried out in 2004. Benzene emissions in low concentrations are caused by the small quantities of organic constituents input via the natural raw materials (remnants of organisms and plants incorporated in the rock in the course of geological history) during kiln feed preheating. The emissions level in German kilns shows the following figure. The benzene emissions were not dependent on the fuels used.



2.2.5 Dioxins and furans (PCDD/F)

Rotary kilns of the cement industry and classic incineration plants mainly differ in terms of the combustion conditions prevailing during clinker burning. Kiln feed and rotary kiln exhaust gases are conveyed in counter-flow and mixed thoroughly. Thus, temperature distribution and residence time in rotary kilns afford particularly favourable conditions for organic compounds, introduced either via fuels or derived from them, to be completely destroyed. For that reason, only very low concentrations of polychlorinated dibenzo-p-dioxins and dibenzofurans (in short: dioxins and furans) can be found in the exhaust gas from cement rotary kilns. Investigations have shown that their emissions are independent on the type of fuels used.

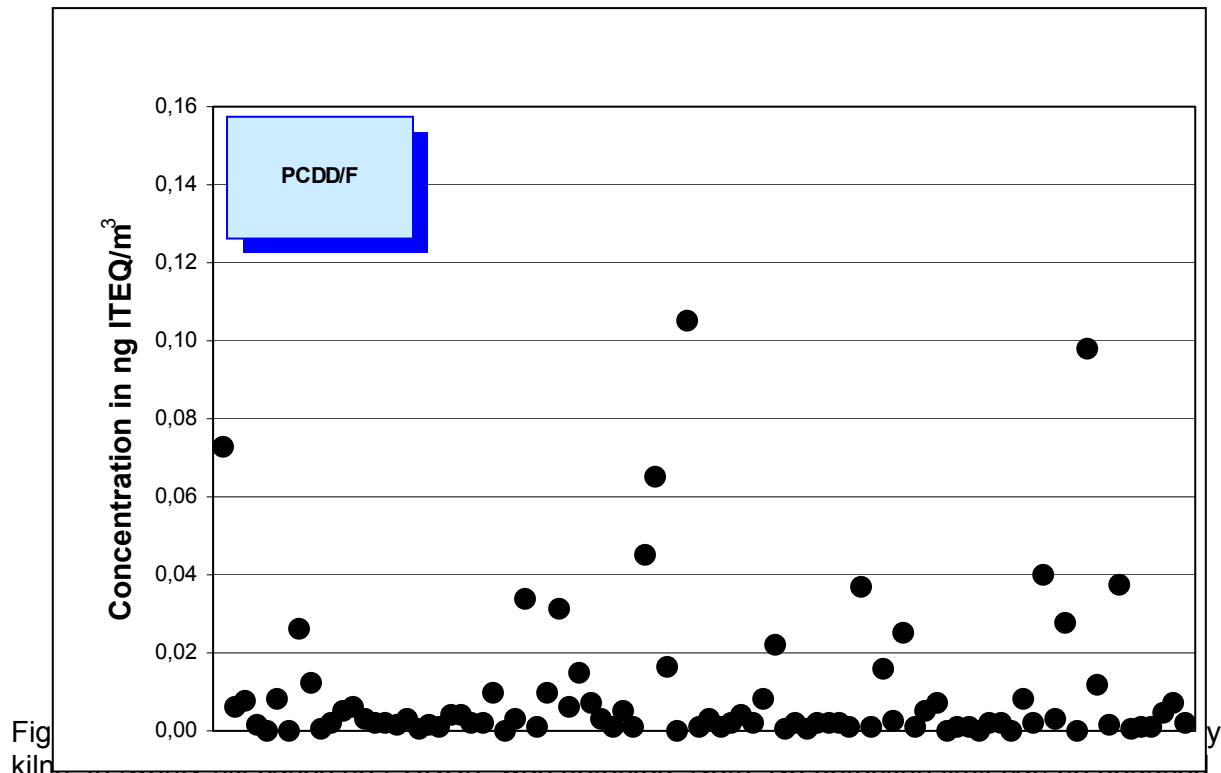
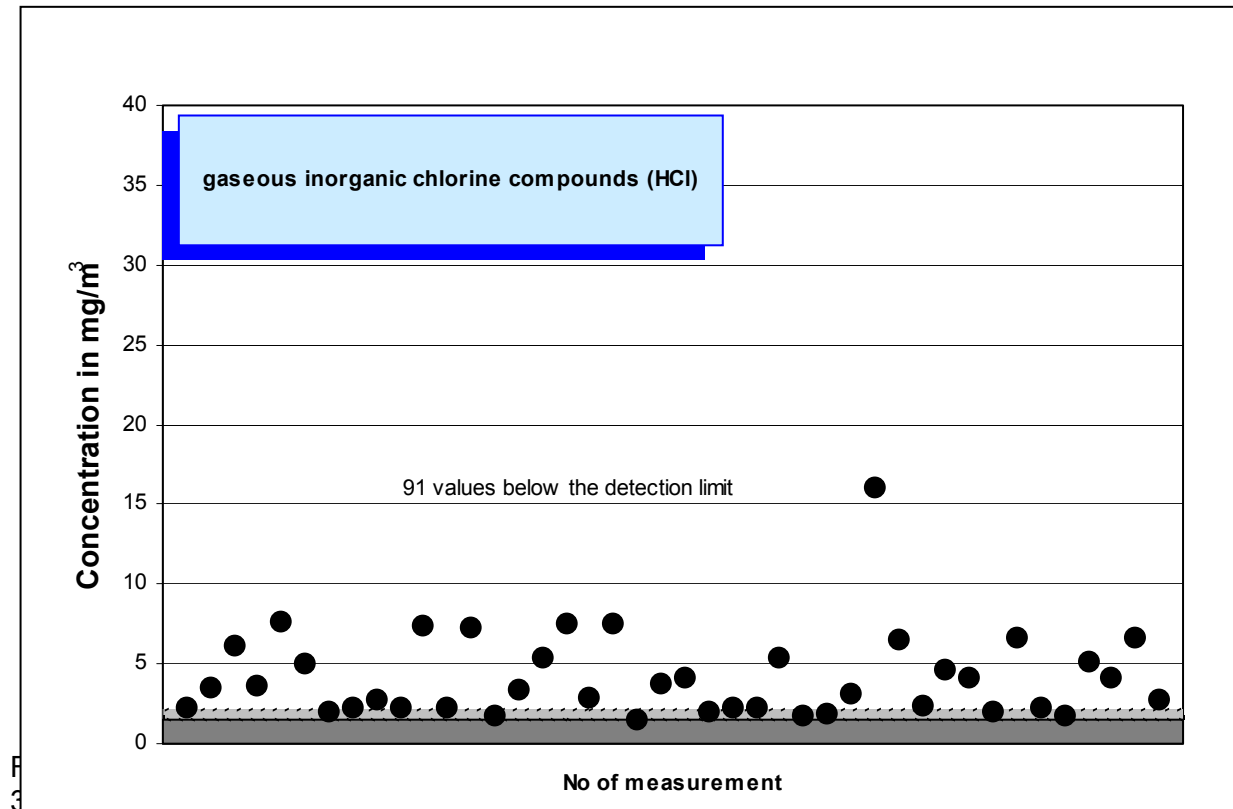


Fig. 1. PCDD/F concentrations in the exhaust gas of rotary kilns. In only six cases no PCDD/F was detected. Note: the detection limit can be decided from the standard. To evaluate the measurement results, inter-laboratory variation of the method (comparison between different laboratories) can be referred to. Pursuant to DIN EN 1948 it amounts to ± 0.05 ng ITEQ/m³. (ITEQ: international toxicity equivalent)

2.2.6 Gaseous inorganic chlorine compounds

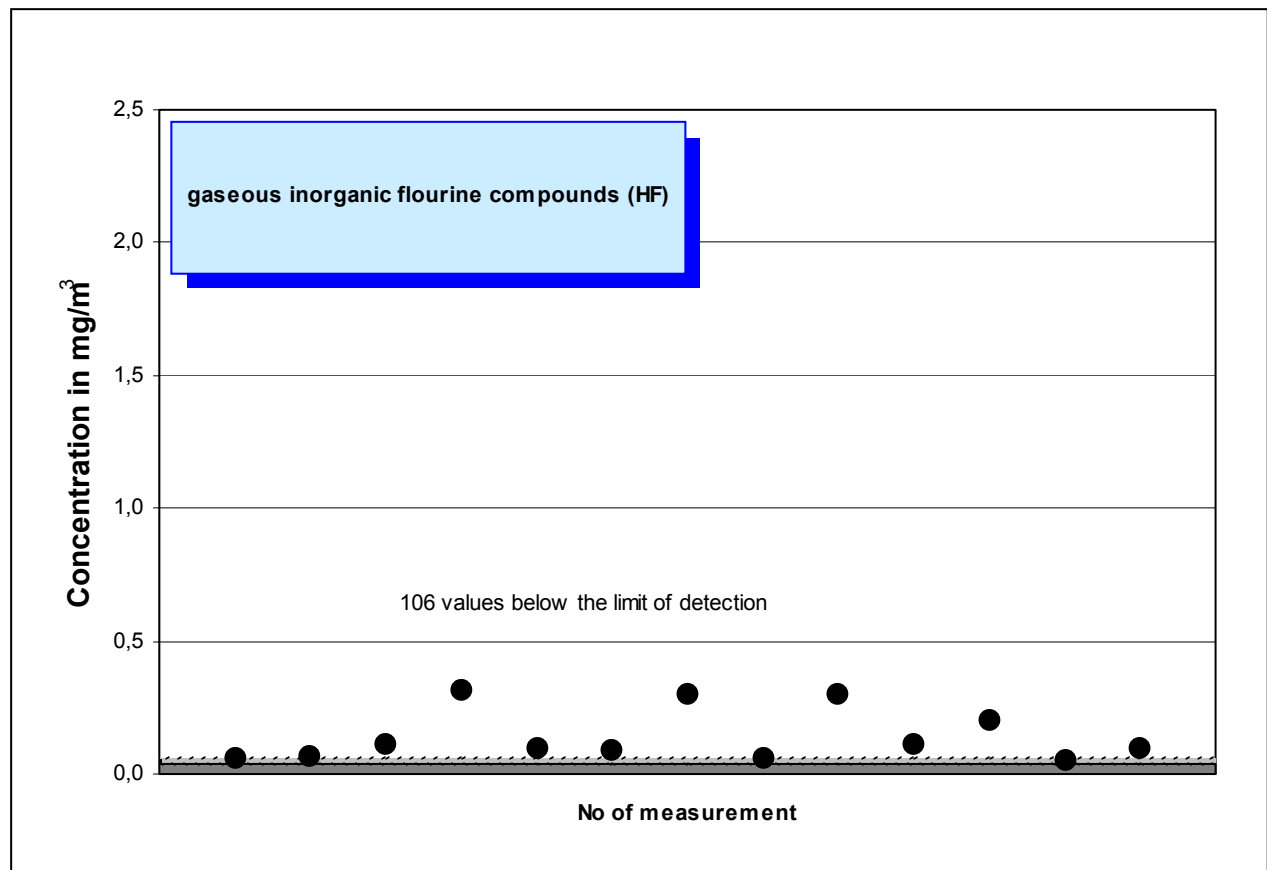
Chlorides are minor additional constituents contained in the raw materials and fuels of the clinker burning process. They are released when the fuels are burnt or the kiln feed is heated, and primarily react with the alkalis from the kiln feed to form alkali chlorides. These compounds, which are initially vaporous, condense on the kiln feed or the kiln dust, respectively, at temperatures between 700 °C and 900 °C, subsequently re-enter the rotary kiln system and evaporate again. This cycle in the area between the rotary kiln and the preheater can result in coating formation. A bypass at the kiln inlet allows to effectively reduce alkali chloride cycles and to thus diminish operational malfunctions.

During the clinker burning process, gaseous inorganic chlorine compounds are either not emitted at all or in very small quantities only. Owing to the alkaline kiln gas atmosphere, the formation of hydrogen chloride (HCl) in the exhaust gas can be virtually ruled out. Gaseous inorganic chlorides detected in the exhaust gas of rotary kiln systems are generally attributable to ultra-fine grain size fractions of alkali chlorides in the clean gas dust. They can pass through measuring gas filters, thus feigning the presence of the gaseous compounds.



2.2.7 Gaseous inorganic fluorine compounds (HF)

Of the fluorine present in rotary kilns, 90 to 95 % is bound in the clinker, and the remainder is bound with dust in the form of calcium fluoride stable under the conditions of the burning process. Owing to the great calcium excess, the emission of gaseous fluorine compounds and of hydrogen fluoride in particular, is virtually excluded. Ultra-fine dust fractions that pass through the measuring gas filter may simulate low contents of gaseous fluorine compounds in rotary kiln systems of the cement industry.



38 rotary kilns (given as HF).

2.2.8 Heavy metals

The emission behaviour of the individual elements in the clinker burning process is determined by the input scenario, the behaviour in the plant and the precipitation efficiency of the dust collection device. The trace elements introduced into the burning process via the raw materials and fuels may evaporate completely or partially in the hot zones of the preheater and/or rotary kiln depending on their volatility, react with the constituents present in the gas phase, and condense on the kiln feed in the cooler sections of the kiln system. Depending on the volatility and the operating conditions, this may result in the formation of cycles that are either restricted to the kiln and the preheater or include the combined drying and grinding plant as well.

Trace elements from the fuels initially enter the combustion gases, but are emitted to an extremely small extent only owing to the retention capacity of the kiln and the preheater.

Under the conditions prevailing in the clinker burning process, non-volatile elements (e.g. arsenic, vanadium, nickel) are completely bound in the clinker. Elements such as lead and cadmium preferably react with the excess chlorides and sulphates in the section between the rotary kiln and the preheater, forming low-volatile compounds. Owing to the large surface area available, these compounds condense on the kiln feed particles at temperatures between 700 °C and 900 °C. In this way, the low-volatile elements accumulated in the kiln-preheater-system are precipitated again in the cyclone preheater, remaining almost completely in the clinker.

Thallium and its compounds condense in the upper zone of the cyclone preheater at temperatures between 450 °C and 500 °C. As a consequence, a cycle can be formed between preheater, raw material drying and exhaust gas purification.

Mercury and its compounds are not completely precipitated in the kiln and the preheater. They condense on the exhaust gas route due to the cooling of the gas and are partially adsorbed by the raw material particles. This portion is precipitated in the kiln exhaust gas filter. To prevent a long-cycle increase in mercury emissions, it may become necessary to limit the concentration of the external cycle, e.g. by continuously or intermittently bleeding part of the dust collected in the electrostatic precipitator from the system. The dust bleed stream is re-circulated to the cement mill as raw material. In case of the energy recovery of alternative fuels (waste fuels) in Germany the mercury input to the kiln is limited regularly (ranges normally within 0.5 to 1 mg/kg). Another possibility is to reduce waste gas temperature after evaporation cooler to improve the precipitation of mercury and its compounds during dust filtration.

In principle it has to be pointed out that heavy metal emissions from the clinker production process are influenced by the behaviour of the individual heavy metals in the rotary kiln system, the input situation as well as the collection efficiency of the dust collector. The input situation is determined by the trace element concentrations in the raw materials and fuels processed. As the raw material/fuel mass ratio for clinker production is approx. 10 to 1, this means that the raw material-related inputs are decisive for the emissions.

Further details concerning the behaviour of trace elements in the clinker burning process are given in the guideline VDI 2094 "Emission control cement plants".

The yearly published environmental data of the German cement industry (VDZ) show that trace element emission concentrations are on a low overall level and are not dependent on the waste incineration. For example, the average values measured in 2004 of the trace elements listed in the German ordinance on waste incineration (17th BImSchV) were below the detection limit in merely about 20% of all cases.

The following diagram depicts the situation for the volatile trace element mercury. A complete overview of the emissions of all German kilns operated in 2004 can be found in Umweltdaten der Deutschen Zementindustrie 2004 (www.vdz-online.de).

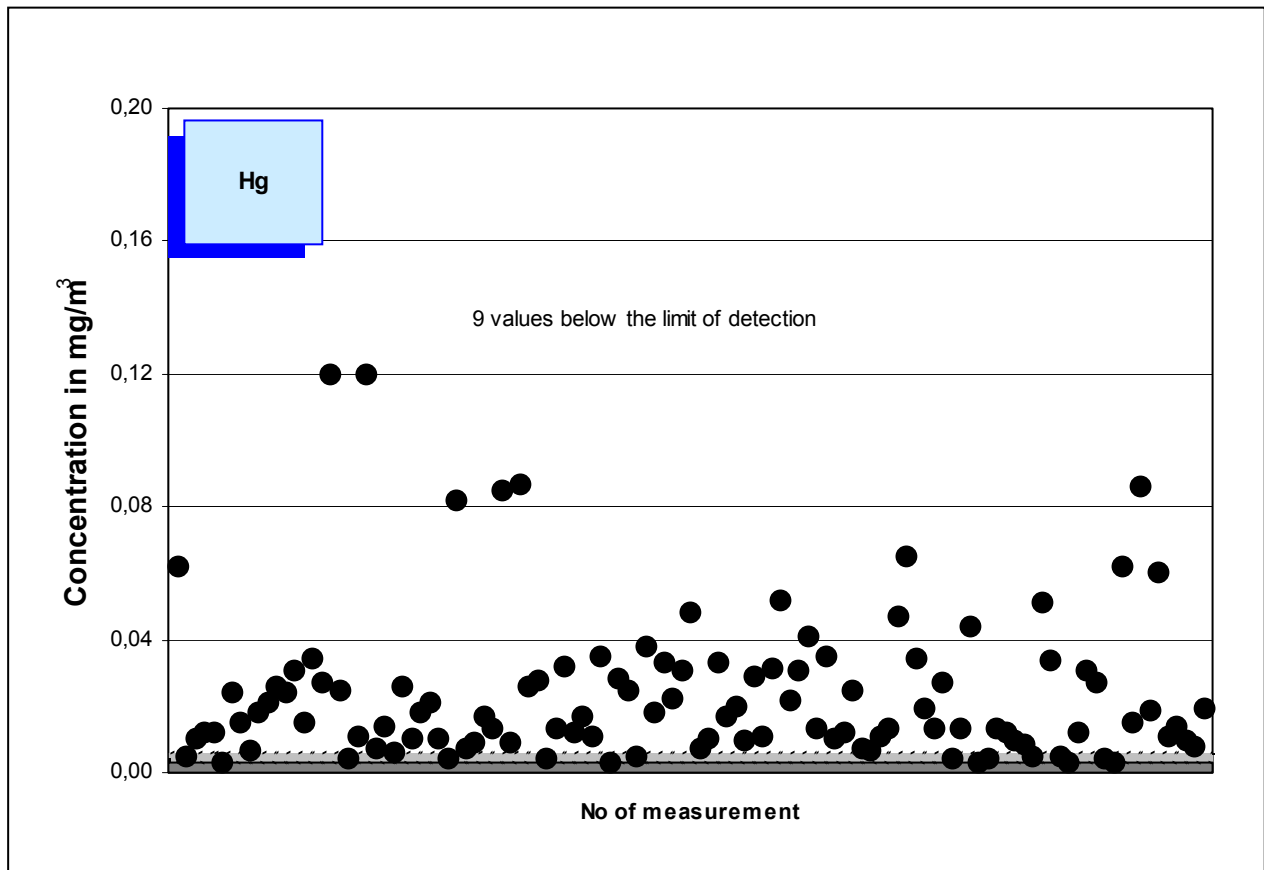


Fig.: Mercury concentration values measured in the clean gas of 40 rotary kilns.

2.2.9 Monitoring of emissions

Continuous measurements

In the waste gas of German cement kilns regularly dust, NO_x, SO₂ and mostly CO emissions are monitored continuously. In the case of co-incineration of waste often TOC- and Hg-emissions (especially in the case of co-incineration of sewage sludge) additionally are monitored continuously.

Periodic measurements

Periodic measurements are carried out for the following pollutants, unless monitored continuously:

- CO
- SO₂
- TOC

Depending on input fuels – especially in the case of waste co-incineration –, process conditions and the relevance of the emissions, additional measurements are carried out for the following pollutants:

- HCl
- HF
- heavy metals
- benzo-a-pyrene
- benzene
- PCDD/F

Recurrent measurements are usually required at three-year intervals in the case of plants using fossil fuels. In case of co-incineration of waste or alternative fuels recurrent measurements have to be carried out once a year.

3 USE OF WASTE/ WASTE FUELS

In principle, the clinker burning process lends itself well to environmentally beneficial waste-to-energy and material recycling applications. The decisive process characteristics for waste processing can be summarized as follows:

- Maximum gas temperatures of 2000 °C in the rotary kiln (main firing system)
- Gas retention times of about 8 s at temperatures above 1200 °C in the rotary kiln
- Solids temperature in the rotary kiln of about 1450 °C
- Oxidizing gas atmosphere in the rotary kiln
- Gas retention times in the secondary firing system of more than 2 s at temperatures above 850 °C; in calciners, the retention times are correspondingly longer
- Solids temperatures in the secondary firing system and/or the calciner of 850 °C
- Uniform burnout conditions regardless of load variations due to the high thermal capacity of the rotary kiln
- Destruction of organic pollutants due to the high temperatures at sufficiently long retention times
- Sorption of gaseous components like HF, HCl, SO₂ on alkaline reactants
- High retention capacity for particle-borne heavy metals
- Short retention of exhaust gases in the temperature range conducive to de-novo-synthesis of PCDD/F
- Complete utilization of fuel ashes as clinker components and hence, simultaneous material recycling and energy recovery, regardless of the heating value
- No generation of production-specific wastes due to complete material utilization
- Chemical-mineralogical incorporation of trace elements into the clinker matrix

3.1 Use of waste as secondary fuels

The German cement industry uses primarily hard coal and brown coal as conventional fuels. As the clinker burning process offers favourable conditions for waste co-processing, wastes are substituted for part of these conventional fuels. High calorific waste can substitute primary fuel in cement kilns. Therefore a constant waste quality is essential (e.g. sufficient calorific value, low heavy metal content (especially mercury and thallium), the waste has to be suitable for the burners). Furthermore the waste fuel has to be available in sufficient quantity. Normally different types of combustible wastes or wastes with separable high calorific fractions are prepared in special waste management facilities. The technologies used to prepare and blend certain waste fuel qualities depend on the characteristics of the input material and the requirements of the users. Even mono waste materials like production-specific wastes are treated and blended prior to use in waste facilities to ensure a homogeneous mixture with nearly constant thermal properties and chemical composition. Only in some cases, wastes can be just used as they are delivered without further processing, for example used tyres or used oil.

Depending on their composition, wastes in cement kilns are incinerated either in the main firing system or in the secondary firing system. In 2004, some 42 % of the fuel energy demand was provided by waste, corresponding to coal savings of more than 1,000,000 t. Main alternative fuels fired were pretreated industrial waste fractions (approx. 860,000 t) and scrap tyres (approx. 250,000 t). Other waste streams used as fuel substitutes include defined fractions from industrial waste, wood, sewage sludge and other suitable materials.

The table below shows the use of alternative fuels in the German cement industry in 2004. In total 2,042,000 t of waste fuels were utilized in 2004 in Germany.

Alternative fuel	Quantity in 2004 [1000 t/a]
tyres / rubber	290
waste oil	100
processed fractions of industrial / commercial waste	863
processed fractions of domestic waste	157
animal meal and fat	439
scrap wood	42
solvents	72
podsol	11
sewage sludge	48
other	20
total	2042

The following summary shows waste groups that have in principle turned out to be suitable for the energy and material recovery in the clinker burning process.

- wood
- paper
- waste oil
- podsol
- electrode coke
- pellets from oil gasification
- soot
- graphite waste
- plastics
- solvents
- tyres / rubber
- textile waste
- sewage sludge with suitable Hg-content (see chapter 2.2.9)
- other residues (not subject to special surveillance)
- suitable fractions of municipal waste or commercial waste similar to municipal waste

The requirements for the origin and quality of the mono waste fractions have been defined by restricting the eligible waste streams to individual waste codes. In this connection, the specific conditions of the cement production process and the resultant opportunities and limitations of waste utilization have been taken into account.

The ban on landfilling of unprocessed municipal waste in Germany has led to an increasing number of mechanical-biological treatments plants in operation. As a consequence the utilization of pre-treated mixed municipal waste fractions is an issue of growing concern. After suitable pre-processing, individual municipal or commercial waste fractions can meet the requirements for environmentally compatible reuse in cement plants.

Use of Solid Waste

The important characteristics for waste fuel are the calorific value, water content, sulphur, chlorine and heavy metal content. Source selection may be the first action to take into account for monostreams to reduce of materials, that might cause operation or quality problems in the cement process like heavy metals or PVC (mainly responsible for the chlorine content). In mixed wastes heavy metals can be separated in a screening step. The main part of the heavy metals is found in the fine fraction. Furthermore non ferrous elements can be selected by eddy current separators. PVC appears in a wide range of particle sizes, so screening processes are not suitable to discharge PVC. It can be separated by automatic sorting, e.g. auto recognition of plastics by infrared spectroscopy.

Not every combustible solid waste is suitable as fuel in the clinker burning process. Solid waste can be an inhomogeneous mixture of very diverse components: combustible fractions (e.g. paper-, cardboard, plastics, rubber, and wood residues) and varying amounts of inert materials (e.g. sand, stone, ceramics, ferrous / non-ferrous metals and organic wet materials). Waste like mixed municipal waste, mixed commercial waste or mixed construction and demolition waste has to be pre-treated in waste management facilities to separate the high calorific fraction. The extent of the waste treatment operation, such as sorting, crushing, pelletising, depends on the waste fuel application. More information see BREF "Best Available Techniques for the Waste Treatments Industries", chapter 4.5 "Techniques to consider for the preparation of waste to be used as fuel".

Solid fuel preparation technologies vary considerably depending on the source and type of the waste, and on the requirements of the cement industry. One important requirement results from the used transfer and firing system to convey waste fuel into a kiln:

- main firing system (at the kiln head/outlet, injection of waste fuels via lances).

Highly abrasive wastes such as dried sludge and unusual particle shapes and sizes can produce operational problems. When pneumatic transfer systems are used to convey solid waste fuel in the kiln, plugging and damage to rotating parts can be avoided (the system functions entirely without moving parts). The amount of conveying air injected into the kiln along with the waste is negligible in terms of kiln combustion stoichiometry. Greater particle size dictate large pneumatic convey lines and blowers. Therefore important processing steps are the size reduction and the soft pelletising of the waste

fuel. (typically particle size is no larger than 250 (?) mm) The advantage of compacting by soft pelletising is the improvement of flow and dosage characteristics of the fuel.

- secondary firing system (the fuel is fed via kiln inlet, the riser between the rotary kiln inlet and the lowermost cyclone stage or the calciner).

The size restriction for solid waste fuel is not important for the secondary firing system.

Even whole tyres can be introduced via the kiln inlet. Furthermore waste with high ash content can be used.

Use of Liquid Waste

Liquid waste fuels are normally prepared by blending different wastes like used solvents or waste oil with suitable caloric values in special waste management facilities. Normally only simple pre-treatment (removal of bottoms, sediments and water) is necessary. In some cases, e.g. machining oil/emulsion, chemical processes are necessary to remove metallic pollutants and additives.

Liquid waste fuels mostly are hazardous wastes. This has to be taken into account when handling (e.g. storage, feeding) liquid waste fuel. Therefore vapour recovery is used to avoid emissions of organic compounds. Vapour recovery systems are operated in a way which ensures that the flow of organic substances is permitted only upon connection of the vapour recovery system, and that the vapour recovery system and attached facilities release no gas to the atmosphere during normal operation, with the exception of releases necessary for safety reasons. More information for the use of secondary fuels see VDI 2094 chapter 4.1. For examples of waste co-incineration see annex VII.

The main types of waste fuel that have been used for co-incineration in German cement industries in 2003 and 2004 are shown in table below.

Type of waste fuel		t/a 2003	t/a 2004
Liquid waste fuel			
Waste oil	Blended waste (hazardous)	116 000	100 000
Used solvents	Blended waste, included mono wastes are to be declared with waste code (hazardous)	48 000	72 000
Solid waste fuel			
End-of-life tyres	Mono waste	247 000	290 000
Wood	Mixed waste, included mono wastes are to be declared with waste code (can be hazardous)	48 000	42 000
Animal meal	Mono waste	452 00	439 000
Sewage sludge	Mono waste	4 000	48 000

Bleaching earth	Mono waste (hazardous)	20 000	11 000
Production –specific waste	Mixed waste, included mono wastes are to be declared with waste code	626 000	862 000
Seperated fractions of mixed municipal waste	Fuel quality depending on the used processing steps	155 000	157 000

Table: Quantities of waste fuel co-incinerated in German cement industry (Daten vdz)

Waste Quality Requirements

The aim of a quality assurance is to attain and ensure constant qualities for the waste fuels used. Those fuels that are mainly produced from process related industrial wastes mono-streams are easier to handle because of their constant qualities. Calorific fractions of inhomogeneous wastes, like mixed solid wastes from different sources, separated fractions from mixed municipal waste, the monitoring requirements are set higher to attain a reliable quality with constant low pollutant input. Regular sampling and analysis of the in- and output of the waste management facility and in the delivery into cement plant are necessary.

In order to assess and control the suitability of waste materials several criteria can be applied. To start with it might be necessary to get a description of the waste materials. In this context the origin also plays a decisive role. Furthermore some key parameters like the calorific value, the chlorine and the ash content should be known. In case of pre-treated mixed fractions of municipal waste it can also be necessary to analyse the content of trace elements. In this context the main focus should be given to mercury. This trace element has a high volatility. In order to control the mercury emissions it might therefore be necessary to limit the input into the system via an applicable control procedure.

German regulators and plant operators have developed individual systems to assess and control the suitability of alternative fuels arising from mixed waste fractions. These systems are mainly focussed on the trace element content. Apart from that the chlorine content of the materials plays an important role. Chlorine may have a negative impact on the production process. The acceptable Chlorine concentration therefore depends on the individual situation on site. Typical ranges are from < 1 – 2 %. The following table depicts typical input criteria for suitable waste fuels. If an alternative material meets the following values the recovery in the clinker burning process will be environmentally sound and safe.

Trace element	Unit	Concentration
Arsenic	mg/kg	13
Cadmium	mg/kg	9
Cobalt	mg/kg	12
Chromium	mg/kg	250
Copper	mg/kg	700*

Mercury	mg/kg	0,5 – 1
Manganese	mg/kg	500
Nickel	mg/kg	100
Lead	mg/kg	400
Antimony	mg/kg	120
Thallium	mg/kg	1 – 2
Vanadium	mg/kg	25
Tin	mg/kg	70

* Higher values may occur in individual samples

These criteria should partly not be applied on wastes streams coming from well known sources (e.g. used tyres, material coming directly from industrial processes etc.). Apart from that it has to be pointed out that also other materials that do not meet all of these values can be recovered as well. In these cases it might be necessary to take plant specific aspects into consideration.

In case of co-incineration of sewage sludge the Hg-input has to be monitored regularly because of the possible mercury residues.

3.2 Use of wastes as secondary raw materials

The use of wastes as secondary raw materials in the clinker burning process involves the substitution of the oxides contained in the secondary raw materials such as calcium oxide (CaO), silica (SiO₂), alumina (Al₂O₃) or iron oxide (Fe₂O₃) for the respective raw material constituents. Other alternative materials are supplied as interground additives to the grinding plants or cement blending plant. Also, suitable industry by-product gypsum lends itself for use as a sulphate component. An overview of eligible secondary raw materials is given in the following table.

Raw material group	Examples of waste streams
Ca group	Industrial lime Lime slurries Carbide sludge Sludge from drinking water treatment
Si group	Spent foundry sand
Fe group	Pyrite cinder Synthetic hematite Red mud
Si-Al-Ca group	Fly ashes Slags Crusher fines
S group	Industry byproduct gypsum
F group	CaF ₂ Filter sludges

Main alternative raw materials are industry gypsum (428 000 t / 2004) and fly ashes (378 000 t / 2004). The feeding of gypsum take place in the blending plant. Fly ashes, generated by the

combustion of coal in power plants, can be used both as raw material in the production of clinker (mainly for its content of alumina) and as inter-ground additive for the cement. Fly ash can substitute usually 5-40 % of the Portland cement clinker. Pre-condition is a low content of unburned coal. The recoverable calorific value of carbon rich ashes (up to 20% C is possible) can be used in the cement clinker process. Other types of waste that substitute raw materials are spent foundry sand (151 00 t/2004), mill scales, soil containing oil and paper sludge.

Like ash from conventional fuels, the ash from the secondary fuels provides mineral components for the cement clinker. The ternary diagram in **Figure 1** shows the composition of different fuel ashes and secondary raw materials, for which the contents of the main components CaO, SiO₂, Fe₂O₃ and Al₂O₃ are represented. As can be seen, the clinker has a defined composition which is crucial to the characteristic hydraulic properties of the cement. This means that all raw materials and fuel ashes must be carefully matched in terms of mineral composition and feed rate to obtain the desired clinker composition.

The secondary raw materials enter the clinker burning process or the calciner via the raw meal path or via the kiln inlet and/or the calciner. During the preheating phase in the preheater, organic components may be released from the kiln feed. When processing secondary raw materials, these must therefore be checked for potential releases of volatile organic constituents and the feed point selected accordingly, i.e. kiln inlet or calciner. Alternatively, the wastes can also be subjected to thermal pre-treatment and added to the raw meal path in the burned-out state. Spent foundry sand, for example, should normally be fed to the kiln inlet. Residual organic binder used in chemically bonded sand cast systems can be decomposed in the preheater. Pre-treatment of spent foundry sand (separation of dust) can reduce the content of heavy metals.

Requirements to consider in the selection and use of waste as raw material:

- the waste consists primarily of the clinker components
- low heavy metal concentration, the content in waste fuel or primary raw material can be taken in account for the limit value
- regular monitoring of the secondary material with sampling and analysis of used wastes

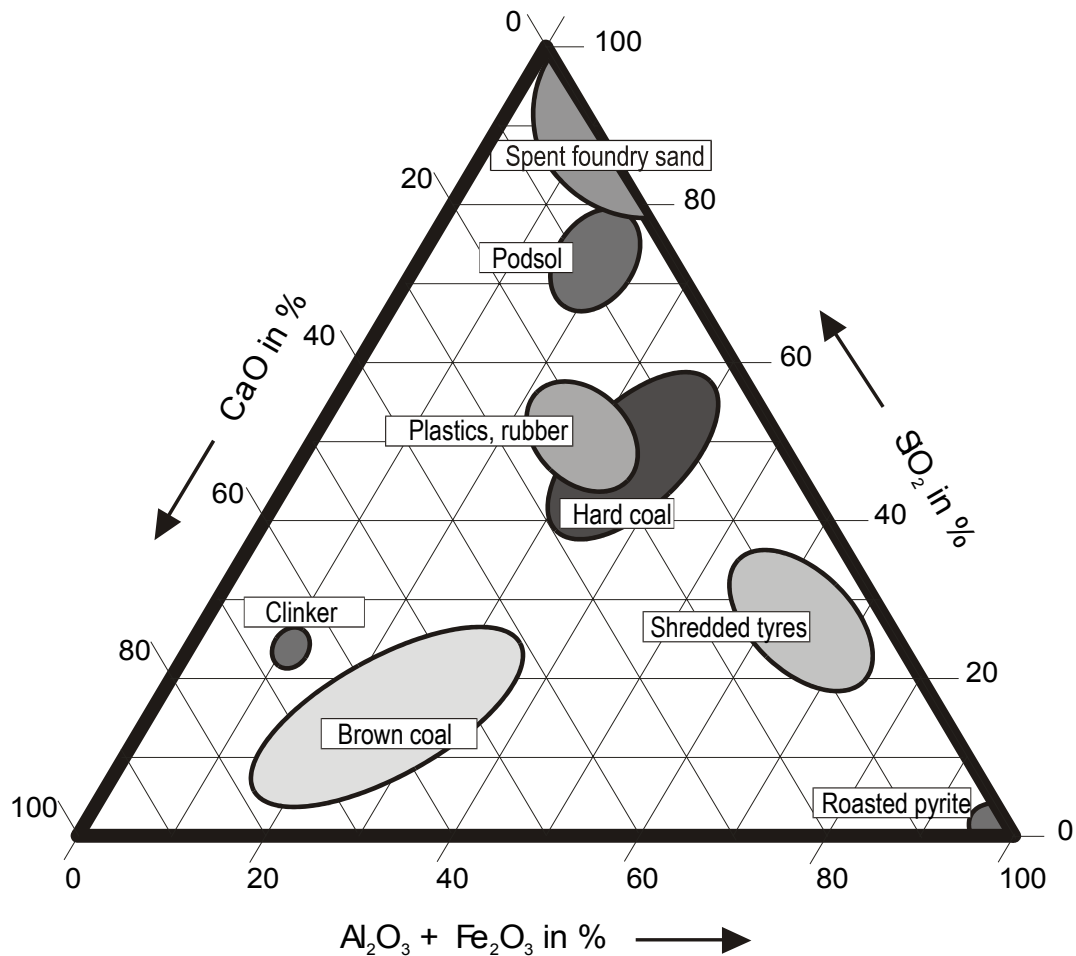


Figure 1. Ternary CaO, SiO₂ and Al₂O₃/Fe₂O₃ diagram for cement clinker and the ash constituents of different raw materials and fuels

3.3 Impacts of waste co-processing on the emission behaviour

Dust emissions from the clinker burning process remain unaffected by the co-processing of wastes.

Factors determining heavy metal emissions from the clinker production process are the behaviour of the individual heavy metals in the rotary kiln system, the input situation as well as the collection efficiency of the dust collector. The input situation is determined by the trace element concentrations in the raw materials and fuels processed. As the raw material/fuel mass ratio for clinker production is approx. 10 to 1, this means that the raw material-related inputs are decisive for the emissions. In operating practice, the processing of wastes may result in a decreased or increased total input of individual elements into the kiln system.

Because of the high retention capacity for particle-borne heavy metals of the preheater and dust collector, the co-processing of waste has only a minor influence on heavy metal emissions from the clinker burning process. Depending on the exhaust gas temperature, mercury is present in particle-borne and/or vapour form in the dust collector. To control mercury emissions, it may therefore become necessary to limit waste-related mercury inputs into the kiln system. When

firing secondary fuels recovered from mixed waste fractions, a routine receiving analysis may be required for monitoring the heavy metals input.

The inorganic exhaust gas constituents NO_x, HCl and HF remain unaffected by the choice of the feedstock. According to current knowledge, the processing of wastes in the cement production process has no significant effects on these emissions. The same applies to the emission components SO₂, CO and TOC provided that the input of volatile sulphur compounds or volatile organic compounds via the raw meal path is not increased through the processing of waste.

The combustion conditions in rotary kiln systems ensure low emission concentrations of PCDD/F (dioxins and furans). Wastes likely to contain relevant concentrations of persistent organic substances (e.g. PCB-laden spent oil) are fed via the main firing system to ensure their reliable destruction. If there are doubts about the feed point selection in the individual case, reference measurements with and without waste processing should be performed. Indications from comprehensive measurement programs are that in operating practice, PCDD/F emissions are well below the prescribed limit of 0.1 ng I-TEQ/m³, regardless of the waste processed.

3.4 Impacts of waste co-processing on product quality

The use of wastes in the clinker burning process may change the trace element concentrations in the cement product. Depending on the total input via the raw materials and fuels, the concentration of individual elements in the product may increase or decrease as a result of waste processing.

As cement is blended with aggregates (e.g. gravel, sand) for the production of concrete or mortar, it is the behaviour of the trace elements in the building material (concrete or mortar) which is ultimately decisive for evaluating the environmentally relevant impacts of waste co-processing in the clinker burning process on the product quality.

Heavy metal releases from mortar and concrete are low. Results from comprehensive tests confirm that the heavy metals are firmly trapped in the cement brick matrix. In addition, dry-packed concrete offers high diffusion resistance which further counteracts the release of heavy metals.

Tests on mortar and concrete test cubes have shown that the heavy metal concentrations in the eluates are noticeably below those prescribed by the German Drinking Water Ordinance, for instance. Storage under different and partly extreme conditions has not led to any environmentally relevant releases. This also holds true when the sample material is crushed or comminuted prior to the leaching tests.

Careful selection and monitoring of the secondary materials ensure that the co-processing of wastes does not result in heavy metal emissions of any environmentally harmful magnitude. The heavy metal emissions are partly orders of magnitude below the applicable air pollution control standards. The co-processing of waste has no negative impact on the environmental quality of the product. Under these conditions, cement can continue to be used without restrictions for mortar and concrete production. The recyclability of these materials remains completely unaffected.

The German VDZ analyses the trace element content in the German cements on a regular basis. The last values have been published for 2001. A comparison with results from earlier investigations showed that there is no increase in the trace element content of the cements although there has been a remarkable increase in the use of alternative materials over the respective period.

Annex I: Contribution to Energy Efficiency

Modification proposal concerning BREF „Cement and Lime“ Stand 12.01

1.3 Present consumption/emission levels

1.3.2 Use of energy

Chapter 3, page 23

...

The theoretical fuel energy demand for cement clinker production is determined by the energy required for the chemical/mineralogical reactions (1700 to 1800 MJ/tonne clinker) and the thermal energy needed for raw material drying and pre-heating. The actual fuel energy use for different kiln systems is in the following ranges (MJ/tonne clinker):

3000-3800 for dry process, multi-stage (3 – 6 stages) cyclone preheater and precalcining kilns,
3100-4200 for dry process rotary kilns equipped with cyclone preheaters,
3300-4500 for semi-dry/semi-wet processes (Lepol-kiln),
up to 5000 for dry process long kilns,
5000-6000 for wet process long kilns and
3100-4200 for shaft kilns.

The electricity demand is about 90-150 kWh/tonne cement.

1.4.2 Use of energy

Chapter 4, page 31:

Kiln systems with multi-stage (3 to 6 stages) cyclone preheaters with integral calciner and tertiary air duct are considered standard technology for ordinary new plants. Under optimised circumstances as during performance tests such a configuration will use 2900-3300 MJ/tonne clinker. Practical experience shows that the energy consumption of even these plants rises up to 3000-3600 MJ/tonne clinker as an annual average because of suboptimal plant utilisation and un-scheduled shutdowns and start ups of the systems. These challenging values can just be achieved by implementing thermal energy optimization measures [VDI2094] including:

Cooler

- installation of a stationary preliminary grate
- use of cooler grate plates offering a greater flow resistance to provide more
- uniform cooling air distribution
- controlled cooling air supply to the individual grate sections

Kiln

- optimized kiln firing systems
- uniform operating conditions
- optimization of process control
- near-stoichiometric, but oxidizing kiln conditions
- low thermal loading for a long refractory lining service life
- use of mineralizers
- reducing air-in leakage

Calciner

- low pressure drop

- uniform distribution of the hot meal in the kiln riser
- minimal coating formation due to low circulation of alkalis
- extensive precalcination of the raw meal
- high fuel flexibility

Preheater

- low pressure drop and a high degree of heat recuperation in the cyclones
- high cyclone collection rate
- uniform meal distribution over the gas duct cross-sections
- uniform distribution of solid and gas streams in a two-string preheater
- additional cyclone stages

Material handling

- homogenizing and even feeding of kiln feed material
- homogenizing and even feeding of fuels

But even kiln systems meeting all the afore mentioned criteria might achieve a higher energy demand because of several other impacts affecting the energy consumption of up-to-date plants with precalciners and cyclone preheaters [Cement International], e. g.:

- raw material properties like moisture content or burnability
- use of fuels with varying properties
- use of a gas bypass system
- target clinker quality
- kiln size and capacity

The local raw material situations vary widely when looking at moisture or burnability. As a matter of fact, the throughput and the moisture content of the raw materials and fuels, which have to be dried by the remaining exhaust gas heat, determine the appropriate number of cyclone stages. With a reduced need for drying heat an additional sixth cyclone stage saves about 60 MJ/tonne clinker compared to a 5 stage preheater. But in the case of water contents in the raw material of more than 8 m.-% it's cost- and also energy-effective to do without a fifth or even a fourth cyclone stage. Of course this induces higher thermal losses with the raw gas leaving the preheater. Just looking at the kiln-preheater-system a 4 cyclone preheater instead of a preheater with 5 cyclones costs about 90 MJ/tonne clinker. With only 3 cyclone stages the difference in energy demand rises further to more than 250 MJ/tonne clinker. But by using the thermal energy of the raw gas for the essential raw material drying the over-all efficiency of the whole plant is not affected.

Today it has become common practice to operate the calciner with a wide range of fuel grades, from highly reactive to extremely unreactive. Even in the kiln firing not only highly reactive but also fuels which have poor burnout behaviour as well as secondary fuels are used. A comparison between identical kiln systems fired with hard coal on the one hand and lignite on the other hand, both commonly used fossil fuels, shows a difference of nearly 100 MJ/tonne clinker due to diverse fuel qualities. The use of low reactive or coarse fuels compared to e. g. a fine ground, dry and high calorific coal might result in an additional energy demand of more than 300 MJ/tonne clinker, but inherently preserving valuable fossil resources when using byproducts or wastes.

With both raw materials and fuels chlorine, sulphur and alkalis attain to the kiln system, resulting in inner circles between kiln and preheater. At higher concentrations these cycles cause deposit formation in the area of the kiln inlet, the calciner and the two bottom stages. As a uniform kiln operation with minimised disturbances is the basis for an energy efficient clinker production, shutdowns because of coating formation should be avoided. Hence high circulation of alkalis,

chlorine and to a lower extent sulphur enforces the use of a gas bypass at the kiln inlet. By removing part of the process gas not only chlorine, sulphur and alkalis are discharged. The removal of precalcined dust and hot gas leads as a consequence to a higher specific energy consumption of about 6-12 MJ/tonne clinker per percent of removed kiln inlet gas.

While the mentioned values are valid for a kiln system with a capacity of 3000 t/d the production capacity has an influence on the energy demand as well. Burning clinker in kilns with a higher capacity of e. g. 5000 t/d saves about 100 MJ/tonne clinker while the energy consumption of smaller kilns, e. g. producing 1500 t/d, is up to 200 MJ/tonne clinker higher. These effects are mainly due to different wall heat losses per tonne of clinker produced. An evaluation of a kiln's energy consumption necessarily has to take these effects into account. In doing so a simple addition of several aspects is not suitable as they might interfere. As a conclusion the BAT level for the thermal energy consumption of a modern kiln system with cyclone preheater (3 to 6 stages depending on raw material moisture) and precalciner is a range between 3000-3800 MJ/tonne clinker.

1.5 Best available techniques for the cement industry

Chapter 5, page 48:

...

Process selection

The selected process has a major impact on the energy use and air emissions from the manufacture of cement clinker.

For new plants and major upgrades the best available technique for the production of cement clinker is considered to be a dry process kiln with multi-stage (3 to 6 stages) preheating and precalcination. Under optimised circumstances (e.g. during performance tests) the associated BAT heat balance value is 2900 to 3300 MJ/tonne clinker, depending on the production capacity and with use of high calorific fuels like coal or lignite or fuels with comparable qualities only. Local conditions like raw materials with a high moisture content or a lower burnability increase the energy demand. Also the use of fuels with different properties and the installation of a gas bypass at the kiln inlet, both BAT, result in higher energy demands. Thus practical heat balance values of 3000 to 3800 MJ/tonne clinker as yearly average values are considered as BAT:

3 stages: 3400 to 3800 MJ/tonne clinker

4 stages: 3200 to 3600 MJ/tonne clinker

5 stages: 3100 to 3500 MJ/tonne clinker

6 stages: 3000 to 3400 MJ/tonne clinker

Annex II: First waste heat power generation plant using the organic Rankine Cycle process for utilizing residual clinker cooler exhaust air

Reference Literature

E. Baatz, G. Heidt, Heidelberg/Germany, First waste heat power generation plant using the organic Rankine Cycle process for utilizing residual clinker cooler exhaust air;

Annex III

Example: Electrostatic Precipitator

Description:

In cement plants electrostatic precipitators have become successfully established for dust collection from rotary kiln exhaust gas and clinker cooler (grate cooler) exit air because of their high efficiency, low pressure loss, high availability and energy efficiency. An example of a modern EPS at a German cement kiln for the cleaning of the rotary kiln exhaust gas is given below.

ESP-characteristics:

Capacity of the kiln:	3700 t/d
Design:	4 fields horizontal
Number of filter zones:	4
Filter area:	24 247 m ²
Residence time in the electric field:	17 – 20 s
Cleaning:	mechanical / pneumatic
Exhaust gas volume:	mill off: 400 000 Nm ³ /h mill on: 490 000 Nm ³ /h
Current-strength, field 1 - 4:	ra. 2 000 Ma
Filter-voltage, field 1 – 4:	ra. 65 kV
Clean gas dust content:	< 10 mg/m ³

Operational data:

Maintenance	1 check per year
Pressure drop spray tower:	4 mbar
EPS:	2,5 mbar
Use of secondary fuels:	Up to 75 % of the energy demand can be utilized by the use of secondary fuels. The use of secondary fuels has no influence on clean gas dust content.

The size and electric power consumption of ESP's rises exponentially with decreasing clean gas dust content. ESP depend on defined raw gas conditions (temperature and humidity) for optimum operation. The lifetime of an ESP can be several decades, providing all recommended maintenance is properly carried out. Some parts, such as hammers and bearings, need regular replacement after a couple of years of operation as part of routine maintenance.

Achieved environmental benefits:

The mentioned ESP is able to achieve low emissions. The designed collection efficiency of the particulate is higher than 99.9 %, and therefore emissions of only a few mg/Nm³ can be achieved. In many cases, emissions in the range of 10 mg/Nm³ and less have been measured. The ESP is a very efficient device for collecting ultrafine particles (< 0.5 µm), providing the particles have the ability to agglomerate. The ESP is of a heavy-duty design leading to high applicability and also relatively insensitive to disturbances in the process. To preclude any operating trouble, elevated CO concentrations in exhaust gas and the resultant formation of explosive mixtures must be reliably ruled out.

Applicability:

The ESP can be used in almost every cement kiln application for the collection of particulates

from kiln exhaust gas, bypass gas dust or the exit air from grate coolers.

Economic efficiency:

Investment costs for an ESP can be fairly high. They can range from EUR 4.5 to 6 million for dedusting the kiln exhaust gas (kiln: 3000 t/d). The wide range depends on local fabrication costs, erection costs (which can vary significantly) and the size of the kiln and the ESP (which is a function of the efficiency). Operational and maintenance cost are normally low. The difference depends, to a great extent, on the local evaluation of the power consumption and maintenance costs.

Annex IV

Example: Bag Filter

Description:

Fabric filters are efficient dust collectors. Depending on the kind of cleaning, a distinction is made between rapping or shaking filters, reverse-flow filters and pulse-jet filters. Important characteristics of an filter are the size of filtering surface, the separation efficiency (higher than 99.9 %) and the resistance to filtration, the so called filter drag. This value depends on the properties of the filter medium. The basic parameter for the design of a filter is the volume flow. Therefore the filter rating has to be determined, which depends on type, amount and properties of the dust and the gas, furthermore it depends on the type of filter plant and the filter media. Typical values of filter rating are between 0.5 to 2 m³/m²min. As an example the design of a baghouse filter and its characteristics is shown in the following table.

Table: Design of the bag filter

Parameter	Units	Design
Chambers		6
Number of bags		4488
Filter area	m ²	10502
Filter rating	m ³ /m ² min	0,98
Filter material		Polyphenylen (PPS)
Exhaust gas temperature	°C	Up to 220 °C
Max. negative pressure	bar	0.88
Exhaust gas volume	Nm ³ /h	390000

The filter is made out of 6 chambers and a total of 4488 bags that are 6 m long. The total bag surface is 10502 m² and the filter rating is 0.98 m³/m² min. PPS-neededled felt is used as material that can withstand 170° C in continuous operation and temperature peaks of 200° to 220° C. The filter is used in direct operation (raw mill off) at 120° C and in interconnected operation (raw mill on) at 140° C. In the hoses there are oval three-part supporting baskets which are connected with clips. To dedust the bags a (compressed air) low pressure system is installed that works with overpressure of 0.88 bar and a cleaning air requirement of 1150 m³/h. The cleaning air is randomly blown into the bags over a rotating cleaning arm with nozzles. In front of the bags a pre-separator is installed, through which 50% of the total dust is released. Up to 75 % of the energy demand can be utilized by the use of secondary fuels. The use of secondary fuels has no influence on the clean gas dust content.

Achieved environmental benefits:

The separation efficiency is higher than 99.9 %, and therefore emissions of only a few mg/Nm³ can be achieved. Emissions in the range of 10 mg/Nm³ and less have been measured.

Applicability:

The baghouse filter can be used in almost every cement kiln application for the collection of particulates from kiln exhaust gas, bypass gas dust or the exit air from grate coolers.

Economic efficiency:

Investment costs for an baghouse filter can be fairly high. They can range from EUR 4 to 6 million for dedusting of the kiln exhaust gas (kiln: 3000 t/d). But it is not possible to predict reliably the capital expenses for baghouse filters. Even for a specific value, e.g. Euro per cubic metre of raw gas per hour, the error could be in the range of 5 to 6-digit amount. Operational and maintenance cost are normally low. The difference depends, to a great extent, on the local evaluation of the power consumption and maintenance costs.

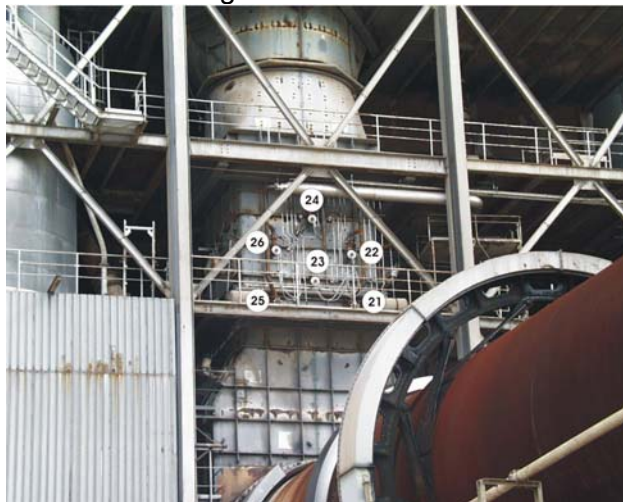
Annex V:**EXAMPLE of NO_x-reduction by the high efficiency SNCR process****Description:**

The application of the SNCR process at cement kilns has a history of more than 25 years. First operational trials showed the principal applicability of SNCR at rotary cement kilns, provided that a temperature window between 900 and 1,000 °C was given. In the 90ies, the tests were extended to numerous cement kilns in different countries (Germany, USA, Austria, Sweden, Switzerland, etc.). In most cases NO_x reduction rates of more than 50% could be achieved. Now, SNCR can be regarded as state-of-the-art or as a "Best Available Technique" (BAT) in the cement industry, as it is successfully applied at numerous cement kilns in Europe and in the USA.

At a modern dry process kiln system, which consists of a rotary kiln (5.5 x 89 m) with a fourstage, two-string preheater and planetary cooler the SNCR-process is installed since many years. The capacity is about 3 000 tpd clinker. The kiln can be fired with 100% secondary fuels. A suitable temperature window is given in the riser duct region to apply the SNCR process. The initial NO_x emission level is quite low (~ 400 - 600 mg/m³, on a daily basis). But it can also be up to 1 000 mg/m³ or more.

The ammonia water (25 % ammonia solution) is stored in a tank of 100 m³. From there it is pumped to a smaller container. From this container the injection of ammonia water, controlled by a suitable device, takes place over 8 lances (see picture 1). The arrangement of the lances is determined by the temperature profile in the riser duct.

Picture 1: Arrangement of the lances

**Achieved environmental benefits and operational data:**

The emission limit value of 500 mg NO₂/m³ could be met constantly with the installed SNCR process without any significant ammonia slip. Up to now trials were performed to investigate the optimisation of the SNCR plant, to achieve NO_x emissions below 500 mg/m³. The preliminary test results show, that NO_x values between 200 and well below 500 mg/m³ can be achieved at least temporarily when conditions were optimum. Up to now, these have, however, entailed elevated NH₃ escape. In interconnected operation (mill on) moderate ammonia emission occurs. Emissions of up to 30 mg/m³ were measured during the trials. In direct operation (mill off), they are frequently found to rise to an order of magnitude of 50 mg/m³ and may even exceed values

of 250 mg/m³ in individual cases. The NH₃ escape, occurring therefore, sets limits to the over-stoichiometric addition of reducing agent.

Applicability:

Thus, the SNCR process was advanced to become “state of the art” in the cement industry over the past 10 years. When it is combined with primary measures, it allows to achieve good reduction rates at reasonable cost. More profound investigations on the optimisation of the SNCR-Technique in the mentioned example are currently being carried out.

Economic efficiency:

c.f cost estimation in the article “NO_x Abatement”.

Annex VI: Selective Catalytic Reduction (SCR)

Description

Selective catalytic reduction (SCR) reduces NO and NO₂ to N₂ with the help of NH₃ and a catalyst at a temperature range of about 300-400 °C. This technology is widely used for NO_x abatement in other industries (coal fired power stations, waste incinerators).

In the cement industry, basically two arrangements of the SCR reactor have to be considered: low dust configuration (between dedusting unit and stack) and high dust configuration (between preheater and dedusting unit). Low dust exhaust gas systems require re-heating of the exhaust gases after dedusting, which may cause additional energy costs and pressure losses. High dust systems do not require re-heating, because the waste gas temperature at the outlet of the preheater system is usually in the right temperature range for SCR operation. But the high dust levels (100 to 200 g/Nm³) impose high demands on the durability and the operation of the catalyst.

Until now, only high dust systems have been tested in the cement industry. For high dust systems, a lot of attention has to be paid on the design and the chemical composition of the catalyst. Catalysts designed for low dust operation in other industries might not be suitable for high dust operation in a cement plant. High dust operation of an SCR reactor requires a high mechanical durability of the catalyst, a wider pitch than usual for low dust operation and an integrated dedusting system, in order to avoid plugging and activity losses. The appropriate chemical composition of the catalyst has to be evaluated by trials with high dust off-gases of cement kilns.

The first full-scale SCR demonstration plant was built in Germany with governmental financial support. This plant (Solnhofer Portland-Zementwerke) is in operation since 2001. Solnhofer Portland-Zementwerke decided to implement a high dust SCR system because of the following reasons [Sauter/Samant, 2003]:

- Lower consumption of NH₃ in comparison to SNCR, resulting in lower operational costs
- At the top of the four-stage preheater the waste gas has a temperature of 320–350 °C that is suitable for SCR and does not require re-heating (as in the case of configuration between fabric filter and stack), thus reducing energy costs and pressure loss.

The SCR reactor in Solnhofen allows the installation of 6 layers of catalytic elements, while only 3 of these layers have been in use. A layer consists of 6 modules, each with 72 catalytic elements. The catalytic elements have a size of 15x15x90 cm each, a comb-like structure and a special composition based on TiO₂ and V₂O₅. A pitch of 13 mm (10 mm in the middle layer) was chosen in order to avoid plugging. The integrated dedusting system uses preheated, high-pressure air to remove dust accumulations from the catalyst surface. The air nozzles are moved continuously over each catalyst layer, thus no service interruption is necessary to remove dust from the catalyst. By optimisation of the dedusting system, the consumption of high-pressure air was reduced from initially 100 m³/t to 18 m³ per ton of cement clinker, resulting in energy costs for the operation of the catalyst of about 0.098 € per ton of cement clinker [Sauter, 2006].

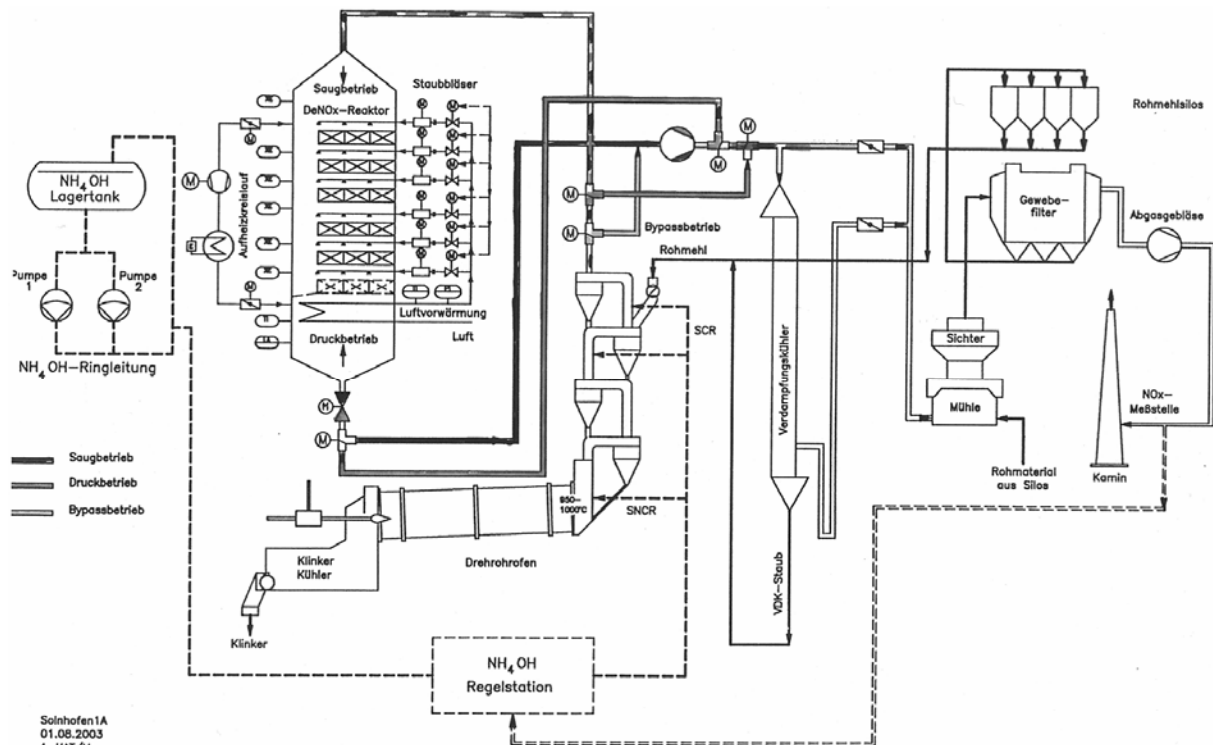


Figure 1 Flow diagram of the SCR demonstration plant at Solnhöfer Portland-Zementwerk

In order to ensure a maximum lifetime of the SCR reactor, it was designed to facilitate either upstream or downstream operation (see **Figure 1**). Accordingly, the integrated dedusting system is able to blow away dust accumulations either from the upper or the lower surface of each catalyst layer. As long-term experience in Solnhöfen did not prove expected advantages for upstream operation, there is no need for switching the gas flow direction. Accordingly, future implementations of high dust SCR could be designed for downstream operation only, thus reducing investment costs.

The reduction agent, a water solution with 25% NH₃, is added to the off-gas at the upper stages of the preheater in a molar ratio of 0.8 to 0.9 to the stoichiometric demand, according to the waste gas flow, the initial NO_x concentration and the target value.

The first set of catalysts was in operation for 40.000 h without excessive use or loss of activity. Later trials with plate-type catalysts showed higher mechanical use and unexpected losses of activity. In order to ensure full-time ELV compliance, the Solnhöfen plant was equipped with an SNCR system for backup operation in 2006. At the moment only the SNCR- technique is operated at the kiln for comparison of operational costs with the SCR.

Operational data / Achieved environmental benefits

The NO_x abatement efficiency of the SCR plant in Solnhöfen usually is in the range of 59% to 67%. Under unusual operating conditions with raw gas concentrations of 3000 mg/Nm³ and higher, NO_x abatement efficiencies of more than 80% were observed. In regular operation, the SCR reduces NO_x emissions from raw gas concentrations of 1000 to 1600 mg/Nm³ to about 400 to 550 mg/Nm³. It has to be noted that the Solnhöfen plant was designed to comply with a NO_x emission limit value of 500 mg/Nm³ and that it has been operated accordingly, but sometimes the emission limit value of 500 mg/m³ was exceeded.

With a molar ratio of 0.8 to 0.9, the consumption of NH₃ is significantly lower than by application of SNCR. It has to be noted that NH₃ from the raw material also serves as reduction agent in the reactor, thus the emission level of residual NH₃ is very low. At Solnhöfen, the SCR usually led to NH₃ emissions below 1 mg/Nm³.

In one campaign the NH_3 dosage was increased according to a target NO_x level of 200 mg/Nm^3 . In this campaign an emission level of around 300 mg/Nm^3 was achieved. These results may indicate the potential of the technique, especially as they were also achieved with 3 catalytic layers only, and the emission level of residual NH_3 was still around 1 mg/Nm^3 .

Cross-media effects

The only negative cross-media effect is a minor increase of electrical energy demand due to the internal dedusting system of the SCR reactor and additional pressure losses.

Applicability

Up to now SCR has only been tested on preheater and semi-dry (Lepol) kiln systems, but it might be applicable to other kiln systems as well.

Economics

The total investment costs of the SCR project in Solnhofen were about 3.5 million €, including extra expenditures for development reasons such as the capacity for 6 catalyst layers and the ability to operate either in upstream or in downstream mode. The investment cost of a new plant based on the Solnhofen experience are estimated to approximately 2.2 million for the SCR reactor, including ca. 250,000 € for the catalyst (to be calculated as replacement costs each 5–6 years). This amount does not include costs for ammonia storage and ductwork, as they vary significantly from site to site. In the costs for NO_x reduction by SCR or by SNCR are estimated by the German federal environmental agency (UBA) for a kiln capacity of 1,500 t/d and a NO_x reduction from 1,000 to 500 mg/Nm^3 based on practical experience from the Solnhofen plant. In the last two columns the cost estimations are extrapolated for a NO_x reduction to 200 mg/Nm^3 .

As a result of the UBA calculations, the operating costs for SNCR and SCR – including replacement costs for the catalyst – are roughly the same for a target NO_x level of 500 mg/Nm^3 , while the total specific costs for SCR are approximately 50% higher than for SNCR. At a target NO_x level of 200 mg/Nm^3 , SCR seems to be more efficient regarding operating costs, but the total specific costs are still in the same level of magnitude than for SNCR. When comparing these figures, it has to be noted that long-term experience with a NO_x level of 200 mg/Nm^3 is neither available for SCR nor for SNCR yet. In the case of SNCR, higher emissions of NH_3 also have to be taken into account.

Table 1: UBA cost comparison for NO_x abatement by SCR vers. SNCR at a 1.500 t/d cement plant

Basic assumptions	Unit	
Klinker production rate	t/a	480,000
	t/d	1,500
Operation time	h/a	7,680
Waste gas flow	Nm^3/t	2,300
Initial NO_x level	mg/Nm^3	1,000
	kg/t	2.3
NH_3 price (25% solution)	€/t	90.00
Catalyst price	€/m ³	7,500
Useful life of catalyst	H	40,000
Useful life of investments	A	20
Hurdle/inflation rate	%	3.0%

NO _x abatement system		SNCR	SCR	SNCR	SCR
NO _x target value	mg/Nm ³	500	500	200	200
NH ₃ equivalent	Kg/t	0.44	0.44	0.71	0.71
Stoichiometric factor		1.7	0.8	2.5	1.0
NH ₃ (25%) consumption	Kg/t	3.02	1.42	7.11	2.84
	Kg/d	4,550	2,150	10,650	4,250
No. of catalytic layers			3		4
Catalyst volume	M ³		33.6		44.8

Operating costs					
NH ₃ consumption	€/t	0.27 €	0.13 €	0.64 €	0.26 €
Electric energy consumption	€/t	0.03 €	0.10 €	0.06 €	0.11 €
Catalyst replacement costs	€/t		0.10 €		0.13 €
Total operating costs	€/t	0.30 €	0.33 €	0.70 €	0.50 €

Investment costs					
Ammonia system	€	600,000	250,000	1,000,000	350,000
SCR reactor (except catalyst)	€		1,950,000		2,350,000
Total investment	€	600,000	2,200,000	1,000,000	2,700,000
Specific investment costs	€/t	0.08 €	0.30 €	0.14 €	0.37 €

Total specific costs	€/t	0.38 €	0.62 €	0.83 €	0.87 €
NO _x abatement costs	€/t NO _x	330.00 €	540.00 €	450.00 €	470.00 €

A cost calculation of the German cement industry (VDZ) comprises a detailed approach concerning the costs of SCR technique [Scur, 2006]. Besides the investment costs this study considers also the whole operating costs including the costs for ammonia water, power consumption due to compressed air for the cleaning of the catalyst and the pressure drop due to the catalyst itself along with other cement plant typical economic assessment figures. Here it was shown that the costs for SNCR are always lower than those of SCR if European energy and NH₃ prices are used as a basis. Theoretically, SCR could only become less costly than SNCR at very high reduction rates, if NH₃ prices would rise extremely and energy prices would decrease. This situation however seems not be applicable for the EU region, since ammonia and energy costs are not opposing each other, as they tend to rise and concurrently fall. It could also be shown that efforts to reduce NO_x by primary measures (~ 800 mg/m³ as average now in Germany) brought about better economics for SNCR, which costs are largely influenced by the costs for ammonia.

The SCR results have shown a cost level of 1.25 to 2.00 €/t, depending on plant size and NO_x removal efficiency required. The SCR is, in contrast to SNCR, dominated by the investment costs, which are 4 to 9 times higher than for a SNCR system. Furthermore the energy consumption is essentially due to pressure drop and cleaning air for the catalyst. The latest specific figures for the SCR system are reflecting the development of the technology. As an earlier VDZ study stated 3 €/t cli. as specific costs of the SCR, this value figure has now declined to around 1.75 €/t.

Costs calculated by VDZ for a full scale installation (kiln capacity 1500 t cli./d, initial emissions of 1200 mg/m³ and a final level of 200, 500 and 800 mg/m³) is shown in table 2

Table 2: VDZ cost calculation for NO_x abatement by SCR at a 1.500 t/d cement plant

Technique	Kiln systems applicability	Reduction efficiency	Reported costs	
			Investment Mill. €	Operating €
SCR	Possibly all	85-95 %	3.2 - 4.2	0,54 - 0,94

Driving force for implementation

Implementation of SCR may be suitable to archive higher NO_x abatement efficiency or to archive simultaneous reduction of NO_x and other pollutants, e.g. ammonia and SO₂ from raw materials.

Example plant

Solnhofer Portland-Zementwerke, Frauenbergerweg 20, D-97801 Solnhofen

Reference literature

- [Sauter/Samant, 2003] G. Sauter, G. Samant: Demonstrationsanlage zur Minderung der Stickoxidemissionen in der High-Dust-SCR-Anlage mit Wabenkatalysator zur Herstellung von Zementklinker – Final report No. 50441-2/92 on the investment project funded by the German Federal Ministry of Environment and Nuclear Safety. – Not yet published.
- [Sauter, 2006] G. Sauter, Solnhofer Portland Zementwerke: Personal information, 12th April 2006
- [Scur, 2006] P. Scur, H. Hoppe: Current state of NO_x abatement with the SNCR process. Cement International, 2/2006, Vol. 4, pp. 1-11

Annex VII: Example: Co-Incineration of Alternative Fuels

Description:

The utilisation of suitable alternative fuels is of particular importance for the cement industry. Therefore alternative fuels have been used for many years. The substitution rate of alternative fuels differs from plant to plant and country to country. Today individual plants are already reaching substitution rates of more than 80%. At a modern dry process kiln system, which consists of a rotary kiln with a four-stage, twostring preheater and planetary cooler alternative fuels are used for many years. Up to 100 % of the energy consumption can be utilized by alternative fuels. Mainly tyres, waste oil, wood, treated fractions of industrial waste, such as plastics, paper or textiles and solvents are used.

As an example the accepted values for the use of industrial waste and solvents at this plant is shown in table 1.

Table 1: Example of accepted values for the use of industrial waste and solvents

Parameter	Unit	Industrial waste	Solvents
S	%	2	3 ¹⁾
Cl	%	1	1
Cd	mg/kg	10	10 ²⁾
Tl	mg/kg	1	0,5
Hg	mg/kg	0,5	1
Sb	mg/kg	75	5
As	mg/kg	10	20
Pb	mg/kg	100	700 ³⁾
Cr	mg/kg	100	100
Co	mg/kg	20	300
Cu	mg/kg	300	5
Mn	mg/kg	100	1000
Ni	mg/kg	100	10
V	mg/kg	25	0,5
Sn	mg/kg	75	1

1) Yearly average 1 mg/kg

2) Yearly average 5 mg/kg

3) Yearly average 300 mg/kg

Achieved environmental benefits:

The co-combustion of alternative fuels reduces the coal input and thus reduces the emissions of fossile CO₂.

Applicability:

Selected waste and by-products with recoverable calorific value can be used as fuels in a cement kiln, replacing a portion of conventional fossil fuels, like coal, if they meet certain specifications. Sometimes they can only be used after a certain pre-treatment to provide tailor-made' fuels for the clinker burning process. In addition to economic criteria, physical (e.g. air entrainability) and chemical (e.g. chlorine, sulphur, alkali and phosphate content, reactivity, fuel-

nitrogen content and heavy metal content) criteria play a decisive role in the selection of alternative fuels as they may have an impact on kiln operation and emissions, respectively.

Operational data:

In the following sheets the conditions and the result of the yearly emission monitoring is shown for the kiln mentioned before. During the measurement alternative fuels accounted for more than 80% of the energy input (see **table 2**). From **table 3** it becomes clear that the strict emission levels can be met.

Table 2: Operation data of the kiln (average of the data over a period of 3 days)

Day	Units	1	2	3
Time		08:00 – 18:00	08:00 – 18:00	08:00 – 18:00
Fossil fuels				
Main firing (coal dust)	t/h	2.9	3.3	2.4
Alternative fuels				
tyres	t/h	3.4	3.4	3.4
Solvents – line 1	t/h	3.0	3.0	3.0
Solvents line 2	t/h	3.0	3.0	3.0
Plastics/wood	t/h	6.3	6.3	6.3
Kiln input				
Raw meal	t/h	200	200	200
Calorific values				
coal	MJ/kg	26.8	26.8	26.8
tyres	MJ/kg	26.0	26.0	26.0
Solvents – line 1	MJ/kg	27.7	27.7	27.7
Solvents line 2	MJ/kg	26.6	26.6	26.6
Plastics/wood	MJ/kg	19.0	19.0	19.0
% of energy consumption				
coal	%	17	19	15
tyres	%	20	19	20
Solvents – line 1	%	19	18	19
Solvents line 2	%	18	17	18
Plastics/wood	%	27	28	27
Sum of alternative fuels	%	83	81	85
total	%	100	100	100
product				
clinker	t/h	121	121	121
capacity	%	97%	97%	97%

Table 3: Results of the emission monitoring during the combustion of alternative fuels

Components	Units	Results ⁽¹⁾		Emission limit value
		Mill on	Mill off	
		average	average	
Temperature	°C	106	151	---
Humidity	Vol.-%	17	17	---
Volume flow	m ³ /h	275.900	239.100	---
Dust	mg/m ³	3 ⁽²⁾		10 ⁽³⁾
NO _x	mg/m ³	385 ⁽²⁾		500 ⁽³⁾
SO _x	mg/m ³	18 ⁽²⁾		50 ⁽³⁾
HCl	mg/m ³	n.d. ⁽⁴⁾	n.d.	10 ⁽⁵⁾
HF	mg/m ³	0.09 ⁽⁵⁾	0.06 ⁽⁵⁾	1 ⁽⁵⁾
Hg	mg/m ³	0,009 ⁽⁵⁾ < 0,01 ⁽²⁾	0.033 ⁽⁵⁾ < 0,02 ⁽²⁾	0.03 (mill on) / 0.05 (mill off) ⁽³⁾
Σ (Cd, Tl)	mg/m ³	n.d.	n.d.	0.03 ⁽⁵⁾
Σ (Sb, As, Pb, Cr, Co, Cu, Mn, Ni, V, Sn)	mg/m ³	0.055 ⁽⁵⁾	0.071 ⁽⁵⁾	0.3 ⁽⁵⁾
Σ (As, Benzo-a-pyren, Cd, Co, Cr)	mg/m ³	n.d.	n.d.	0.05 ⁽⁵⁾
TOC	mg/m ³	8	9	---
PCDD/F	ng-ITE/m ³	n.d.	n.d.	0,1 ⁽⁶⁾
Benzene	mg/m ³	< 1 ⁽⁵⁾		5 ⁽⁵⁾

(1) at 1 013 hPa and 273 K; after subtraction of water content and an oxygen content in the flue gas of 10 Vol.-%.

The limit values refer to the individual sampling periods as they are given in the respective standards.

(2) yearly mean value as results of continuous measurements

(3) daily mean value

(4) n.d.: not detected

(5) mean value for sampling period of 0,5 h

(6) mean value for sampling period of 6 h

Economic efficiency:

Energy use typically accounts for 30-40% of the production costs. The costs of fuel are therefore a significant part of the costs of manufacturing cement. Waste fuels may be less expensive than primary fossil fuels although costs will vary with the type of waste and local conditions. Against these lower fuel costs alternative fuels and materials must frequently be pre-treated and made sufficiently homogeneous to be used in a cement kiln. Some additional environmental equipment may also be installed to control emissions. Special control and process measures may be needed to maintain safety, quality, and environmental standards.

Driving force for implementation:

The enormous cost pressure the cement industry is facing has led to a continual rise in the utilisation of alternative fuels over the past years. The selection of alternative fuels and materials is driven by a number of interrelated considerations, including the following main points:

- Reduction of fossil CO₂ emissions
- Reduction of the use of natural resources
- Impact on fuel cost

EXHIBIT 21

ERG No. 0195.00.002
TECQ Contract No. 582-04-65589
Work Order No. 05-06

**ASSESSMENT OF NO_x EMISSIONS REDUCTION STRATEGIES FOR
CEMENT KILNS - ELLIS COUNTY**

FINAL REPORT

TCEQ Contract No. 582-04-65589
Work Order No.05-06

Prepared by:

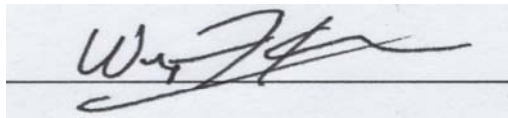
ERG, Inc.
10200 Alliance Road, Suite 190
Cincinnati, Ohio 45242-4716

Prepared for:

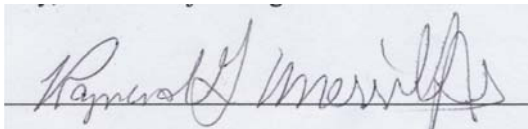
Air Quality Planning Section
Chief Engineer's Office
Texas Commission on Environmental Quality
Austin, Texas 78711-3087

July 14, 2006

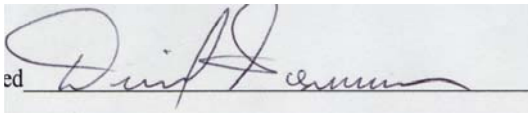
This study is the work project of a panel of experts assembled at the request of the Texas Commission on Environmental Quality. This study was performed under contract to Eastern Research Group that provided overall contract management and subcontracted the outside experts and laboratory services. While each of the experts brought specific skills to this study and was the principal author of individual sections of the report, the overall study represents a team effort. The general conclusions of the study have been reviewed and are endorsed by the entire expert panel.

A handwritten signature in black ink, appearing to read 'Walter Koucky', written over a horizontal line.

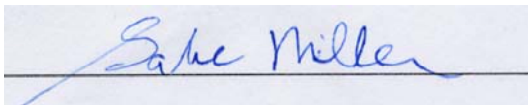
Walter Koucky, Senior Project Engineer - Contract Manager, Eastern Research Group

A handwritten signature in black ink, appearing to read 'Ray Merrill', written over a horizontal line.

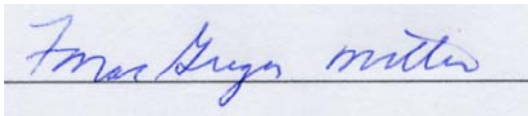
Dr. Ray Merrill, Senior Chemist, Eastern Research Group

A handwritten signature in black ink, appearing to read 'David Gossman', written over a horizontal line. The word 'ed' is visible to the left of the signature.

David Gossman, FAIC, President, Gossman Consulting Inc.

A handwritten signature in blue ink, appearing to read 'Gabe Miller', written over a horizontal line.

Dr. Gabe Miller, Professor of Chemistry, New York University

A handwritten signature in blue ink, appearing to read 'Greg Miller', written over a horizontal line.

Dr. Greg Miller, Principal, Cement Etc., Inc.

TABLE OF CONTENTS

1.0	INTRODUCTION	1-1
1.1	Executive Summary	1-2
1.1.1	Control Alternatives for Holcim Inc.	1-4
1.1.2	Control Alternatives for TXI Cement	1-5
1.1.3	Control Alternatives for Ash Grove Cement	1-5
2.0	DEFINING PARAMETERS FOR CONTROL EVALUATION	2-1
2.1	Overview of Portland Cement Manufacturing Process and NO _x Generation.....	2-1
2.1.1	Description of the Cement Industry	2-4
2.1.2	Kiln Types and Operation	2-8
2.1.3	Thermal Characteristics	2-12
2.1.4	Process Variables	2-14
3.0	NO _x FORMATION IN CEMENT KILNS	3-1
3.1	Overview of NO _x Formation Mechanisms	3-1
3.1.1	Thermal NO _x Formation	3-2
3.1.2	Fuel NO _x Formation.....	3-3
3.1.3	Feed NO _x Formation	3-5
3.1.4	Factors Affecting NO _x Emissions in Cement Manufacturing.....	3-6
3.1.5	Suspension Preheater (SP) Kilns with Riser Duct Firing.	3-9
3.1.6	Precalcining Kiln Systems.....	3-10
3.1.7	Energy Efficiency of the Cement-Making Process.....	3-11
4.0	OVERVIEW OF POTENTIALLY APPLICABLE CONTROL TECHNIQUES AND TECHNOLOGIES	4-1
4.1	High Temperature Emissions Controls.....	4-3
4.1.1	Selective Catalytic Reduction (SCR).....	4-3
4.1.2	Selective Noncatalytic Reduction (SNCR).....	4-20
4.2	Combustion Optimization.....	4-33
4.2.1	Staged Combustion of Air	4-34
4.2.2	Flue Gas Recirculation.....	4-34
4.2.3	Low-NO _x Burners	4-35
4.2.4	Staged Combustion of Fuel.....	4-38
4.2.5	Preheater/Precalciner and Tire Derived Fuel	4-38
4.2.6	Low- NO _x Precalciners	4-40
4.2.7	Mid-Kiln Firing.....	4-41
4.3	Lower Temperature Oxidation Based Technologies	4-43
4.3.1	Introduction.....	4-44
4.3.2	LoTOx TM	4-44
4.3.3	Hydrogen Peroxide	4-51
4.3.4	OXONE (Dupont – potassium monopersulfate).....	4-56
4.3.5	Sodium Acetate Process.....	4-57
4.3.6	Potential Applicability of Oxidation Technology to Ash Grove Plant..	4-59
4.3.7	Potential Applicability of Oxidation Technology to Holcim Plant	4-60
4.3.8	Potential Applicability of Oxidation Technology to TXI Plant.....	4-60

TABLES OF CONTENTS (Continued)

	Page
4.4 Process Modification	4-63
4.4.1 Combustion Zone Control of Temperature and Excess Air.....	4-64
4.4.2 Feed Mix Composition	4-64
4.4.3 CemStar Process	4-65
4.4.4 Kiln Fuel	4-67
4.4.5 Increasing Thermal Efficiency.....	4-68
4.5 Performance of Current NO _x Control Techniques and Technologies in the Cement Industry.....	4-74
4.5.1 Summary of Current Performance of NO _x Control Technologies.....	4-74
4.5.2 Summary of Current Regulations	4-74
4.5.3 Summary Of European Experiences.....	4-79
5.0 CHEMISTRY OF ELLIS COUNTY MATERIALS AND IMPACTS ON CONTROL DETERMINATIONS	5-1
5.1 Results.....	5-1
5.1.1 Organic Carbon.....	5-2
5.1.2 Total Kjeldahl Nitrogen	5-3
5.1.3 Total Sulfur	5-4
5.2 Conclusions.....	5-5
6.0 REFERENCES	6-1
Attachment A	ERG Summary of EPA 2000 NO _x Controls for Cement Kilns
Attachment B	Sampling Plan
Attachment C	ERG Report on LoTOx TM Application to Refineries
Attachment D	Summary of Current US Cement Regulations for NO _x

LIST OF TABLES

	Page
1-1 Summary of Technologies for Holcim #1	<u>1-4</u>
1-2 Summary of Technologies for Holcim #2	1-5
1-3 Summary of Technologies for TXI #1 & #4.....	<u>1-6</u>
1-4 Summary of Technologies for TXI #2 & #3.....	<u>1-7</u>
1-5 Summary of Technologies for TXI #5.....	<u>1-8</u>
1-6 Summary of Technologies for Ash Grove #1	<u>1-9</u>
1-7 Summary of Technologies for Ash Grove #2.....	<u>1-9</u>
1-8 Summary of Technologies for Ash Grove #3	<u>1-9</u>
1-9 Summary of Technologies – Seasonal for Holcim #1	<u>1-10</u>
1-10 Summary of Technologies – Seasonal for Holcim #2	1-10
1-11 Summary of Technologies – Seasonal for TXI #1 & #4	<u>1-10</u>
1-12 Summary of Technologies - Seasonal for TXI #2 & #3	<u>1-11</u>
1-13 Summary of Technologies - Seasonal for TXI #5	<u>1-11</u>
1-14 Summary of Technologies – Seasonal for Ash Grove #1.....	<u>1-11</u>
1-15 Summary of Technologies – Seasonal for Ash Grove #2.....	<u>1-12</u>
1-16 Summary of Technologies – Seasonal for Ash Grove #3.....	<u>1-12</u>
1-17 Environmental and Other Impacts of Control Technologies	<u>1-19</u>
2-1 Basic Clinker Compounds (3).....	2-3
3-1 Calculated Equilibrium Concentrations (In PPM) Of NO _x and NO _x In Air and Flue Gas (15).....	3-3
4-1.1 Summary of Modeling Results for SCR on Ellis County Kilns – Performance Results.....	4-18
4-1.2 Summary of Modeling Results for SCR on Ellis County Kilns – Economic Results ...	4-19
4-1.3 Summary of Test Results for SNCR Test.....	4-23
4-1.4 Emissions Reductions From Two Kilns Using NO _x OUT [®]	4-29

LIST OF TABLES (Continued)

	Page
4-1.5 Summary of Modeling Results for SNCR on Ellis County Kilns – Performance Results.....	4-32
4-1.6 Summary of Modeling Results for SNCR on Ellis County Kilns – Economic Results.....	4-33
4-2.1 NO _x Emissions from a Precalciner Equipped with a Low-NO _x Burner.....	4-36
4-2.2 NO _x Emissions Before and After Installation of Pyro-Jet Low-NO _x Burners.....	4-37
4-2.3 NO _x Emissions with 3 Channel and Rotaflam [®] Low-NO _x Burners.....	4-37
4-2.4 Emissions Before and After Installation of a Rotaflam [®] Burner on a Wet Kiln	4-37
4-2.5 Emissions From Kilns With Mid-Kiln Firing.....	4-43
4-3.1 Comparison Of Common Post Combustion NO _x Abatement Technologies For NO _x Emissions Control.....	4-47
4-3.2 Oxone Constituents.....	4-56
4-3.3 Reaction Steps and Pathway Equations for the Sodium Acetate Direct Absorption Process For Simultaneous NO _x And SO _x Removal (OECD, 1983).....	4-58
4-3.4 Summary of Modeling Results for LoTOx [™] on Ellis County Kilns – Performance Results.....	4-62
4-3.5 Summary of Modeling Results for LoTOx [™] on Ellis County Kilns – Economic Results.....	4-63
4-4.1 Results of Short-Term Cemstar Tests on a Preheater/Precalciner Kiln.....	4-66
4-4.2 Results of Cemstar Tests on a Wet Kiln.....	4-67
4-4.3 Summary of Modeling Results for Wet to Dry Conversion of Ellis County Kilns – Performance Results	4-73
4-4.4 Summary of Modeling Results for Wet to Dry Conversion of Ellis County Kilns – Economic Results.....	4-73
4-4.5 Summary of Modeling Results for Calciner Upgrade for Ellis County Kilns – Economic Results.....	4-74
4-5.2 National SO ₂ and NO _x Emission Limits for the Production of Cement Within the European Union (EU 15), in mg/Nm ³ , Around 2000	4-77
4-5.1 National SO ₂ and NO _x Emission Limits for the Production of Cement Within the European Union (EU 15), in mg/Nm ³	4-77

LIST OF TABLES (Continued)

	Page
4-5.2 National PM Emission Limits for the Production of Cement Within the European Union (EU 15), in mg/Nm ³	4-77
4-5.3 Midwest RPO – LADCO Study.....	4-79
4-5.4 Fall Line Air Quality Study (Georgia).....	4-79
4-5.5 NO _x Control Techniques Summary From European Best Available Techniques Report ¹	4-80

Tables in Attachments

Table A-1 ERG Summary of EPA 2000 NO_x Controls for Cement Kilns

Table B-1. Feed Chemical Composition

Table D-1. Summary of US NO_x Control Regulations for Cement Kilns – EPA 2004

NOTE: Table 4-5.1 is a separate spreadsheet that is too large for inclusion in the body of the report. It is available as an Excel spreadsheet.

LIST OF FIGURES

	Page
2-1 Temperature of the Gas and Material in the Rotary Cement Kiln 1	2-13
2-2 The Relationship Between Process Temperatures and the Chemistry of Cement Clinker Formation.....	2-13
3-1 Theoretical Equilibrium Concentrations of NO _x	3-4
4-1.1 SCR at Solnhofen Zement	4-22
4-1.2 Dependence of NO _x Reduction on Temperature for Ammonia and Urea.....	4-22
4-1.3 Application of SNCR at Holcim	4-24
4-2.1 Schematic of Preheater (58).....	4-39
4-2.2 Schematic of Precalciner(58).....	4-39
4-3.1 Overall Process Diagram of the LoTOx TM System.....	4-45
4-3.2 EDV Wet Scrubbing System with LoTOx TM Injection	4-46
4-3.3 Ideal Operating Conditions for NO _x Removal from 80% to 95%	4-49
4-3.4 Conceptual Design of Hydrogen Peroxide NO _x Control System	4-52
4-3.5 Effect of Temperature on Peroxide Oxidation of NO.....	4-53
4-3.6 Effect of Molar Ratio on Peroxide Oxidation of NO.....	4-54

1.0 INTRODUCTION

This study was conducted to explore potential NO_x emissions reduction strategies for cement kilns in Ellis County. This project included assessing existing NO_x control technologies as well as new technologies that have not been previously considered by TCEQ. This project evaluated the general performance and cost of applicable NO_x control technologies for the cement kilns present in Ellis County and further evaluated the application of these control technologies to the site-specific requirements of the kilns and raw materials present in Ellis County.

This study was initiated in order to fulfill obligations in the Dallas/Fort Worth Litigation Settlement Agreement. TCEQ, in consultation with the Plaintiffs, EPA, and Intervenor the Portland Cement Association, developed the scope of work and selected Eastern Research Group (ERG) and a panel of experts (the ERG Team) to perform this cement kiln NO_x control technologies study. This study evaluated the applicability of existing control technologies and the potential availability of new air pollution control technologies for cement kilns located in the Dallas/Ft. Worth ozone nonattainment area. This report evaluates and establishes the types of controls that may be technically applied to the three nonattainment area cement plants with specific evaluations of applicability to the 10 cement kilns located at the three plants. This report focuses largely on three active types of control technology: SCR, SNCR and NO_x Oxidation. This focus is based on the need to evaluate technologies that go beyond current requirements of 30 Texas Administrative Code (TAC) Chapter 117. Economics of these control technologies are also investigated and reported.

The intent of this study was to establish impartial parameters for the determination of applicable controls. Controls were included to the extent that they were technically feasible. Control costs and cost effectiveness values, in terms of cost per ton of NO_x controlled, were then assigned to all technically feasible controls. The ERG Team has not applied value judgments nor assessed the economic viability of technically feasible controls. The ERG Team has not excluded any control technology on the basis of cost. This study puts forward technically viable NO_x control technologies and evaluates their cost effectiveness for specific application to Ellis

County cement kilns with the intent of allowing TCEQ to have sufficient information to make control technology selections.

This report uses the USEPA report “NO_x Control Technologies for the Cement Industry” of September 2000 (EPA 2000) as a baseline for the technical analysis and as boilerplate for describing the cement industry and applicable control technologies. The ERG Team has reviewed and edited this text to reflect the Team’s understanding of the processes and control techniques. As mentioned previously, this report looks at active control technologies beyond the combustion and process optimization techniques of 30 TAC Chapter 117. The EPA 2000 report evaluates Selective Catalytic Reduction (SCR) and Selective Non-catalytic Reduction (SNCR) for the cement industry. This study takes this EPA 2000 information and updates it to the present. In addition, this study conducts site-specific evaluations including control cost evaluations for the 10 Ellis County cement kilns. This study focuses on application of SCR, SNCR and oxidation technologies including LoTOxTM to control oxides of nitrogen. Energy improvements are also examined, including replacement of the seven Ellis County wet kilns with two large, modern dry process units.

1.1 Executive Summary

The tables presented below contain summaries of control technology evaluations conducted as part of this study. The summaries below generally contain conservative costs and scenarios for the selected technologies. For example, performance levels for selective catalytic reduction (SCR) and LoTOxTM oxidation are conservatively estimated at 80-85%. These technologies typically perform better than these levels in other industrial applications. However, using a slightly lower performance value presents a more conservative evaluation of control costs, allowing potential difficulties in initial application of these technologies to Ellis County cement kilns.

The tables include a column discussing the status of the control technology for the application. This column uses the Top-Down BACT terms, *available*, *transferable* and *innovative*, to describe the statuses of the control technologies. However, for the purposes of this report, *available* essentially means that the technology is commercially available and in use

on similar types of cement kilns. *Transferable* means that the technology is commercially available and in use on similar process equipment and could reasonably be expected to work on that type of cement kiln. *Innovative* describes technologies that have not been successfully applied to a type of cement kiln, but in the judgment of the ERG Team could be expected to work on the type of cement kiln if correctly optimized through experimental application.

Wet kilns use more energy and have higher emissions rates than dry kilns. The only *available* wet kiln control technique fully evaluated in this study is conversion of the wet kilns to modern dry preheater/calcliner units. This is a high cost alternative with a cost of approximately \$11 per metric tonne (the metric tonne is the standard unit of measure for cement production and is used in this report) of clinker produced, including consideration of substantial fuel savings due to increased efficiency. As the cost of alternative controls approaches this value, there is reasonably expected to be a point where the cost of control technologies may create a substantial incentive to replace the wet kilns. This decision is complex and may require consideration of expanded production and use of alternative energy sources to be commercially justified. At the time this report was completed, Holcim of France was giving preliminary reports of trials of selective non-catalytic reduction (SNCR) on a wet kiln. While these preliminary reports do not provide sufficient information for technical evaluation of the results, this may mean that SNCR has become an available control technology for wet kilns.

Burden costs in dollars per tonne clinker produced (\$/tonne) are provided to provide insight into the impacts of control costs on the cement plant's cost of product. The emissions reductions calculated in Tables 1-1 through 1-8 are based on operation of the control equipment for the entire year and not just during the Dallas/Ft. Worth ozone season. Tables 1-9 through 1-16 are based on operation of the control equipment for just the Dallas/Ft. Worth ozone season. The metric tonne is the standard unit both in the US and worldwide for measuring cement production. This causes confusion because the metric tonne is often spelled "ton". This report uses the spelling "tonne" to refer to the metric tonne (i.e., 1,000 kilograms or 2,205 pounds). Current regulations in Texas are based on pounds of NO_x per short ton (i.e., 2,000 pounds). For consistency in the technical discussions of controls and regulations in the US and worldwide, this report discusses production related information based on the metric tonne of production. To

assist in comparison with existing Texas regulations, values in pounds per short ton have been added in parentheses to the tables in this Executive Summary.

1.1.1 Control Alternatives for Holcim Inc.

Holcim operates two modern dry preheat precalcination kilns, each with an annual production capability of slightly over one million tons per year of clinker. Holcim has recently completed testing of SNCR on these kilns. SNCR performed reasonably well on Holcim #1, but additional optimization may improve performance.

Holcim #1

Holcim's Line #1 began operation in 1987. This unit is a modern design, typical of units built in the 1980's; this kiln may be a candidate for a reconstructed preheater precalcination tower to a larger, more energy efficient design (see Section 4.4.5 of the report). This reconstruction could also allow for improved staging of combustion, lower NO_x generation and improved integration with controls such as SNCR or an oxidation control technology. Without modification, Holcim #1 will likely achieve somewhat lower control performance than Holcim #2 or TXI #5 based on application of similar technologies. However, in spite of its older generation of design, Holcim #1 is currently performing nearly as well as Holcim #2. Neither Holcim #1 nor Holcim #2 is currently performing as well as TXI #5 in terms of energy efficiency or NO_x emissions rates even though Holcim #2 is approximately the same age.

Note on the conventions used in the Tables 1-1 through 1-16.

The metric tonne (1,000 kg. or 2,205 lbs.) is used by the cement industry for measuring and reporting production. Emissions are reported in short tons containing 2,000 lbs./ton. This results in a 10% difference between the metric tonne and the short ton. A controlled emissions rate of 1.1 lbs./tonne is equivalent to a controlled emissions rate of 1.0 lbs./ton. Emissions reported in tpy are in short tons per year. As Texas has used lbs./ton (based on the US ton – or short ton) in the past, these values are provided in parentheses in appropriate locations in the tables in this chapter.

Table 1-1 Summary of Technologies for Holcim #1 – Full Year Control

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Available	2,222	3.76 (3.41)	85%	1,888.7	0.56 (0.51)	\$1,600	\$2.60
LoTOx TM	Transferable	2,222	3.76 (3.41)	85%	1,888.7	0.56 (0.51)	\$2,200	\$3.50
SNCR	Available	2,222	3.76 (3.41)	50%	1,111	1.9 (1.7)	\$1,400	\$1.30
Calcliner Upgrade	Available	2,222	3.76 (3.41)	40%	888.8	2.2 (2.0)	\$2,795	\$2.70

40% for new low-NO_x calciner based on literature.

Cost effectiveness for calciner upgrade calculated by ratio of burden costs using SCR data.

Holcim #2

Holcim's Line #2 began operation in 1999. Holcim #2 is a modern design, but emits substantially more NO_x than TXI #5 that was built only two years later. There may be process or combustion optimization options for Holcim #2 that can lower NO_x prior to control. Holcim has recently completed testing of SNCR on these kilns. SNCR did not perform as well as would be expected on Holcim #2 and additional optimization should improve performance.

Table 1-2 Summary of Technologies for Holcim #2 – Full Year Control

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Available	1,778	3.01(2.73)	85%	1,511.3	0.45(0.41)	\$1,900	\$2.20
LoTOx TM	Transferable	1,778	3.01(2.73)	85%	1,511.3	0.45(0.41)	\$2,100	\$2.80
SNCR	Available	1,778	3.01(2.73)	50%	889	1.5(1.36)	\$1,600	\$1.20

1.1.2 Control Alternatives for TXI Cement

TXI operates five kilns, one modern dry preheat precalcination kiln and four 1960's era wet kilns. Two of the wet kilns are operated full time and two are operated as backup units about 15% of the time.

TXI #1 and #4

TXI #1 began operation in 1960 and TXI #4 began operation in 1972. These are wet kilns that use the old process of making cement from wet slurry. This makes high quality cement but uses substantially more energy to make cement. Both energy use and NO_x emissions rates are substantially higher for wet kilns than for dry process kilns. Because the kilns are of similar

size and used in a similar manner, one estimate has been created to represent both TXI #1 and TXI #4. Cost and control estimates are based on averaging the operation of these kilns; a similar approach has been used for TXI #2 and #3. A control option for replacement of the wet kilns at TXI with a new large dry kiln of equal capacity to the old wet kilns is also presented. The model for wet to dry conversion contains a calculation for fuel savings that is not entirely accurate for TXI because of the use of waste fuels in the wet kilns. However, to the extent that a new, larger dry kiln would continue to utilize a similar amount of waste fuels, the savings in fuel expressed as coal, would still provide an accurate view of a potential fuel savings. The models for TXI #1 and #4 presume that mid-kiln firing will be applied as required under the current SIP and that this will achieve a 30% reduction in NO_x emissions. This 30% assumption is based on evaluation of literature and other installations and is not intended to predict the actual ability of TXI to reduce emissions through mid-kiln firing.

Assuming mid-kiln firing reduces the emissions rate from current actual rates and decreases control cost effectiveness. As less NO_x is available for control, the cost per ton controlled is increased. However, as mid-kiln firing is already required under Texas regulations, this was deemed the proper starting place for control analysis. The analyses for TXI #1 and #4 presented below are based on an average for the two kilns and values presented below, such as emissions reductions, should be doubled to account for both kilns.

Table 1-3 Summary of Technologies for TXI #1 & #4 – Full Year Control

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	838	5.67(5.14)	85%	712.3	0.85(0.77)	\$4,900	\$12.30
LoTOx TM	Transferable	838	5.67(5.14)	85%	712.3	0.85(0.77)	\$2,800	\$6.80
SNCR	Innovative	838	5.67(5.14)	35%	293.3	3.7(3.36)	\$2,100	\$2.10
Wet to Dry	Available	1,802	5.67(5.14)	65%	1,171.3	2.0(1.81)	\$6,700	\$11.00
Large 3 Kiln SCR	Transferable	1,802	5.67(5.14)	85%	1,531.7	0.85(0.77)	\$5,400	\$8.00

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace existing capacity.

TXI #2 and #3

TXI #2 began operation in 1963 and TXI #3 began operation in 1967. Similar to TXI #1 and #4, these are wet kilns that use the old process of making cement from wet slurry. Because

the kilns are of similar size and used in a similar manner, one estimate has been created to represent both TXI #2 and TXI #3. Cost and control estimates are based on averaging the operation of these kilns. Although the kilns are physically similar to TXI #1 and #4, they are used as backup units. As backup units, these kilns have a low utilization rate (averaging 15% for the two kilns in 2004); the low utilization rate will show poor economics of control, as the fixed costs will be averaged over very small NO_x reductions. The control option for replacement of the wet kilns at TXI with a new large dry kiln of equal capacity to the old wet kilns is an option for all four kilns and has identical economics and environmental benefits as described above for TXI #1 and #4. Also, as with TXI #1 and #4, mid-kiln firing is assumed as the starting place for this analysis as this is already required by Texas regulations. The analyses for TXI #2 and #3 presented below are based on an average for the two kiln and values presented below, such as emissions reductions, should be doubled to account for both kilns.

Table 1-4 Summary of Technologies for TXI #2 & #3 – Full Year Control

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	85	3.4(3.08)	85%	72.3	0.51(0.46)	\$66,400	\$14.00
LoTOx TM	Transferable	85	3.4(3.08)	85%	72.3	0.51(0.46)	\$8,000	\$11.50
SNCR	Innovative	85	3.4(3.08)	35%	30	2.2(2.00)	\$11,000	\$6.50
Wet to Dry	Available	1,802	5.67(5.14)	65%	1,171.3	2.0(1.81)	\$6,700	\$11.00
Large 3 Kiln SCR	Transferable	1,802	5.67(5.14)	85%	1,531.7	0.85(0.77)	\$5,400	\$8.00

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace existing capacity.

The higher emissions rate of TXI 1 & 4 is used as representative of operation for combined solutions wet to dry and large single SCR.

TXI #5

TXI #5 began operation in 2001 and is the largest and most efficient kiln line in the study area. It is relatively fuel efficient and intrinsically low in NO_x emissions. The low NO_x emissions rate is a function of the design and may also be partly the result of the chemistry of the feed materials (see discussion of chemistry in the main report) that may be causing reduction of NO_x. Because of the relatively low NO_x concentrations in the offgas, the expected NO_x removal efficiencies are lower for TXI #5 than for other kilns. For example, both European and US experience with SNCR indicates that removal is less efficient at lower NO_x concentration and that practical removal is currently understood to be limited to about 200 mg/m³ or 100 ppm. For

this reason, TXI #5 is modeled for 35% control for SNCR compared to 50% for the Holcim kilns.

Table 1-5 Summary of Technologies for TXI #5 – Full Year Control								
Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Available	1,710	1.50(1.36)	80%	1,368	0.30(0.27)	\$2,000	\$1.10
LoTOx TM	Transferable	1,710	1.50(1.36)	80%	1,368	0.30(0.27)	\$2,400	\$1.40
SNCR	Available	1,710	1.50(1.36)	35%	598.5	1.0(0.91)	\$2,300	\$0.60

1.1.3 Control Alternatives for Ash Grove Cement

ASH GROVE #1, #2 and #3

Ash Grove operates three wet kilns that began operation in 1966, 1969 and 1972. Similar to the wet kilns at TXI, these are wet kilns that use the older process of making cement from wet slurry. This makes high quality cement but uses substantially more energy to make cement. Both energy use and NO_x emissions rates are substantially higher for wet kilns than for dry process kilns. The Ash Grove kilns are currently complying with the SIP requirement for mid-kiln firing. The NO_x emissions rate at Ash Grove from mid-kiln firing of tires appears to be substantially lower than at TXI where the mid-kiln firing project has been delayed by permit issues.

Because the Ash Grove kilns are of similar size and used in a similar manner, separate discussions are not provided for each kiln. Slight differences in flow rates and emissions rates are modeled and presented in the tables below. Similar to the TXI presentation, a control option for replacement of the wet kilns at Ash Grove with a new large dry kiln of equal capacity to the old wet kilns is presented. A single, large SCR is modeled that combines the emissions and flow of the three kilns into one large control unit is modeled to demonstrate the impact on control costs. SCR is more cost effective at Ash Grove than at TXI due to higher gas temperatures and less required reheat of stack gas.

Table 1-6 Summary of Technologies for Ash Grove #1 – Full Year Control

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	702	5.57(5.05)	85%	596.7	0.84(0.76)	\$5,200	\$12.00
LoTOx TM	Transferable	702	5.57(5.05)	85%	596.7	0.84(0.76)	\$2,900	\$7.00
SNCR	Innovative	702	5.57(5.05)	35%	245.7	3.6(3.27)	\$2,200	\$2.20
Wet to Dry	Available	2,205	5.68(5.15)	65%	1,433.3	2.0(1.81)	\$6,500	\$11.00
Large 3 Kiln SCR	Transferable	2,205	5.83(5.29)	85%	1,874.25	0.88(0.80)	\$4,200	\$10.00

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace 3 small emissions are averaged for these scenarios.

Table 1-7 Summary of Technologies for Ash Grove #2 – Full Year Control

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	750	5.95(5.40)	85%	637.5	0.89(0.81)	\$5,200	\$13.00
LoTOx TM	Transferable	750	5.95(5.40)	85%	637.5	0.89(0.81)	\$2,900	\$7.50
SNCR	Innovative	750	5.95(5.40)	35%	262.5	3.9(3.54)	\$2,200	\$2.30
Wet to Dry	Available	2,205	5.68(5.15)	65%	1,433.3	2.0(1.81)	\$6,500	\$11.00
Large 3 Kiln SCR	Transferable	2,205	5.83(5.29)	85%	1,874.25	0.88(0.80)	\$4,200	\$10.00

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace 3 small.

Table 1-8 Summary of Technologies for Ash Grove #3 – Full Year Control

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	764	6.06(5.50)	85%	649.4	0.91(0.83)	\$5,500	\$14.00
LoTOx TM	Transferable	764	6.06(5.50)	85%	649.4	0.91(0.83)	\$3,000	\$7.90
SNCR	Innovative	764	6.06(5.50)	35%	267.4	3.9(3.54)	\$2,200	\$2.30
Wet to Dry	Available	2,205	5.68(5.15)	65%	1,433.3	2.0(1.81)	\$6,500	\$11.00
Large 3 Kiln SCR	Transferable	2,205	5.83(5.29)	85%	1,874.3	0.88(0.80)	\$4,200	\$10.00

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace 3 small.

1.1.4. Ozone Season Only Control Costs

The emissions reductions calculated in the tables below are based on operation of the control equipment during the Dallas/Ft. Worth ozone season unless otherwise noted. For example, SCR is presumed to operate only during the ozone season in the modeling. This results in a higher annualized cost effectiveness in dollars per ton of NO_x controlled as less NO_x is controlled on an annual basis. Wet kiln to dry preheat/precalcliner unit conversions provide benefit for the full year and are not seasonal measures. Tables 1-9 through 1-16 are similar to Tables 1-1 through 1-8 except that adjustments have been made to represent seasonal operation.

Holcim Ozone Season Results

Table 1-9 Summary of Technologies for Holcim #1 – Ozone Season Control

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Available	2,222	3.76 (3.41)	85%	1,267.3	0.56 (0.51)	\$1,900	\$2.00
LoTOx TM	Transferable	2,222	3.76 (3.41)	85%	1,267.3	0.56 (0.51)	\$2,400	\$2.35
SNCR	Available	2,222	3.76 (3.41)	50%	745.4	1.9 (1.7)	\$1,500	\$1.00
Calcliner Upgrade	Available	2,222	3.76 (3.41)	40%	888.8	2.2 (2.0)	\$2,795	\$2.70

Emissions reductions are for ozone season unless otherwise noted.

40% for new low-NO_x calciner based on literature.

Cost effectiveness for calciner upgrade calculated by ratio of burden costs using SCR data.

Calcliner upgrade is not a seasonal ozone measure.

Table 1-10 Summary of Technologies for Holcim #2 – Ozone Season Control

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Available	1,778	3.01(2.73)	85%	1,014.0	0.45(0.41)	\$2,000	\$1.70
LoTOx TM	Transferable	1,778	3.01(2.73)	85%	1,014.0	0.45(0.41)	\$2,300	\$1.90
SNCR	Available	1,778	3.01(2.73)	50%	596.5	1.5(1.36)	\$1,700	\$0.90

Emissions reductions are for ozone season unless otherwise noted.

TXI Ozone Season Results

Table 1-11 Summary of Technologies for TXI #1 & #4 – Ozone Season Only

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	838	5.67(5.14)	85%	477.9	0.85 (0.77)	\$5,500	\$8.90
LoTOx TM	Transferable	838	5.67(5.14)	85%	477.9	0.85 (0.77)	\$3,300	\$4.70
SNCR	Innovative	838	5.67(5.14)	35%	196.8	3.7 (3.36)	\$2,400	\$1.60
Wet to Dry Large 3	Available	1,802	5.67(5.14)	65%	1,171.3	2.0 (1.81)	\$6,700	\$11.00
Kiln SCR	Transferable	1,802	5.67(5.14)	85%	1,027.7	0.85 (0.77)	\$5,400	\$6.00

Emissions reductions are for ozone season unless otherwise noted.

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace existing capacity, emissions reduction is full year.

Table 1-12 Summary of Technologies for TXI #2 & #3 – Ozone Season Only

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	85	3.4 (3.08)	85%	48	0.51(0.46)	\$96,000	\$13.50
LoTOx TM	Transferable	85	3.4 (3.08)	85%	48	0.51(0.46)	\$11,000	\$10.50
SNCR	Innovative	85	3.4 (3.08)	35%	20	2.2 (2.00)	\$13,000	\$5.00
Wet to Dry Large 3	Available	1,802	5.67(5.14)	65%	1,171.3	2.0 (1.81)	\$6,700	\$11.00
Kiln SCR	Transferable	1,802	5.67(5.14)	85%	1,027.7	0.85 (0.77)	\$5,400	\$6.00

Emissions reductions are for ozone season unless otherwise noted.

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace existing capacity, emissions reduction is full year.

Table 1-13 Summary of Technologies for TXI #5 – Ozone Season Only

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Available	1,710	1.50(1.36)	80%	918.0	0.30(0.27)	\$2,200	\$0.87
LoTOx TM	Transferable	1,710	1.50(1.36)	80%	918.0	0.30(0.27)	\$2,600	\$0.90
SNCR	Available	1,710	1.50(1.36)	35%	401.6	1.0(0.91)	\$2,500	\$0.45

Emissions reductions are for ozone season unless otherwise noted.

Ash Grove Ozone Season Results

Table 1-14 Summary of Technologies for Ash Grove #1 – Ozone Season Only

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	702	5.57(5.05)	85%	400.4	0.84 (0.76)	\$5,800	\$9.20
LoTOx TM	Transferable	702	5.57(5.05)	85%	400.4	0.84 (0.76)	\$3,400	\$5.00
SNCR	Innovative	702	5.57(5.05)	35%	164.9	3.6 (3.27)	\$2,500	\$1.70
Wet to Dry	Available	2,205	5.68 (5.15)	65%	1,433.3	2.0 (1.81)	\$6,500	\$11.00
Large 3 Kiln SCR	Transferable	2,205	5.83 (5.29)	85%	1,257.6	0.88 (0.80)	\$4,600	\$7.80

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace 3 small, emissions reduction is full year.

Table 1-15 Summary of Technologies for Ash Grove #2 – Ozone Season Only

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	750	5.95 (5.40)	85%	427.8	0.89 (0.81)	\$5,800	\$9.90
LoTOx TM	Transferable	750	5.95 (5.40)	85%	427.8	0.89 (0.81)	\$3,500	\$5.40
SNCR	Innovative	750	5.95 (5.40)	35%	176.1	3.9 (3.54)	\$2,400	\$1.70
Wet to Dry	Available	2,205	5.68 (5.15)	65%	1,433.3	2.0 (1.81)	\$6,500	\$11.00
Large 3 Kiln SCR	Transferable	2,205	5.83 (5.29)	85%	1,257.6	0.88 (0.80)	\$4,600	\$7.80

Emissions reductions are for ozone season unless otherwise noted.

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace 3 small, emissions reduction is full year.

Table 1-16 Summary of Technologies for Ash Grove #3 – Ozone Season Only

Control Technology	Control Technology Status	Emissions Rate before control tpy	Emissions Rate before control lbsNO _x /tonne (lbsNO _x /ton)	Percent Control	Emissions Reduction from Control tpy	Controlled Emissions lbsNO _x /tonne (lbsNO _x /ton)	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
SCR	Transferable	764	6.06 (5.50)	85%	435.7	0.91(0.83)	\$6,100	\$10.60
LoTOx TM	Transferable	764	6.06 (5.50)	85%	435.7	0.91(0.83)	\$3,700	\$5.70
SNCR	Innovative	764	6.06 (5.50)	35%	179.4	3.9 (3.54)	\$2,400	\$1.70
Wet to Dry	Available	2,205	5.68 (5.15)	65%	1,433.3	2.0 (1.81)	\$6,500	\$11.00
Large 3 Kiln SCR	Transferable	2,205	5.83 (5.29)	85%	1,257.6	0.88 (0.80)	\$4,600	\$7.80

Emissions reductions are for ozone season unless otherwise noted.

SCR includes the cost of installing and operating RTO's to reheat gas after ESPs.

Wet to dry conversion analysis based on one large kiln to replace 3 small, emissions reduction is full year.

1.1.5. Summary of Performance and Cost Modeling Assumptions

The ERG Team used best engineering judgment in determining modeling parameters from the various data available. The ERG Team relied primarily on permit materials and emissions statements submitted to the State of Texas as well as material supplied by the companies in establishing the modeling parameters used to estimate control performance, cost and cost effectiveness. The ERG Team considered long term trends to derive estimated values for factors such as annual production capacity of clinker, which was adjusted by an assumed capacity factor that may be lower than current high operating levels. Values for airflows and temperatures were not always available for the proposed control device locations and values were estimated based on temperature and moisture adjustments.

Cost effectiveness is calculated for NO_x reductions only. A wet to dry kiln conversion, calciner upgrade or the addition of a scrubber will result in reduction of other pollutants. As this study is performed to assess ozone control measures, these benefits have not been included in the cost benefit analyses. A simple spray tower that would not effectively control SO₂ is priced as part of the LoTOxTM analysis for wet kilns. If a flue gas desulfurization (FGD) scrubber were added, the price would increase. However, additional benefits for other pollutants controlled would also occur. For example, adding FGD scrubbers to Ash Grove wet kilns could result in approximately 1,800 tons per year of SO₂ emissions reduction per kiln and a wet kiln conversion would result in approximately 1,300 tons per year of SO₂ reduction per kiln. Both the oxides of nitrogen and sulfur are also precursors of fine particle formation. Control technologies that remove these precursors would provide additional, unquantified benefits to regional air quality.

1.1.5.1. Kiln replacement or upgrading

Both kiln replacement and upgrading were considered for modeling of the wet kilns. Replacement is the only option actually modeled because none of the wet kilns is large enough to be practically upgraded to a semi-wet system. Conversion of wet to semi-wet systems has been shown to result in significant production increases and NO_x decreases, but fuel savings have proven to be limited. Upgrading the preheater/calciner tower on Holcim #1 was also considered as an option. This process line is somewhat older than Holcim #2 or TXI #5 and the design

somewhat less energy efficient. The assumed performance of Holcim #1 with a modern, redesigned low-NO_x preheater/calculator tower was based on the survey of the performance of recently constructed new facilities and the performance of TXI #5 which is using similar Ellis County limestone to make cement. Although Holcim #2 is approximately the same age as TXI #5, TXI #5 produces much less NO_x per tonne of clinker produced. The expert panel believed that a new, intrinsic low- NO_x designed tower for Holcim #1 should perform substantially better than Holcim #2 and more like TXI #5. The cost values for wet to dry conversions and for upgrading the design of Holcim #1, as well as the energy improvements, are taken primarily from Department of Energy reports. The emissions rates in tons per year of NO_x used in these model runs are based on the assumption that a large new modern dry preheater/calculator unit would replace several older units. At Ash Grove, where all the kilns are highly utilized, this represents a composite of all the kilns. At TXI, where primarily kilns #1 and #4 are used, the replacement model looks at the emissions from these units plus a small amount from kilns #2 and #3.

1.1.5.2. SCR

The SCR cost model is a boiler cost model developed for use on coal-fired utility boilers. The SCR model is developed from the OAQPS Cost Manual and has been applied to other processes such as refinery FCCUs with reasonable success.

For the dry kilns, the model assumes that a location for SCR can be found where reheat of the process gas is not required. This is a high dust assumption. For the wet kilns, installation is assumed to be located after the dust collectors (low dust) and that reheat of the exhaust gas will be required. The impact of reheat of the gas on NO_x emissions was examined and found to be negligible. An increase of 5 to 10 tons per year of NO_x was estimated to occur based on modeled natural gas fuel use. As the gas reheater emissions could also be controlled by the SCR, the increase would reduce to one to two tons per year and was not included in the modeling. Based on the installation at Solnhofen (see Figure 4-1.1) of the SCR on the side of the tower, it was assumed that this configuration could work at the preheat/calculator kilns in Ellis County. The wet kilns, with the SCR located after the particulate controls were also assumed to have adequate

space available. The reheat cost model is based on the OAQPS cost model for regenerative thermal oxidizers with 70% heat recovery.

Although current assumptions for coal-fired power plants would predict 90% or better control for SCR, this assumption has been lowered to 85% for these model runs. This was done to represent a conservative approach to the cost modeling that included consideration of potential problems in applying SCR, such as higher variability of the gas stream comparing a utility boiler to a cement plant, and lack of experience in achieving high levels of control using SCR in the cement industry. Due to the lower emissions rates at TXI #5, the control efficiency was modeled at 80%. This was based on the evaluation of the current relatively low concentrations of NO_x in the TXI stack and uncertainty about SCR performance in a cement kiln at very low endpoint concentrations. These control efficiencies are not intended to define the final performance of this technology, but to evaluate costs under conservative assumptions. The actual decrease in performance, if any occurs, cannot be determined in advance. In the application of SCR to coal-fired boilers, higher levels of performance are typically achieved by increasing the amount of catalyst, and, thereby increasing the contact between reagent and catalytic material. Achieving higher control efficiencies increases the initial capital cost and maintenance costs for the unit. The lower performance rates were selected for the purposes of the cost modeling based on the engineering judgment of the expert panel and may not reflect the final capability SCR if installed at these locations.

1.1.5.3. SNCR

The SNCR cost model is also a boiler cost model developed for use on coal-fired utility boilers. The SNCR model is derived from the OAQPS cost manual and EPA's OTAG cost modeling. It has been simplified to obtain capital costs primarily on flow rates. The ERG team attempted to verify the reasonableness of these models' results for the Ellis County dry kilns. The estimates for wet kilns are conjecture. No accurate costing can be developed without an understanding of the ultimate design of the control system. Limited information on installation of SNCR on a wet kiln in France suggests that this is a technically feasible option. Lacking any detailed information on the unit in France, controls costs were estimated based on the dry kiln

model. Reagent costs are a substantial part of the annualized cost of SNCR, so this rough cost estimate for wet kilns was still considered to be a valuable approximation.

As with the SCR control efficiencies, the cost models were run at conservative control efficiency values. A value of 50% was used for the Holcim kilns and 35% was used for TXI #5 and the wet kilns. The control efficiency of 35% at TXI was consistent with the reported performance of a European application at approximately 100 ppm. The value for wet kilns represented a reduced expectation for this experimental approach. The performance rates were selected for the purposes of the cost modeling based on the engineering judgment of the expert panel and may not reflect the final capability of SNCR if installed at these locations.

1.1.5.4. Oxidation Technologies

LoTOx™

The LoTOx™ model is based on the OAQPS model for thermal oxidation. Specific inputs to this model were developed with assistance from the BOC Group, PLC (BOC) and should produce results reasonably close to the current costs of their oxidation technology. For the dry process kilns, no scrubbers were assumed to be required as the existing scrubbers were expected to be sufficient for removal of oxidation products from the process gas. For the wet kilns, BOC provided approximate costs for installing LoTOx™ with spray towers. BOC provided generalized costs; detailed estimates on scrubber operating costs have not been developed. No cost model runs were performed for single LoTOx™ units to control multiple kilns as was done for SCR. The LoTOx™ cost model does not have the same benefit of scale for larger units as does SCR. Because little or no cost benefit would be predicted from a single, large LoTOx™ unit, no cost estimates were done for combined control of multiple kilns.

The same control efficiencies were used for LoTOx™ as for SCR. Again, this was done to make the cost estimates conservative due to lack of application of these technologies to the cement industry. BOC asserted that control efficiencies of 95% and 98% could be obtained using this technology. However, for this modeling effort, the same performance levels were modeled for LoTOx™ as for SCR. As with the SCR modeling, this was not done as a reflection

on the final performance capability of the technology, but rather to provide an equivalent and conservative basis for evaluating the cost of control.

The accuracy of OAQPS cost modeling approaches is typically within 30% or so for instances where parameters are accurately defined and the process well known. This is a useful tool for comparing different technologies. However, closely scrutinized vendor quotes should be the basis of any final comparison of technologies. Minor differences in modeling results are likely to be the product of assumptions regarding cost of electricity or reagents. For example, for Holcim #2, the cost of SCR was predicted to be \$1,700 per ton of NO_x and LoTOxTM was modeled at \$2,100 per ton.

A relatively small difference in the cost effectiveness for SCR and LoTOxTM should not be viewed as significant without understanding the contributing factors. Reagent cost and control efficiency assumptions can account for these differences. Cost for ammonia reagent is currently very volatile due to relatively high natural gas costs. A value of \$500 per ton was used to reflect higher costs experienced in 2005, but not the currently higher short-term prices. If current high prices persist, the cost difference between these two technologies would be negligible. If LoTOxTM proves better at responding to fluctuations in NO_x concentrations and achieves a higher level of control than SCR, this would also tend to push cost effectiveness of the two technologies closer together. Differences of 20% in the cost effectiveness of two technologies should not be a basis for selecting one technology over another. If initial modeling results produce similar economic and performance values, both technologies should be considered for vendor pricing unless other factors dictate a clear preference for one over the other. Other factors, such as a determination that reheat was needed for application of SCR to dry kilns, would have a substantial impact and the two technologies would no longer appear equivalent in cost effectiveness.

Other Oxidation Technologies

There are other oxidation technologies using hydrogen peroxide or other chemical reagents. Most of these technologies are new; relatively low temperature end-of-pipe control techniques. As mentioned under the discussion for SCR above, the cost for ammonia reagents is

currently higher than it has been historically. Other oxidation technologies may allow use of lower cost reagents that may improve cost effectiveness for plants with existing wet scrubbers. There is one higher temperature hydrogen peroxide technology that may be able to be implemented inside an existing precalciner system, although it still requires a wet scrubber. At current hydrogen peroxide commodity prices, one of these alternative technologies may be more cost effective than ozone or ammonia based reagent alternatives. None of these technologies was found to have been used on a cement kiln or comparable system. Therefore, costing of these options was not attempted. All of these systems should be considered innovative but should not be ruled out of consideration, as a lower cost reagent would have a substantial impact on annual control costs.

1.1.6. Evaluation of Chemistry and Process Variables on NO_x Formation

As part of the overall evaluation of the potential to control, correlate and predict NO_x formation in the Ellis County Kilns, short-term process and emissions data were evaluated. These analyses were performed on data that was considered confidential business information and are, therefore, not summarized or reported. The statistical correlations evaluated included comparison of NO_x emissions rate to:

- Kiln Feed of SiO₂,
- Al₂O₃,
- Fe₂O₃,
- CaO,
- MgO,
- SO₃,
- Na₂O,
- K₂O passing 200 mesh,
- Clinker K₂O,
- Production rate,
- Coal/Coke passing 200 mesh,
- Chain zone temp, and
- Kiln drive amps.

In addition, graphs were produced looking at the relationships between gaseous pollutants and NO_x emissions rate. The conclusion of this investigation was essentially negative. None of the

process parameters and relations to formation of gaseous pollutants that were evaluated produced any relationships that indicated the potential for further control of NO_x beyond the control measures already in place (with the exception of the wet kilns at TXI that are not yet permitted for mid-kiln injection while burning hazardous waste). Furthermore, these parameters did not indicate that changes in feed constituents had an adverse or positive correlation to NO_x emissions rate.

This investigation did not show any correlations between feed and process materials and NO_x formation rates that would prohibit the use of the control technologies and techniques reviewed in this report. This investigation did not show any direct relationships between feed materials and NO_x formation rates that could potentially be exploited to further reduce NO_x emissions rates through process modifications. However, one interesting aspect of the investigation of the chemistry of the feed materials was a strong suspicion that nitrogen bearing feed materials present in Ellis County may be producing some limited non-selective non-catalytic reduction of NO_x. The exact nature of the material was not identified in this study. Similar effects have been noted in other kilns being fed materials such as nitrogen bearing sands. This may help to explain the current low NO_x emissions rates of TXI #5. This is discussed in Section 5.2 of this report. The chemical analyses of the feed materials was requested by the three plants to be treated as confidential business information and the site specific information is not included in this report for that reason. Generally summaries of the overall characteristics based on averages for all three plants are presented in Sections 5.1 and 5.2 of this report.

1.1.7. Summary of Environmental and Other Impacts

Sampling of the materials fed to the kilns was conducted and is summarized in Section 5 of this report along with characterizations of the kiln feed materials supplied by the cement plants. This testing showed that the materials fed to the Ellis County kilns was substantially uniform for the purposes of evaluating the impacts of feed materials on control equipment. Although there was variation, the variation between different samples, wet and dry kiln feed and the different Ellis County plants was not considered by the experts evaluating the individual control technologies to be significant enough to impact any of the control determinations. The main concerns were levels of sulfur and organics in the feed materials and the resulting

concentration of sulfur oxides, hydrocarbons and, additionally, carbon monoxide in the process gas streams emitted by the kilns and precalciners. These concerns and potential impacts are discussed under Section 4 of this report to the extent that these issues needed to be specifically evaluated in considering application of any of the control technologies to Ellis County kilns. For example, the concentrations of sulfur dioxide in the gas streams of the Ellis County kilns are discussed in Section 4.1.1 in comparison to levels where selective catalytic reduction has been applied to electric utility boilers.

The potential impacts are summarized and compared in Table 1-17 below for all of the major control options considered in this report. To the extent that issues such as reagent release to the atmosphere (slip) or clogging and/or corrosion resulting from reagents or reactions in process and control equipment were concerns in applying control technologies in Ellis County, these issues are also discussed in Section 4 of this report. Table 1-17 summarizes and compares potential impacts to allow comparisons between technologies.

Table 1-17 Environmental and Other Impacts of Control Technology				
Impact	Selective Catalytic Reduction	Selective Non-Catalytic Reduction	Oxidation Technologies	Kiln Modernizations
Process Chemistry Limits Application of Control Technology in Ellis County	Ellis County chemistry within limits ^a	Ellis County chemistry within limits ^a	Ellis County chemistry within limits ^a	Chemistry not a factor
Release of Additional Criteria Pollutants	Accelerated formation of PM _{2.5} ^b	Accelerated formation of PM _{2.5} ^b	Possible decrease in VOCs, scrubbers can produce co-control of SO _x and other pollutants ^c	Potential large decreases unless capacity increased ^d
Reagent Release to the Atmosphere	Possible ammonia slip < 5 ppm ^e	Possible ammonia slip < 10 ppm ^e	Reactive reagents unlikely to "slip"	No
Clogging and/or Corrosion Potential	Possible depending on location ^f	Possible depending on location ^f	Possible - scrubber & ducts design ^g	No
Formation of Solid or Hazardous Pollutants	Periodic removal of ammonia salt deposits ^h	Periodic removal of ammonia salt deposits ^h	No, potentially can decrease emissions of organics.	No
Formation of Wastewater Contaminants	No	No	Probably used onsite as fertilizer ⁱ	No

Explanation of notes in Table 1-17.

a The constituents in feed materials and gaseous pollutant concentrations have been evaluated by the experts for each control technology and determined to be within acceptable limits for deploying the control technology on Ellis County kilns.

b Presence of "slip" ammonia reagent is expected to form sulfate and nitrate fine particles closer to the stack and may cause increased opacity at the stack. However, this is not a "new" pollutant in that the precursor pollutants released by cement kilns will tend to form fine particles in the atmosphere using atmospheric ammonia. The excess ammonia from SCR and SNCR will cause formation to occur closer to the stack. Excess opacity with the raw mill off-line may be exacerbated using SNCR. This occurs in units that do not use SNCR and wet lime injection has been suggested as a control measure.

c Oxidation technologies can also oxidize hydrocarbons, particularly the higher temperature peroxide-based control technologies. These technologies have the potential to reduce VOC emissions. Oxidation technologies also require the use of a scrubber to remove oxidized pollutants and the scrubber can also be designed to control pollutants such as SO₂ and acid mists.

d The major "modernization" projects considered in this report were wet to dry kiln conversion and efficiency improvements for the older dry kiln at Holcim. Efficiency improvements result in substantial energy savings and emissions reductions. However, these options require large capital investments that may only be economically justified by production increases that could negate the efficiency improvements and emissions reductions.

e In preheater/calcliner units, recent German experience suggests that most of the ammonia ends up in the raw meal during drying and grinding and is not released to the atmosphere. As discussed above under footnote "b", this recycling of ammonia and ammonia salts may result in increased opacity when the raw mill is off-line.

f SCR is not likely to produce corrosive byproducts. The potential for clogging is discussed below as sulfate deposits.

g As the cement kiln exhaust gas steam is typically moist, oxidation products can become hydrated and acidic prior to removal in the scrubber. Depending on the reagent and injection location selected, this may require replacement of ductwork and components with more corrosion resistant materials.

h Periodic removal of deposits of ammonia salts (ammonium sulfate/chloride) may be required from equipment downstream of SCR and SNCR ammonia injection points. In preheater/calcliner units, recent German experience suggests that most of the ammonia ends up in the raw meal during drying and grinding and is not released to the atmosphere. To the extent that ammonia salts form primarily in the raw mill, this limits potential downstream problems except when the raw mill is off-line.

i Scrubber waters rich in nitrates could be used on-site as fertilizer to promote plantings used to control wind erosion in and around quarry areas.

2.0 DEFINING PARAMETERS FOR CONTROL EVALUATION

This section of the report is taken from the EPA 2000 Report and is included, with minor editing by the ERG Team. This information is included to provide the Texas environmental communities with the comprehensive background information necessary to understand the parameters that dictate NO_x control options at cement kilns.

2.1 Overview of Portland Cement Manufacturing Process and NO_x Generation

Portland cement, a fine gray or white powder, is the generic term for the type of cement used in virtually all concrete, which is a mixture of aggregates (e.g., crushed stone, gravel, sand), water, and cement. The American Society for Testing and Materials (ASTM) defines Portland cement as "hydraulic cement (cement that not only hardens by reacting with water but also forms a water-resistant product) produced by pulverizing clinkers consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an inter ground addition."

In 2004, the Portland cement industry in the U.S. consisted of 114 facilities in 37 States (and two facilities in Puerto Rico). Approximately 90 million tons of Portland cement were produced in 2004, with California, Texas, Pennsylvania, Michigan, Missouri, and Alabama accounting for approximately 50 percent of the production (1).

Hydraulic Portland cement, the primary product of the cement industry, is made from clinker blended with gypsum. Clinker is produced by heating a mixture of limestone, clay, and other ingredients to incipient fusion at a high temperature. Limestone is the single largest ingredient required in the cement-making process, and most cement plants are located near large limestone deposits. Portland cement is used in almost all construction applications including homes, public buildings, roads, industrial plants, dams, bridges, and many other structures.

In the cement-making process, the solid raw materials are heated to their fusion temperature, typically 1400 to 1500 EC (2550 to 2750 EF), by burning various fuels such as coal. Portland cement has been defined as "a hydraulic cement produced by pulverizing Portland

cement clinker and usually containing calcium sulfate.”(2) Portland-cement clinker has been defined as “a clinker, partially fused by pyroprocessing, consisting predominantly of crystalline hydraulic calcium silicates.”(2) Burning an appropriately proportioned mixture of raw materials at a suitable temperature produces hard fused nodules called clinker, which are further ground to a desired fineness.

Five types of Portland cement are recognized in the United States which contain varying amounts of the basic clinker compounds given in Table 3-1. (3) Different types of cements are produced by starting with appropriate kiln feed composition, blending the clinker with the desired amount of calcium sulfate, and grinding the product mixture to appropriate fineness. Manufacture of cements of all of the various types involves the same basic high temperature fusion and clinkering process responsible for the NO_x emissions from cement kilns.

The five basic types of Portland cement recognized and produced in the United States are described below. (3,4) In addition, different varieties are prepared by using various blending formulations. (5)

Type I Portland cement is a normal, general-purpose cement suitable for all uses. It is used in general construction projects such as buildings, bridges, floors, pavements, and other precast concrete products. Type I is also known as regular cement and most commonly known as gray cement because of its color. White cement typically contains less ferric oxide and is used for special applications. There are other types of cements in general use such as oil-well cement, quick-setting cement, and others for special applications. Type IA Portland cement is similar to Type I with the addition of air-entraining properties.

Table 2-1. Basic Clinker Compounds (3)

Formula	Name
$2\text{CaO} \cdot \text{SiO}_2$	Dicalcium silicate
$3 \text{CaO} \cdot \text{SiO}_2$	Tricalcium silicate
$3\text{CaO} \cdot \text{Al}_2\text{O}_3$	Tricalcium aluminate
$4\text{CaO} \cdot \text{Al}_2\text{O}_3 \cdot \text{Fe}_2\text{O}_3$	Tetracalcium aluminoferrite
MgO	Magnesium oxide in free state or combined in di- or tri-calcium silicate lattice.

Type II Portland cement generates less heat at a slower rate and has a moderate resistance to sulfate attack. Type II Portland cements are for use where moderate heat of hydration is required or for general concrete construction exposed to moderate sulfate action. Type IIA Portland cement is identical to Type II, with the exception of inclusion of an air-entraining admixture, and produces air-entrained concrete.

Type III Portland cement is a high-early-strength cement and causes concrete to set and gain strength rapidly. Type III is chemically and physically similar to Type I, except that its particles have been ground finer. It is made from raw materials with a lime to silica ratio higher than that of Type I cement. It contains a higher proportion of tricalcium silicate ($3\text{CaO} \cdot \text{SiO}_2$) than regular Portland cements. Type IIIA is an air-entraining, high-early-strength cement.

Type IV Portland cement has a low heat of hydration and develops strength at a slower rate than other cement types, making it ideal for use in dams and other massive concrete structures where there is little chance for heat to escape. Type IV Portland cement contains a lower percentage of tricalcium silicate ($3\text{CaO} \cdot \text{SiO}_2$) and tricalcium aluminate ($3\text{CaO} \cdot \text{Al}_2\text{O}_3$) than type I, thus lowering the heat evolution. Consequently, the percentage of dicalcium silicate is increased substantially and the percentage of tetracalcium aluminoferrite ($4\text{CaO} \cdot \text{Al}_2\text{O}_3 \cdot \text{Fe}_2\text{O}_3$) may be increased or may stay the same.

Type V Portland cement is used only in concrete structure that will be exposed to severe sulfate action, principally where concrete is exposed to soil and groundwater with a high sulfate content. Type V Portland cements are those which, by their composition or processing, resist sulfates better than the other four types.

The use of air-entraining agents increases the resistance of the hardened concrete to scaling from alternate freezing and thawing. By adding these materials to the first three types of cements, IA, IIA, and IIIA varieties of cements are produced. Additional varieties of cements are produced for special applications by blending different ingredients: masonry cement, expansive cement, oil-well cement, etc. Masonry cements are commonly finely ground mixtures of Portland cement, limestone, and air-entraining agents. Granulated blast furnace slags and natural or artificial pozzolans are mixed and interground with Portland cement to prepare still other varieties such as blended types IP, IS, S, I(PM), and I(SM). (5)

2.1.1 Description of the Cement Industry

About 77.6 million metric tons of gray Portland and 274,000 metric tons of white cement were produced in a total of 198 cement kilns at 118 plants in the United States in 1998. (6) This was a 6.0 percent increase from the 1990 reported total production of 73.5 million metric tons. As shown in Figure 3-1, cement industry annual clinker capacity steadily declined from the 1975 peak through 1990 and has steadily increased since the 1990 low. While the number of kilns has dropped sharply, average kiln size has increased. Since 1973 when average kiln size was 173,000 metric tons, average kiln size has now reached 393,000 metric tons. Although 42 cement companies produced clinker in 1998, the top 5 companies provided about 44.2 percent of the total finish grinding capacity. This is evidence of a high concentration of the U.S. production among a limited number of top producers. Table 2-2 provides a list of all companies along with their share of the total clinker production. Table 2-3 lists the clinker producing capacity in the United States by States. The locations of the operating kilns are shown in Figure 2-2. California and Texas are the two largest states in terms of clinker capacity with Pennsylvania, Missouri, and Alabama rounding out the top five. Fourteen states and the District of Columbia had no cement clinker-producing plants in 1998. (6)

The large majority of the cement plants (about 82.4 percent) in the United States are coal fired with about 2.8 percent using natural gas, and 0.9 percent using oil as the primary fuel. (6) The remaining 13.9 percent of the plants used other combinations, e.g. coal/waste as primary

fuel. In 1998, 11 plants used waste as a primary fuel with 49 plants reporting waste as an alternate fuel.

Overview of Cement Manufacturing Process

The process of Portland cement manufacture consists of: (7)

- Quarrying and crushing the rock;
- Grinding the carefully proportioned materials to high fineness;
- Subjecting the raw mix to pyroprocessing in a rotary kiln; and
- Grinding the resulting clinker to a fine powder.

A layout of a typical plant is shown in Figure 3-3, which also illustrates differences between the two primary types of cement processes: wet process and dry process. (7) Newer designs of dry process plants are equipped with innovations such as precalciners and/or suspension preheaters to increase the overall energy efficiency of the cement plant. (7) Figure 34 is an illustration of a preheater/precalciner type of dry process system. (8)

The choice between the wet or dry process for cement manufacturing often depends upon the moisture content in the raw feed materials mined from quarries. If the moisture content of the feed materials is already very high (15 to 20 percent), a wet process may be attractive. The recent trend, however, has been toward the dry process with preheater/precalciner systems. In 1998, about 20.6 million metric tons of clinker were produced by the wet process with 57.4 million metric tons produced by a dry process. Within the dry process category, 14.2 million metric tons were produced by facilities equipped with a preheater system and 26.1 million metric tons were produced by facilities equipped with a precalciner system. (6)

The different steps involved in the cement manufacturing process are described in the following subsections.

Raw Materials and Kiln Feed Preparation

Calcium carbonate and the oxides of silicon, aluminum, and iron comprise the basic ingredients of cement raw mix. Because of the large requirement for calcium, the plants are

generally located near the source of the calcareous material. The requisite silica and alumina may be derived from a clay, shale, or overburden from a limestone quarry. Such materials usually contain some of the required iron oxide, but many plants need to supplement the iron with mill scale, pyrite cinders, or iron ore. Silica may be supplemented by adding sand to the raw mix, whereas alumina can be furnished by bauxites and alumina-rich flint clays. (7) Industrial byproducts are becoming more widely used as raw materials for cement, e.g., slags contain carbonate-free lime, as well as substantial levels of silica and alumina. Fly ash from utility boilers can often be a suitable feed component, since it is already finely divided and provides silica and alumina.

The bulk of raw materials originates in the plant quarry. A primary jaw or roll crusher is frequently located within the quarry and reduces the quarried limestone or shale to about 100 mm top size. A secondary crusher, usually roll or hammer mills, typically gives a product of about 10 to 25 mm top size. Combination crusher-dryers can utilize exit gases from the kiln or clinker cooler to dry wet material during crushing. Each of the raw materials is stored separately and proportioned into the grinding mills separately using weigh feeders or volumetric measurements. Ball mills are used for both wet and dry processes to grind the material to a fineness such that only 15 to 30 wt% is retained on a 74- μm (200 mesh) sieve.

In the wet process the raw materials are ground with about 30 to 40 percent water, producing a well-homogenized mixture called slurry. Raw material for dry process plants is ground in closed-circuit ball mills with air separators, which may be adjusted for the desired fineness. Drying may be carried out in separate units, but most often is accomplished in the raw mill simultaneously with grinding. Waste heat can be utilized directly in the mill by coupling the raw mill to the kiln- and/or clinker cooler exhaust. For suspension preheater-type kilns, a roller mill utilizes the exit gas from the preheater to dry the material in suspension in the mill. A blending system provides the kiln with a homogeneous raw feed. In the wet process the mill slurry is blended in a series of continuously agitated tanks in which the composition, usually the calcium oxide content, is adjusted as required. These tanks may also serve as kiln feed tanks or the slurry may be pumped to large kiln feed basins. Dry process blending is usually accomplished in a silo with compressed air. (7)

Pyroprocessing

All cement clinker is produced in large rotary kiln systems. The rotary kiln is a refractory brick-lined cylindrical steel shell [3 to 8 m (10 to 25 ft) diameter, 50 to 230 m (150 to 750 ft) long] equipped with an electrical drive to rotate the kiln on its longitudinal axis at one to three rpm. It is a countercurrent heating device slightly inclined to the horizontal, so that material fed into the upper end travels slowly by gravity to be discharged into the clinker cooler at the lower, discharge end. The burners at the firing end, i.e., the lower or discharge end, produce a current of hot gases that heats the clinker, and the calcined and raw materials in succession, as it passes upward toward the feed end. Refractory bricks of magnesia or alumina combinations line the firing end. In the less heat-intensive midsection of the kiln, bricks of lower thermal conductivity are often used. Abrasion-resistant bricks or monolithic castable linings are used at the feed end. (7)

Pyroprocessing may be conveniently divided into four stages, as a function of location and temperature of the materials in the rotary kiln. (9)

1. Evaporation of uncombined water from raw materials, as material temperature increases to 100°C (212°F);
2. Dehydration, as the material temperature increases from 100°C to approximately 430°C (800°F) to form dehydrated clay minerals composed of oxides of silicon, aluminum, and iron;
3. Calcination, during which carbon dioxide (CO₂) and CaO are formed from calcium carbonates, primarily between 900°C (1,650°F) and 982°C (1,800°F); and
4. Reaction, of the oxides in the burning zone of the rotary kiln, to form cement clinker at temperatures of approximately 1,510°C (2,750°F).

The duration and location of these stages in an actual kiln depend upon the type of process used, e.g., wet or dry, and the use of preheaters and precalciners as discussed in the following section.

It is desirable to cool the clinker rapidly as it leaves the burning zone. Heat recovery, preheating of combustion air, and fast clinker cooling are achieved by clinker coolers of the

reciprocating-grate, planetary, rotary, or shaft type. Most commonly used are grate coolers where the clinker is conveyed along the grate and subjected to cooling by ambient air, which passes through the clinker bed in cross-current heat exchange. The air is moved by a series of undergrate fans and becomes preheated to 370 to 1,000°C (700 to 1,830°F) at the hot end of cooler. A portion of the heated air serves as secondary combustion air in the kiln. Primary air is that portion of the combustion air needed to carry the fuel into the kiln and disperse the fuel. (7)

2.1.2 Kiln Types and Operation

There are four main types of kilns used in Portland cement manufacture:

- Long wet kilns;
- Long dry kilns;
- Dry kilns with preheaters; and
- Dry kilns with precalciners.

Wet kilns tend to be older units and are often located where the moisture content of feed materials from local sources (quarries) tends to be high. (10)

Long Wet Kilns

In a long wet-process kiln, the slurry introduced into the feed end first undergoes simultaneous heating and drying. The refractory lining is alternately heated by the gases when exposed and cooled by the slurry when immersed; thus, the lining serves to transfer heat as do the gases themselves. Large quantities of water must be evaporated; thus most wet kilns are equipped with chains suspended across the cross section of the kiln to maximize heat transfer from the gases to the slurry, or chain garlands that serve to recuperate heat and simultaneously convey the slurry. After most of the moisture has been evaporated, the nodules, which still contain combined water, move down the kiln and are gradually heated to about 550°C (1,022°F) where the calcination reactions commence. The calcined material further undergoes clinkering reactions. As the charge leaves the burning zone and begins to cool, clinker minerals crystallize from the melt, and the liquid phase solidifies. The granular clinker material drops into the clinker cooler for further cooling by air. (7)

Wet kilns typically represent an older cement technology with smaller capacity kilns. In the United States wet cement kiln capacities range from 77,000 to 1,179,000 metric tons/year with an average of 307,000 metric tons/year. (6)

Dry Process Kilns

The dry process utilizes a dry kiln feed rather than a slurry. Early dry process kilns were short, and the substantial quantities of waste heat in the exit gases from such kilns were frequently used in boilers to generate electric power, which often satisfied all electrical needs of the plant. In one modification, the kiln has been lengthened to nearly the length of wet-process kilns and chains were added. The chains serve almost exclusively a heat exchange function. Refractory heat-recuperative devices, such as crosses, lifters, and trefoils, have also been installed. So equipped, the long dry kiln is capable of better energy efficiency than wet kilns. Other than the need for evaporation of water, its operation is similar to that of a wet kiln. To improve the energy efficiency of the dry process, variations such as suspension preheaters and precalciners have been introduced as discussed in the next sections. (7)

Long dry process kilns are generally of a smaller capacity compared to long wet kilns. In the United States dry cement kiln capacities range from 50,000 to 590,000 metric tons/year with an average capacity of 265,000 metric tons/year. (6)

Dry Kilns With Preheaters

In dry kilns with suspension preheaters, the pulverized feed passes by gravity through a series of cyclones and riser ducts in a vertical arrangement, where it is separated and preheated several times, typically in a four-stage cyclone system. The partially (40 to 50 percent) calcined feed exits the preheater tower into the kiln at about 800 to 900°C (1,500 to 1,650°F). The kiln length required for completion of the cement formation is considerably shorter than that of conventional kilns, and heat exchange is very good. Suspension preheater kilns are very energy efficient compared to wet or long dry kilns. The intimate mixing of the hot gases and feed in the preheater riser ducts promotes condensation of alkalis and sulfur on the feed, which sometimes results in objectionable high alkali and sulfur contents in the clinker, or occasions buildups in the

preheater tower. To alleviate this problem, some of the kiln exit gases can bypass the preheater through a slipstream, or fewer cyclone stages can be used in the preheater with some sacrifice of efficiency.

Suspension preheater kilns represent a newer cement technology compared to the long dry kilns. They are also somewhat larger in production capacity than the conventional long rotary kilns. In the United States the preheater type kiln capacities range from 223,000 to 1,237,000 metric tons/year with an average capacity of 406,000 metric tons/year.

Dry Kilns With Precalciners

The success of preheater kiln systems, led to precalciner kiln systems. These units utilize a second burner to carry out calcination in a separate vessel attached to the preheater. The calciner utilizes preheated combustion air drawn from the clinker cooler or kiln exit gases and is equipped with a burner that typically burns about 60 percent of the total kiln fuel. Most often coal is used as a fuel in a calciner furnace; however, almost any fuel may be used including chipped tires. The raw material is calcined almost 95 percent, and the gases continue their upward movement through successive cyclone/riser duct preheater stages in the same manner as in an ordinary preheater. The precalciner system permits the use of smaller dimension kilns, since only actual clinkering is carried out in the rotary kiln. Energy efficiency is often even better than that of a preheater kiln, and the energy penalty for bypass of kiln exit gases is reduced since only about 40 percent of the fuel is being burned in the kiln. The burning process and the clinker cooling operations for the modern dry-process kilns are the same as for long wet kilns.

The precalciner technology is the most modern cement manufacturing technology and almost all of the newer cement plants are based on these designs. Precalciner kilns are also much larger in capacity than the conventional rotary kilns. The precalciner type kilns in the United States range from 449,000 to 1,580,000 metric tons/year with an average of 869,000 metric tons/year. Because of the new large precalciner plants replacing older and smaller plants, the overall average kiln capacity has been steadily increasing in the United States. It has increased from an average of 239,000 metric tons/year in 1980 to an average capacity of 393,000 metric tons/year in 1989.

Finish Grinding

The cooled clinker is conveyed to clinker storage. It is subsequently mixed with 4 to 6 percent gypsum and introduced directly into the finish mills. These are large, steel cylinders [2 to 5 m (7 to 16 ft) in diameter] containing a charge of steel balls, which rotate at about 15 to 20 rpm. Rarely, the desired size reduction may be accomplished in a roller mill, rather than in ball mills. Recently, the industry has also adopted the use of roller presses to precrush the clinker to smaller size prior to introduction to the finish mills. The roller press is more efficient than the crushing stage of the ball mill, and production capacities of finish grinding systems have been substantially increased and electrical energy requirements reduced by the incorporation of roller presses into finish circuits. The clinker and gypsum are ultimately ground to a fine, homogeneous powder. About 85 to 96 percent of the product is in particles less than 44 μm in diameter. This grinding may be accomplished by two different mill systems. In open-circuit milling, the material passes directly through the mill without any separation. A wide particle size distribution range is usually obtained with substantial amounts of very fine and rather coarse particles. Open circuit grinding is, however, rarely practiced in U.S. cement plants. In closed-circuit grinding, the mill product is carried to a cyclonic air separator in which the coarse particles are rejected from the product and returned to the mill for further grinding. (7)

Quality Control

Beginning at the quarry operation, quality of the end product is maintained by adjustments of composition, burning conditions, and finish grinding. Control checks are made for fineness of materials, chemical composition, and uniformity. Clinker burning is often monitored by the liter weight test (which involves weighing a portion of sized clinker), a free lime test, or may be checked by microscopic evaluation of the crystalline structure of the clinker compounds. Samples may be analyzed by wet chemistry, X-ray fluorescence, atomic absorption, or flame photometry. Standard cement samples are available from the National Institute of Standards and Technology. Fineness of the cement is most commonly measured by the air permeability method. Finally, standardized performance tests are conducted on the finished cement. (7)

2.1.3 Thermal Characteristics

Figure 2-1 provides a detailed look at the material and gas temperatures inside cement kilns. The concepts of high-grade heat and low-grade heat are well discussed by Weber. (11) Weber states, “The boundary between the main and the subsidiary thermal system is assumed always to correspond to a material temperature of 550°C, since decarbonation in the rotary kiln in general already begins at this temperature. A certain amount of heat whose temperature is below the gas temperature at the commencement of decarbonation will always be left over from the calcining zone. This heat is ‘lower-grade’ in the sense that, because of the low temperature, it cannot be further used for decarbonation or sintering, but only for preheating and drying.”

In turn, Figure 2-2 provides a graphical look at the relationship between temperatures in the cement manufacturing process and the chemistry of cement clinker formation. Except for the process of drying the raw material slurry in wet kilns these profiles are essentially the same for both wet and dry process cement kilns. The only substantive difference is that the difference between the gas and material temperature in a preheater tower is less than in the back end of a wet kiln because of the more efficient heat transfer in the cyclones.

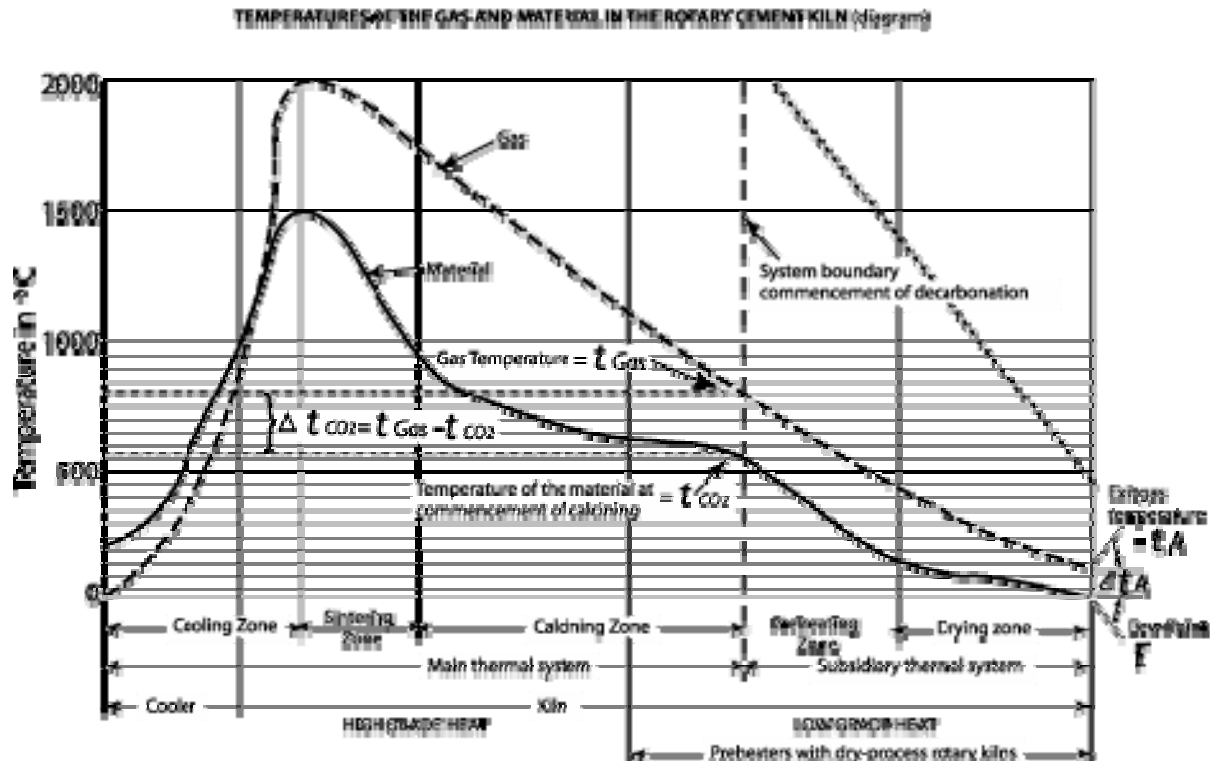


Figure 2-1. Temperature of the Gas and Material in the Rotary Cement Kiln 1

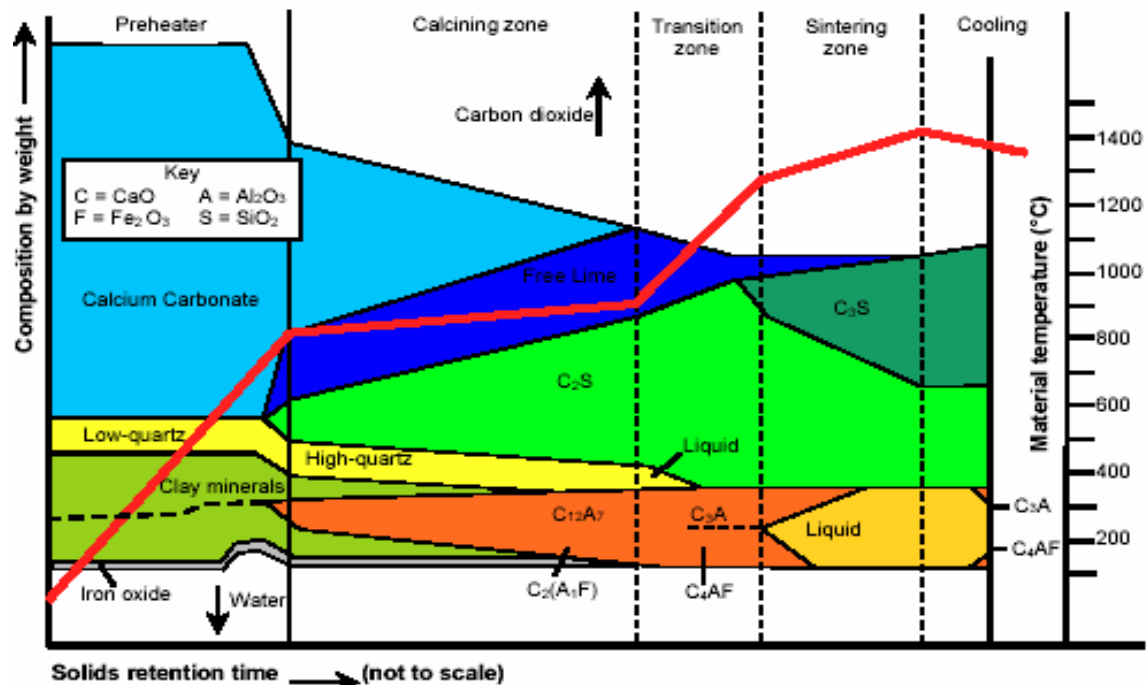


Figure 2-2. The Relationship Between Process Temperatures and the Chemistry of Cement Clinker Formation

2.1.4 Process Variables

The formation of clinker of suitable quality for manufacture of Portland cement depends on the characteristics of feed materials and the temperature profile of the pyroprocessing step.

The most critical process variables are:

- Feed composition;
- Feed particle size;
- Feed moisture concentration;
- Feed mass flow rate;
- System heat losses; and
- Ambient air infiltration.

More than 30 raw materials (primarily calcium carbonate, aluminosilicates, silica and iron oxide) are known to be used in Portland cement manufacturing. (12) These materials are ground and mixed to create a feed that has the appropriate chemical and physical properties to produce clinker with the desired properties. Uniform feed composition and size ensure consistent quality and characteristics of the clinker produced.

Higher moisture contents require more heat input to maintain proper temperature profile in the kiln. Cement raw materials are received with an initial moisture content varying from one to more than 50 percent. In dry kilns, the moisture content is usually reduced to less than one percent before or during the grinding process (e.g., using drum dryers, air separators, or supplying supplemental heat to the raw mill). In the wet process, water is added to the raw mill during the grinding of the raw materials, thereby producing a slurry of approximately 65 percent solids. (12)

3.0 NO_x FORMATION IN CEMENT KILNS

This section of the report is taken from the EPA 2000 Report and is included, with minor editing by the ERG Team. This information is included to provide the Texas environmental communities with the comprehensive background information necessary to understand the parameters that dictate NO_x control options at cement kilns.

3.1 Overview of NO_x Formation Mechanisms

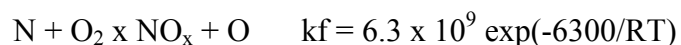
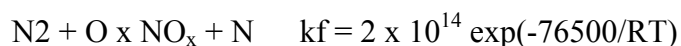
In cement manufacturing, conditions favorable for formation of nitrogen oxides (NO_x) are reached routinely because of the high process temperatures involved. Essentially, all of the NO_x emissions associated with cement manufacturing are generated in the cement kilns. Although, there are other heating operations in a cement plant, such as drying of raw feed or coal, often the heat from the kiln exhaust gases is used for these operations making their contribution to NO_x emissions negligible. In cement kilns, NO_x emissions are formed during fuel combustion by two primary mechanisms:

- Oxidation of the molecular nitrogen present in the combustion air which is termed thermal NO_x formation; and
- Oxidation of the nitrogen compounds present in the fuel, which is termed fuel NO_x formation.

Sometimes the raw material feed to the kiln may also contain nitrogen compounds, which may lead to feed NO_x formation similar to fuel NO_x formation. Because of the high temperatures involved in the burning or clinker formation step, the thermal NO_x formation provides the dominant mechanism for NO_x formation in cement manufacturing. The term NO_x includes both NO and NO₂ species, although NO₂ normally accounts for less than 10 percent of the NO_x emissions from a cement kiln exhaust stack. (13) The concentration and emission of NO_x are, however, typically expressed in equivalent NO₂ form.

3.1.1 Thermal NO_x Formation

Thermal NO_x is formed by the homogeneous reaction of oxygen and nitrogen in the gas phase at high temperatures. In the overall reaction mechanism proposed by Zeldovich, (14) the two important steps in NO_x formation are given as:



where k_f are the rate constants for the reactions shown. The high activation energy of reaction (4-1), 76.5 kcal/mol, means that this reaction is the most temperature sensitive. An equilibrium reaction of NO_x with O₂ further results in NO₂ formation.

The equilibrium concentrations of NO_x and NO₂ formed thus depend strongly upon the gas-phase temperature as well as the concentration of O₂ and N₂ in the gas phase. Table 3-1 shows the equilibrium concentrations of NO and NO₂ for two conditions. (15) First, the equilibrium concentrations of NO_x and NO₂ for N₂ and O₂ concentrations found in ambient air are shown. Secondly, Table 3-1 also shows the NO_x and NO₂ concentrations at flue gas conditions where the O₂ and N₂ concentrations are defined for this table as 3.3 percent O₂ and 76 percent N₂. The equilibrium NO_x concentrations for the flue gas conditions are lower than those for ambient conditions due to the lower O₂ concentration. The excess air used during fuel combustion can substantially affect NO_x formation by determining the amount of oxygen available for NO_x reaction. The cement kiln burning zones usually have about 5 to 10 percent excess air while higher excess air levels are not uncommon. Figure 3-1 shows the theoretical equilibrium concentrations of NO in the flue gas for different excess air levels. (13) As can be seen from this figure, over 1000 ppm of NO may possibly be formed at the typical kiln solids temperatures of 1430 to 1480°C (2600 to 2700°F) as the corresponding gas-phase temperatures are on the order of 1650°C (3000°F).

Table 3-1. Calculated Equilibrium Concentrations (In PPM) Of NO_x and NO_x In Air and Flue Gas (15)

Temperature		Air		Flue Gas	
K	°F	NO	NO ₂	NO	NO ₂
300	80	3.4 (10) ⁻¹⁰	2.1 (10) ⁻⁴	1.1 (10) ⁻¹⁰	3.3(10) ⁻³
800	980	2.3	0.7	0.8	0.1
1440	2060	800	5.6	250	0.9

Fuel combustion in the kiln burning zone is the primary source of thermal NO_x formation in cement kilns due to temperatures well above 1,400°C (2,550°F). In contrast, the fuel combustion temperature in a precalciner or in a kiln riser duct is well below 1,200°C (2,200°F), suppressing thermal NO_x formation. (16) Mainly fuel and feed NO_x may be formed in the secondary firing zone of preheater and precalciner kiln systems. Along with the combustion temperature, the gas-phase residence time and the available oxygen concentration in the high temperature kiln burning zone are important parameters. Longer residence times at the high temperatures will allow the NO to be formed in the equilibrium quantities. Greater amounts of oxygen in the combustion zone will of course lead to greater amounts of NO formation. Once formed, the decomposition of NO at lower temperatures, although thermodynamically favorable, is kinetically limited. Thus, strategies to reduce NO_x emissions need to be based upon reducing formation of NO_x, which may be achieved by reducing combustion temperature, oxygen concentration in the high temperature combustion zone, and the gas residence time at high temperatures.

3.1.2 Fuel NO_x Formation

Fuel NO_x is formed by the conversion of nitrogen present in the fuel used. A recent survey of the cement industry by Portland Cement Association (PCA) indicates that almost 82 percent of the energy requirement of the cement industry is provided by coal. (17) Natural gas contributed about 3 percent of the energy demand, oil about one percent, and other fuels such as waste solvents provided about 14 percent of the energy. Both oil and natural gas have relatively low fuel bound nitrogen content, whereas coal may contain one to three percent of nitrogen by weight depending upon the source of coal. Waste-derived fuels (WDF) such as scrap tires, used motor oils, surplus printing inks, dry-cleaning solvents, paint thinners, sludge from the petroleum industry, agricultural wastes such as almond shells, and even municipal biosolids (dewatered

sewage sludge) are finding an increasing application in the cement kilns. (18) The nitrogen content in these fuels may be significant depending on the chemicals included in the waste mix being burned.

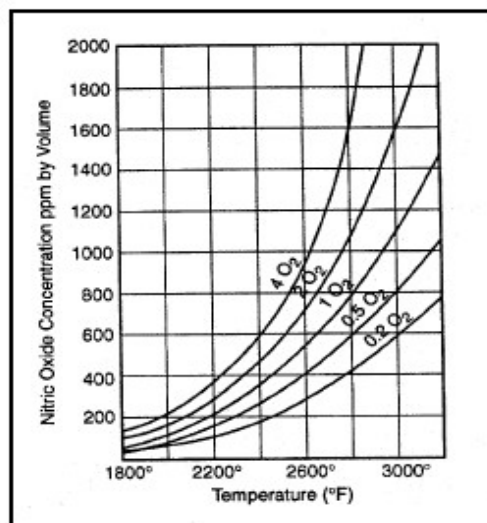


Figure 4-1. Theoretical equilibrium concentrations of NO in gas from combustions sustained in air.¹

Figure 3-1. Theoretical Equilibrium Concentrations of NO_x

The maximum possible fuel NO_x formation may be estimated from the fuel nitrogen content by assuming 100 percent nitrogen conversion. The typical heat requirement for a wet process is estimated to be about 6 million Btu for a ton of clinker and the corresponding requirement for a dry process is estimated to be about 4.5 million Btu for a ton of clinker. Assuming an average heat requirement of 5.3 million Btu for a ton of clinker, and a coal heating value of 12,000 Btu/lb, about 442 lb. of coal will be required per ton of clinker produced. With a nitrogen content of one percent by weight, approximately 9.5 lb. of NO (14.5 lb. expressed as NO₂) would be produced per ton of clinker with 100 percent nitrogen conversion. Thus, even with only 10 percent conversion of coal nitrogen to NO_x, 1.5 lb. of fuel NO_x (expressed as NO₂) may be formed per ton of clinker when coal is used as a primary fuel.

The amount of fuel NO_x formed is difficult to identify separately from thermal NO_x as measurements indicate the overall NO_x formed. In general, however, thermal NO_x is assumed to be the dominant mechanism in cement kilns. (19) Typically, gas burners produce more intense and hot flames compared to the less intense "lazy" flames produced by coal burners. Thus, gas-fired kilns may be expected to produce greater thermal NO_x as compared to coal-fired kilns.

Coal, on the other hand, contains much greater amounts of fuel-bound nitrogen than natural gas, which has almost no fuel-bound nitrogen. The coal-fired kilns may thus be expected to produce more fuel NO_x than gas-fired kilns. A study of gas- and coal-fired kilns, however, clearly indicated that gas-fired, dry-process kilns typically produce almost three times more NO_x than the coal-fired, dry-process kilns. (19) This fact indicates the dominance of thermal NO in overall NO formation.

3.1.3 Feed NO_x Formation

Similar to coal, the raw materials used in cement production may contain a significant amount of nitrogen. In most cases, limestone is the major raw material, with the remainder of the raw mix being composed of clays, shales, sandstones, sands, and iron ores. Fly ash from coal-fired power plants is used as a raw material and may contain substantial amounts of nitrogen compounds, since it is usually derived from coal. Most of these raw material components are sedimentary minerals and they may contain small amounts of chemically bound nitrogen, presumably of organic origin. Various kiln feeds contain appreciable amounts of nitrogen, ranging from about 20 ppm up to as much as 1,000 ppm (as N). (20) The higher values (>100 ppm) are generally associated with minerals displaying noticeable kerogen contents. Since 100 ppm N in a kiln feed is equivalent to about one lb. NO_x per ton of clinker (if it all converted), NO_x emissions from the kiln feed may represent a major source of NO_x from cement kilns. Nevertheless, it is probably less important than thermal NO_x and fuel NO_x in most cases.

The same study indicated that conversion of feed nitrogen to NO_x occurs mainly in the 300 to 800°C (570 to 1,470°F) temperature range and depends upon the feed heating rate. (20) Rapid heating rates (~1,000°C flash heating) of the kiln feed mixtures were found to give much lower conversion efficiencies, whereas slow heating rates of kiln feed mixtures (~60°C/min) gave fairly high conversion of about 50 percent of bound nitrogen to NO_x. These results were explained by assuming that the organic nitrogen must vaporize from the sample prior to oxidation if high conversion efficiencies to NO_x are to be achieved. If heating rates are rapid, "cracking" of these volatile compounds may occur in situ, and this may result in conversion of the bound nitrogen directly to N₂ before it comes into contact with gaseous oxygen, thus reducing the fraction converted to NO_x. Such a hypothesis is also consistent with the observation

that, during coal combustion, the involatile or "char" nitrogen is converted to NO_x much less efficiently than the volatile nitrogen. (21)

3.1.4 Factors Affecting NO_x Emissions in Cement Manufacturing

There are four primary types of cement kilns used in the industry: wet kilns, long dry kilns, kilns with a preheater, and kilns with a preheater/precalciner. The wet and long dry kilns and some preheater kilns will have only one fuel combustion zone, whereas the newer preheater and precalciner kiln designs have two or three fuel combustion zones: kiln burning zone, riser duct and precalciner. Because the typical temperatures present in the combustion zones are different, the factors affecting NO_x formation are also somewhat different in different kiln types and are discussed in the following sections. In addition to the specific NO_x formation mechanisms, the energy efficiency of the cement-making process is also important as it determines the amount of heat input needed to produce a unit quantity of cement. A high thermal efficiency would lead to less consumption of heat and fuel, and would generally produce lower NO_x emissions.

NO_x Formation in the Kiln Burning Zone

In the kiln burning zone, thermal NO_x provides the primary mechanism for NO_x formation. Thermal NO_x formation depends upon the combustion zone temperature, the gasphase residence time and the oxygen concentration in the high temperature combustion zone. The flame temperature strongly depends upon the type of fuel burned. The temperature and intensity are generally greater for gas burners than coal burners. The oxygen concentration in the combustion zone depends upon the overall excess air used and on the source and proportion of primary and secondary combustion air. Less primary air may produce an initial high-temperature, fuel-rich combustion zone followed by a low-temperature fuel-lean combustion zone. Such a combination is likely to reduce NO_x formation.

The firing system used in the kiln affects the proportion of primary and secondary combustion air. Direct firing systems introduce a large proportion of combustion air with the fuel being burned. This produces two conflicting effects for NO_x emissions: higher oxygen

concentration or fuel lean combustion and lower gas temperature. Indirect firing systems on the other hand use only a small portion of combustion air to convey fuel and thus use less primary air. In general, direct fired systems may be expected to produce greater NO_x emissions compared to indirect fired systems. The flame shape and the theoretical flame temperature are important factors in thermal NO_x formation as these factors determine the hottest points in the flame. A long "lazy" flame will produce less NO than a short intense flame.

The flame shape depends on the fuel being burned as well as the proportion of air. For the same amount of primary air, gas burning may be expected to produce a shorter and more intense flame than coal burning. The lower the secondary air temperature and the greater the dust content in the secondary air, the lower the NO_x formation in the kiln burning zone. A large amount of water in the primary air (from a direct firing coal mill) and injection of cement kiln dust (CKD) in the burning zone (insufflation) may also reduce NO_x formation. With increasing excess air percentage, the NO_x formation in the kiln will increase, but only up to a certain point as an increasing excess air rate will reduce the secondary air temperature and, consequently, the flame temperature.

Process conditions that can affect NO_x emissions substantially are: temperature stability, stability of raw mix feed rate, burnability of raw mix, and alkali and sulfur control. Temperature stability is important to maintain the quality of clinker and is achieved by stable-flame conditions and energy efficiency. Clinker formation reactions require temperatures of 2,650 to 2,800°F (1,450 to 1,540°C) and an oxidizing environment. Sometimes natural gas or liquid waste derived fuel is used to control flame conditions and improve clinker quality. The excess air used during combustion has a substantial influence on NO_x emissions. Oxygen levels of 4 to 5 percent in kiln exhaust gases would correspond to high NO_x emissions, whereas oxygen levels of only 0.5 to 1.5 percent would mean lower NO_x emissions. Thus, NO_x emissions in a kiln may depend upon the care exercised by the operator in minimizing excess oxygen needed to maintain the quality of the clinker produced. All but one of the clinker formation reactions are exothermic and represent a dynamic process that requires constant operator adjustments which can vary NO_x formation.

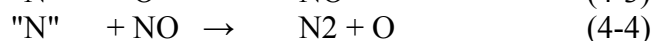
The heating value of the fuel burned may also affect NO_x emissions. High heating value fuels, such as petroleum coke may require less combustion air and produce less NO_x per ton of clinker.

Different raw material compositions require different burning conditions to maintain the quality of clinker produced. Thus, similar types of kilns with different feed materials may produce different levels of NO_x emissions. The alkali content of finished cement needs to be below a certain acceptable level. Low alkali requirements may require higher kiln temperatures and longer residence times at high temperatures to volatilize the alkali present in the molten clinker. Raw materials with greater alkali content may need to be burned longer at higher temperatures to meet alkali requirements and thus may produce greater NO_x emissions. Increased volatilization of alkali results in increased alkali emissions in kiln exhaust gases. To control alkali emissions, a part of the kiln exhaust gases may be bypassed around a downstream unit, e.g., a precalciner. The bypassed gases are quenched to remove alkali and sent through a particulate matter collector. This alkali-rich particulate matter is removed from the process and disposed. The bypass of kiln exhaust gases typically involves a fuel penalty, e.g., about 20,000 Btu/tonne clinker for every one percent gas bypass. The additional heat requirement will contribute to increased NO_x emissions.

Wet kilns require about 33 percent more thermal energy than a dry kiln. This means a greater volume of exhaust gas from a wet kiln for the same production. On the other hand, the greater amount of combustion air will also mean a somewhat lower secondary air temperature. Based on these contradicting factors, one might expect the NO_x emissions from a wet process kiln to be similar to the dry and preheater kilns without riser duct firing.

NO_x Formation in Secondary Firing

In the secondary firing region of precalcining kilns, where temperatures range from 820 to 1100°C (1500 to 2000°F), the following reactions may take place:



where "N" means nitrogen originating from nitrogen compounds in the fuel. (13) Reaction (4-3) shows that NO formation in the secondary firing zone will depend upon the nitrogen content in the fuel and the oxygen level in the firing zone. Reaction (4-4) indicates that, if there is already NO present in the gas introduced into the secondary firing zone, a reduction of this NO may occur with the fuel nitrogen compounds acting as reducing agents. Accordingly, the net formation of NO in the secondary firing zone will also depend upon the initial NO concentration in the combustion gas. Finally, measurements have shown that the volatile content in the solid fuel and the temperature in the secondary firing zone also influence the NO formation in the secondary firing zone. (22) With increased volatile content in the fuel, the ratio of fuel nitrogen conversion into NO seems to decrease and, as the reaction rate of reaction (4-4) increases more rapidly with the temperature than that of reaction (4-3), an increase in the temperature of the secondary firing region may reduce-the net NO formation. (13)

3.1.5 Suspension Preheater (SP) Kilns with Riser Duct Firing.

In many SP kiln systems 10 to 20 percent of the fuel is fired into the riser duct. The preheater systems are more energy efficient compared to long dry kilns. The increased energy efficiency and the reduction in the amount of fuel burned at the higher clinker burning temperature may be expected to reduce the NO_x emissions from preheater kilns when compared with the long dry and wet kilns. Measurements at several riser-duct fired kiln systems indicate that firing coarse fuel (e.g., tires) into the kiln riser duct will reduce NO_x emissions from the kiln systems. (23) This may be explained by the fact that a large part of the fuel falls directly down into the kiln charge, creating a reducing atmosphere in the kiln back-end where NO_x from the burning zone is reduced.

Conversely, when firing finely ground fuel into the kiln riser duct, the NO_x content in the exhaust gas may increase on passing through the riser duct. As the NO_x emissions from the kiln may also increase slightly due to an increased excess air rate, the total NO_x emissions from the kiln system may increase when starting up riser duct firing with finely ground fuel. (13)

3.1.6 Precalcining Kiln Systems.

In precalcining kiln systems with a tertiary air duct, firing into the rotary kiln typically accounts for only 40 to 50 percent of the total heat consumption and the specific amount of combustion gases from the kiln burning zone is reduced proportionally. Precalciner kilns also typically require the least amount of energy per unit amount of clinker produced. The lower energy requirement and the substantial reduction in the proportion of the fuel burned at clinker burning temperatures may be expected to reduce the NO_x emissions from the precalciner kilns as compared to the preheater kilns. On the other hand, the NO_x concentration (in ppm) in the kiln gas may be considerably higher than in preheater kilns. This is probably due to the shorter material and longer gas retention times in the precalciner kiln burning zone combined with a very high secondary air temperature. (13)

When examining the contribution from the calciner firing to the emission of NO_x , two basically different types of precalcining kiln systems need to be considered:

- The in-line (ILC) type in which the kiln gas passes through the firing region of the precalciner; and
- The separate line (SLC) type in which the kiln exhaust gas bypasses the firing region of the precalciner.

ILC systems: In these systems, the fuel combustion in the calciner takes place in a mixture of the kiln exhaust gas and hot air from the cooler (tertiary air). Some of the nitrogen in the fuel reacts with NO from the kiln exhaust gas while another part reacts with oxygen to form NO. The result may be a net increase or a net reduction of NO in the calciner.

SLC systems: In these systems, the fuel combustion in the calciner takes place in pure hot air. In the case of oil firing, NO production in the calciner is negligible; but when using fuels containing fuel-bound nitrogen, up to 50 percent of the nitrogen compounds in the fuel may be converted into NO_x . The specific NO_x production in an SLC calciner may be as high as 4 lb. NO_x per ton of clinker as measured in a calciner fired with petroleum coke which has a high nitrogen content and low volatile content. (13) The NO_x in the calciner exhaust gas is added to the NO_x in the gas from the rotary kiln which leaves this type of kiln system without being

reduced. When fired with solid fuels, SLC systems may therefore be expected to generate somewhat higher NO_x emissions than the ILC systems. (13) We should note, however, that some of the oxygen for combustion of the fuel in ILC systems passes through the burning zone, so the NO generated there may be higher (or lower due to lower temperatures) than for SLC systems.

3.1.7 Energy Efficiency of the Cement-Making Process

Since NO_x formation is directly related to fuel combustion, any reduction in the amount of fuel burned per unit amount of clinker produced should reduce NO_x emissions per unit clinker. Attempts to improve energy efficiency of the process by avoiding excessive clinker burning and utilizing waste heat effectively for preheating combustion air, coal, and raw mix is likely to reduce NO_x emissions. Improving heat transfer between hot gases and solid materials, e.g., by chain systems, will improve energy efficiency. The newer preheater and precalciner kiln designs provide very efficient preheating and precalcining of the raw mix with intimate gas-solids contact in cyclone towers. New cement kiln installations or renovations of older kilns thus predominantly involve precalciner designs for their energy efficiency. The inherent energy efficiency of these kiln designs is likely to produce lower NO_x emissions per unit amount of clinker as compared to the wet or long dry kilns.

4.0 OVERVIEW OF POTENTIALLY APPLICABLE CONTROL TECHNIQUES AND TECHNOLOGIES

Nitrogen oxides are formed by the oxidation of nitrogen during the fuel combustion process. The formation of thermal NO_x is a function of the flame temperature, flame turbulence, the amount of nitrogen and oxygen available for the thermal reaction, and the gas phase residence time at high temperature. To reduce the amount of thermal NO_x formed, one or more of these variables needs to be minimized. The formation of fuel and feed NO_x is not as well understood as the thermal NO_x formation. In general, however, the greater the concentration of nitrogen in the fuel and feed, the greater the fuel NO_x emissions. Therefore, reducing the amount of fuel and feed-bound nitrogen should reduce the contribution of the fuel and feed NO_x.

The typical NO_x emissions from a cement plant depend upon the type of the cement kiln as shown in Table 4-1. For any given type of kiln, the amount of NO_x formed is directly related to the amount of energy consumed in the cement-making process. Thus, measures that improve the energy efficiency of this process should reduce NO_x emissions in terms of lb. of NO_x/tonne clinker. With the rising costs of energy and the very competitive cement market, greater attention is being paid to increasing overall energy efficiency, such as through reduction of overburning of clinker and improvement in gas-solids heat transfer. Continuous emissions monitoring of CO, NO_x, and O₂ provide an indication of kiln conditions and also provide inputs for process control. Newer cement kiln designs are generally based on preheater/precalcliner systems which provide very efficient gas-solids contact and greater energy efficiency. NO_x control approaches are evaluated below under four categories:

- High Temperature Emissions Controls;
- Combustion Optimization;
- Low Temperature Oxidation Emissions Controls; and
- Process Modifications.

This section of the report uses the EPA 2000 Report as the baseline for evaluating current control options for Ellis County kilns. The combustion and process optimization sections are included, with editing, from this report and describe the essential controls that have been considered and largely installed under the requirements of 30 TAC Chapter 117. Additions to sections for process modifications to improve energy efficiency through calciner modifications

and wet to dry conversions is discussed as site-specific options where applicable for Ellis County kilns. The section on oxidation controls is entirely new and was not considered in EPA 2000. The sections on SCR and SNCR consider EPA 2000 background information, but are written to reflect current status of these technologies and site-specific application to the Ellis County kilns. For the purposes of this report, *available* essentially means that the technology is commercially available and in use on similar types of cement kilns. *Transferable* means that the technology is commercially available and in use on similar process equipment and could reasonably be expected to work on the specified type of cement kiln. *Innovative* describes technologies that have not been successfully applied to a type of cement kiln, but in the judgment of the ERG Team could be expected to work on the type of cement kiln if correctly optimized through experimental application.

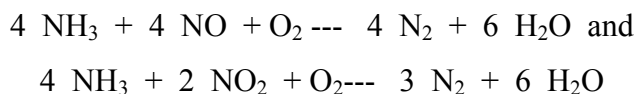
When discussing the transfer of technologies, comparisons are made between cement kilns, coal-fired utility boilers and refinery fluidized catalytic cracking units (FCCUs). While the emissions from these units vary widely, they are all capable of emitting thousands of tons of NO_x and SO₂ and typically use electrostatic precipitators (ESPs) to control particulate emissions that would also be thousands of tons per year prior to control. For the purposes of this discussion, a modern cement kiln producing one million tons per year of clinker would be roughly comparable to a coal-fired utility boiler of approximately 200 megawatts generating capacity and an FCCU of approximately 80,000 barrels per day. All of these units would have a typical air flow of approximately 300,000 cubic feet per minute. For comparison with the Ellis County kilns, a typical refinery of comparable air flow rate would tend to produce less NO_x and a utility boiler would typically produce more NO_x. The amount of SO₂ from these units would vary widely due to site specific operating conditions including fuels and feeds materials. The impact of SO₂ and particulate matter concentrations on the operation of SCR is discussed in depth below under Section 4.1.2. Other constituent pollutants in the gas stream are not considered to interfere with LoToxTM operation. Both SCR and LoToxTM have been demonstrated in units of comparable air flow to the Ellis County kilns.

4.1 High Temperature Emissions Controls

4.1.1 Selective Catalytic Reduction (SCR)

SCR is a process that uses ammonia in the presence of a catalyst to selectively reduce NO_x emissions from exhaust gases. This technology is widely used for NO_x abatement in other industries, such as coal-fired power stations and waste incinerators. The SCR process has been used extensively throughout the world to achieve a 90 percent reduction in NO_x emissions from fossil fuel fired boilers. In the United States SCR technology has successfully been used for gas turbines, internal combustion engines, and utility boilers.

In SCR, anhydrous ammonia, usually diluted with air or steam, or urea, is injected through a grid system into hot flue gases that are then passed through a catalyst bed to carry out NO_x reduction reactions. The two principal reactions are:



The first reaction represents the predominant reaction since 90 to 95 percent of NO_x emissions in the flue gas are in the form of NO. A number of materials have been used for catalysts. Titanium dioxide (TiO₂) and vanadium pentoxide (V₂O₅) mixtures are most commonly used as catalysts due to their resistance to SO_x poisoning. Zeolite-based catalyst materials have also been developed capable of operating at higher temperatures than conventional metal-based catalysts. The catalyst is typically supported on ceramic materials, e.g., alumina in a honeycomb monolithic form. The active ingredients of the base metal (titania-vanadia) and zeolite catalysts often make up the bulk of the substrate material. The catalyst shape and reactor design vary depending upon the manufacturer.

The optimum temperature for the catalytic reactions depends upon the specific catalyst used and is usually in the range between 300 to 450°C (570 to 840°F). Without pre-heater and/or pre-calciner systems this temperature range may be higher than typical cement kiln flue gas temperatures, especially in plants using heat recovery systems or baghouses for particulate

collection. But it may be possible to reheat the exhaust using heat recovery systems. Of particular relevance, then, is the ability to use SCR at wet kilns.

Ammonia is typically injected to produce a NH_3 : NO_x molar ratio of 1.05-1.1:1 to achieve NO_x conversion of 80 to 90 percent with an ammonia "slip" of about 10 ppm of unreacted ammonia in the gases leaving the reactor. The NO_x destruction efficiency depends upon the temperature, NH_3 : NO_x molar ratio, and the flue gas residence time (or the space velocity) used in the catalyst bed. The SCR reactor system can be designed for a desired NO_x reduction using appropriate reagent ratio, catalyst bed volume, and operating conditions. In general, the catalysts may be fouled or deactivated by the particulates present in the flue gas. In the case of cement plants, the presence of alkalis and lime, as well as sulfur dioxide, in the exhaust gases is also of concern. Recent developments, however, have led to sulfur tolerant SCR catalysts. In addition, soot blowers may be used to prevent dust accumulation on SCR catalysts.

In the cement industry, basically two SCR systems are being considered: low dust exhaust gas and high dust exhaust gas treatment. Low dust exhaust gas systems require reheating of the exhaust gases after de-dusting, resulting in additional cost. High dust systems are considered preferable for technical and economical reasons.

SCR may only be available as an applicable technology for dry kilns with preheat, as is described later herein. There are currently no installations of SCR units in any United States cement plants, however, a full-scale unit has been operating in Germany for over three years with SCR. As set forth in greater detail below, selective catalytic reduction has been installed and successfully operated at this one cement plant in Germany and SCR is now commonly used to control NO_x emissions from coal-fired power plants. This technology achieves NO_x emission reductions in the range of 80 to 90 percent or higher.

The experience of the German cement plant may be sufficient to demonstrate that the concerns regarding catalyst poisoning and fouling have been addressed with the development of a special catalyst specifically designed for the cement industry. In a typical design of a dry kiln with preheat, the SCR system could be located downstream of the pre-heater cyclones, prior to

the roller mill. The process exhaust temperature at the outlet of the pre-heater cyclones would be approximately 320°C (608°F), which is ideal for a SCR system.

Potential Advantages of SCR

The potential advantages of SCR are as follows:

- **SCR can potentially provide a high degree of NO_x removal.** Presently, guarantee levels on SCR systems being provided in the power industry are in the 90% to 94% range. Even on difficult applications such as coal-fired power plants, which have very dusty flue gases, NO_x control efficiencies of 90%+ are being guaranteed by vendors and being achieved.
- **SCR is an add-on or end-of-pipe control technology.** For dry kilns with preheat, the SCR system would be located downstream of the cement kiln and pre-heater furnace and cyclones and hence it would not interfere with or affect the cement manufacturing process. This would be a big advantage over the Selective Non-Catalytic Reduction (SNCR) process, which must be carried out in process conditions.
- **SCR can use urea (CO(NH₂)₂) rather than ammonia as the reducing agent.** To use urea, a conversion system is required. In a typical conversion system, urea is mixed with water and then heated. The process converts the urea to gaseous ammonia, which is then injected into the flue gas. This system is commonly used where there are safety concerns arising from the transport and storage of ammonia.

SCR at Coal-Fired Power Plants

Prior to 2001, there were approximately 12 coal-fired power plants in the United States utilizing SCR for NO_x control. According to the Electric Power Research Institute, there are now about 200 coal-fired power plants (totaling 100,000 megawatts of generating capacity) on-line utilizing SCR control. Most of the plants on which SCR has been installed are designed for, and have been achieving, 80% to 90% control of NO_x.

One possible problem mentioned with respect to utilizing SCR in cement plants is the technical feasibility of installing SCR in an environment where dust from the kiln could poison the catalyst, making SCR technically infeasible. On coal-fired power plants, the SCR catalyst is usually installed downstream of the boiler (between the economizer and the air pre-heater) prior

to the particulate control device. As a result, the catalyst is subject to the full dust loading from coal combustion, just as it would be at a cement plant. Typically, coal contains 6% to 20% ash on a dry basis. The high dust, high temperature characteristics of coal plant emissions thus are similar to those of cement kiln exhaust gases. The experience of the power industry with SCR on coal-fired power plants suggests that the catalyst poisoning and fouling concerns may be manageable.

SCR Experience in Cement Kilns

Differences in the nature of the cement kiln and coal fired power plant processes, the chemical composition of the ash and other factors mean that the success of SCR in controlling NO_x emissions from coal-fired power plants is not definitive evidence that the technology can be successfully applied at a cement plant. Among other things, dust from cement kilns is high in calcium, relative to coal dust, and calcium deactivates most conventional SCR catalysts. Also, the grain loading of cement kilns is likely to be different from that of coal-fired power plants, placing different stresses on the control device. As discussed in greater detail below, however, the recent successful use of SCR at a German cement plant demonstrates that these and other issues may have been resolved and that SCR is, under certain conditions, a technically feasible alternative for significantly reducing NO_x emissions from cement kilns.

The Solnhofen Portland-Zementwerke AG cement plant in southern Germany located between Munich and Nuremburg has been in successful operation with SCR since 2001. Lurgi, the engineering company who supplied the SCR system, addressed the problem of catalyst deactivation discussed above (caused by the high calcium content of cement plant ash) by developing a catalyst specifically for the cement industry. The catalyst can use ammonia or urea as a reagent. If urea is used, a conversion unit is used to convert the urea to ammonia prior to injection in the SCR system. These units, which are quite common, avoid the need to store ammonia on-site for use as a reagent.

As of the beginning of 2005, there was no evidence of catalyst poisoning or deactivation. The problem of fouling from the heavy dust loading has proven to be quite manageable with regular maintenance (i.e., cleaning of the catalyst with a vacuum cleaning system).

The SCR system is achieving NO_x emission reductions far in excess of those achievable using SNCR. Prior to installation of SCR, the Solnhofen plant, with SNCR, was achieving NO_x emissions of 700 to 800 mg/ Nm³ (equivalent to 2.8 to 3.2 lb./tonne clinker). With SCR, the plant has been achieving approximately 200 mg of NO_x/Nm³ (0.8 lb./tonne clinker). Based on an uncontrolled NO_x emission rate of 1050 mg/Nm³ (4.2 lb./tonne clinker), the emission rate corresponds to a NO_x control efficiency of 80% for SCR compared with approximately 25-35% control efficiency for SNCR. It has been indicated, however, that the SCR system was capable of achieving a lower NO_x emission rate (they are not using all of their beds), but that they were operating at 200 mg/Nm³ since German law only required a NO_x emission limit of 500 mg/Nm³.(23a, 23b, 23c, 23d)



Figure 4-1.1 SCR on Preheater Tower at Solnhofen Zement, Germany

At approximately 500,000 tonnes per year of clinker, Solnhofen is smaller in capacity than the preheater/calcliner units in Ellis County and larger than the wet kilns. With an uncontrolled NO_x emission rate of approximately 4.2 lb./ton, Solnhofen has a slightly higher emissions rate than the Holcim units and slightly lower than the Ash Grove kilns. The emissions rate is much higher than TXI #5 and much lower than the TXI wet kilns.

Site Specific Application of SCR to Ellis County Cement Kilns

SCR offers the possibility of significant NO_x reduction at the plants in Ellis County. As an “add on” technology, which can achieve 90% or greater NO_x reduction, with demonstrated performance at hundreds of coal fired power plants, SCR is a viable technology that is available for both dry and wet kilns. The economics of SCR are greatly influenced by the temperature of the flue gas at the point of installation. For the three dry precalciner kilns in Ellis County, a location in process with suitable temperatures is assumed and this leads to lower overall costs and cost effectiveness. For the wet kilns, a location downstream from the electrostatic precipitators (ESPs) is selected for installation, and reheat of the process gas is required. This substantially increases the overall cost and decreases the cost effectiveness of SCR in comparison to the dry kiln applications.

The technology has been available at only one cement plant, the Solnhofen Portland – Zementwerke AG dry kiln plant in Southern Germany, now in its fourth year of operation with SCR. While there are, at this time, no operating units in the U.S., the German experience leads one to assess the possibility that SCR can make a significant impact on NO_x reduction in Ellis County. In fact, the Midwest Regional Planning Organization has recently concluded that SCR is a reasonably available technology for controlling NO_x at cement plants (23e), and the possibility exists, with reheat, to utilize SCR at wet, as well as dry, kilns.

Applicability of SCR to Cement Kilns and Areas of Concern

Before examining site-specific data, it is important to first examine the areas of concern with respect to SCR, many of which have been raised in the literature (23f, 23g, 23h, 23i). This is necessary to see whether the data from the coal fired plants and from the one cement plant, is

sufficient to attempt to make even qualified statements with respect to existing facilities, even though some analyses now suggest that the German data indicates that these problems will not exist for the cement industry in the U.S. (23g). These concerns are delineated and discussed here. They include: catalyst deactivation due to catalyst poisoning; catalyst plugging and fouling due to high dust loading and deposits; reduction in NO_x control efficiency due to high sulfur levels; temperature related factors leading to lower NO_x removal efficiencies; NO_x concentration variability and ammonia slip; and undesirable by-product formation in the SCR causing adverse affects on downstream equipment.

Catalytic Deactivation Due to Catalyst Poisoning

Poisoning occurs when the contaminants in the gas being treated react with the catalyst, resulting in catalyst deactivation. It has been argued that the SCR catalyst in a cement plant will be subject to poisoning, principally from sodium (Na), potassium (K), and arsenic trioxide (As_2O_3). Phosphorus, chromium and lead compounds can also poison an SCR catalyst, but since these are expected to be present in lower concentrations at cement kilns, they are of lesser concern. However, the typical concentration of sodium oxide (Na_2O) in the particulate matter (PM) of certain coal-fired plants is greater than double the concentrations of Na_2O in the PM of the average cement plant, and the maximum concentration of Na_2O can be significantly greater than the maximum expected concentration of Na_2O in the PM of the average cement plant. Similarly, the concentration of As_2O_3 in the flue gas of the typical coal fired plant is well above the concentration of As_2O_3 in the expected flue gas from the average cement plant. Regarding the availability of catalyst poisons, an additional argument deals with the solubility of Na and K in the fly ash and the form of the fly-ash particles.

It is argued that in cement pre-heater pre-calciner kilns, materials such as sodium and potassium compounds may be present in relatively elevated concentrations on the surfaces of particles in “water soluble” form that can contact the surface of the SCR catalyst bed and thereby provide an opportunity to poison the V_2O_5 “active ingredient” in the SCR bed. Conversely, it is argued, in coal-fired boilers, the sodium and potassium are, to a major extent, trapped within a glass-like fly-ash particle. It is widely known however that fly-ash particles from coal-fired boilers are in the form of tiny spheres (cenospheres) and that during the combustion of the coal,

the particles are actually liquid and the spheres are formed as tiny bubbles by evolved gases trying to escape. Boilers are designed to cool the molten particles to a solid state such that they can be easily removed from boiler tubes. However, depending on the temperature of the fly ash and its chemical composition, some of the fly ash will deposit in various sections of the boiler. The deposits that form at the back-end of the boiler (on the economizer and air heater) are called “low-temperature deposits”. Low temperature deposits are usually characterized by low pH (highly acidic); many contain hydrated salts, and for most bituminous coals are water-soluble. Therefore, coal-fired boilers have fly-ash deposits in the economizer section of the boiler that are water-soluble. However, deactivation has not been found to occur. In addition, SCR systems have been installed on oil-fired boilers despite the relatively higher levels of water-soluble alkaline metals found in the fly ash from such boilers.

Catalyst Plugging and Fouling Due To High Dust Loading and Depositing of “Sticky” Materials

Catalyst plugging and fouling involves the accumulation of dust that blocks access to the pores of the catalyst. It is argued that high dust loadings could plug or foul the SCR catalyst beds. However, the Solnhofen SCR system has operated at a dust loading of 80 g/Nm^3 , a relatively high dust loading. The level of NO_x removal shows that high dust loading can be managed to avoid catalyst plugging and fouling while maintaining high levels of control. Related to the plugging and fouling issues, it is argued that “sticky deposits” in the pre-heater exhaust gas could foul and plug the SCR catalyst. Specifically, certain cement kiln operations could be prone to producing sticky deposits at exactly the temperature ranges in which SCR systems operate. Sticky deposits are a widespread problem occurring throughout the world on cement kiln induced draft (I.D.) fans. In many plants it is an extremely hard, layered, brick-like build-up that is associated with impingement of particulate at high velocity against the rotating parts of the fan impeller.

While the presence of alkali in the cement kiln system is a factor in the build-up, the mechanical aspect (namely, impact velocity) is more critical to the formation of build-up. The recommendation for avoiding build-up is to select a fan that minimizes the gas/dust velocity at the inlet of the fan rotor. Alternatives include using double inlet fans or using larger diameter, lower RPM (revolutions per minute) fans. Sticky deposits or build-up developing on other parts

of the cement kiln system are not common. Thus, the sticky deposit problem appears to be related solely to the I.D. fan and is due to the high impact velocity of the dust particles mostly on the fan. This problem should not affect an SCR catalyst that is subject to comparatively low gas velocities in comparison to an I.D. fan.

For instance, gas velocities through an SCR system are typically less than 6.2 meters per second (1220 ft./min.), whereas peripheral gas speed at the kiln I.D. fan rotor inlet is approximately 15,000 ft./min. Possible problems relating to thermal sintering and catalyst erosion have been addressed by advances in catalyst technology and proper system design. The problem of thermal sintering has been avoided by the incorporation of tungsten in the catalyst formulation and also by providing a bypass around the SCR system so that the catalyst is not exposed to high temperature excursions. Hardening the leading edge of the catalyst and also arranging the catalyst bed so that the airflow is parallel to the catalyst channels have addressed catalyst erosion.

Reduction in NO_x Control Efficiency Due to High Sulfur Levels

In general, operational histories of SCR installations at coal fired plants and the one cement plant indicate that NO_x reductions are being achieved in a reliable manner. The reason that many of the older units are not achieving NO_x removals greater than 80% is that the plants were not designed to achieve such high removal efficiencies. Great advances in the application of SCR technology have taken place. Present day SCR systems are typically achieving NO_x reduction efficiencies of 90% or greater. It is argued that when only a low NO_x reduction is required, the catalyst manufacturer can use a catalyst with a lower vanadium oxide content which will reduce the oxidation of SO₂ to SO₃ and thereby avoid the potential for CaSO₄ masking. However, the Solnhofen SCR system is achieving a high degree of NO_x control.

It is argued that high SO₃ concentrations could lead to catalyst deactivation and other serious problems relating to SO₂ oxidation. A high SO₃ concentration (10 -20 ppmv) when coupled with the high calcium level in the cement kiln flue gas could purportedly cause deactivation of the SCR catalyst due to the masking effect of calcium sulfate (CaSO₄). In addition, any SO₃ that does not react with the calcium could react with any unused NH₃ to form

ammonium sulfate (AS) or ammonium bisulfate (ABS) that could cause fouling of downstream equipment. Sulfur in the raw mix can be in several forms, namely: calcium sulfate, magnesium sulfate, and sulfides such as pyrites or organically bound sulfur. Only the volatile sulfur compounds (namely: the sulfides and organically bound sulfur) are oxidized and released in the pre-heater as SO₂. With respect to these concerns, the success of SCR systems at a number of coal-fired boilers show that SCR systems can be designed for high calcium and high sulfur flue gases and the SCR catalyst suppliers have indicated that CaSO₄ formation does not pose a major concern, as they assert that the SO₃ generated in the process is captured by the large amount of free lime in the gas stream. SO₂ oxidation by the catalyst will then have no negative impact on the amount of SO₃ formed and subsequently captured. There is also concern regarding the possible formation of ammonium salts, which can form in SCR systems at temperatures below 580 to 590°F. However, this problem can be avoided by ensuring that the SCR inlet temperature is always 600F or greater.

Temperature Related Factors Leading to Lower NO_x Removal Efficiencies

Several temperature-related factors have been identified as important to successful operation of an SCR system. These are: (1) an acceptable normal operating temperature; (2) an even temperature distribution; and (3) avoiding temperature extremes (which may lead to catalyst deactivation or sintering). Low temperatures can lead to lower NO_x reduction efficiencies and/or higher catalyst activity (leading to possible SO₂ oxidation) and to possible ABS/AS formation in the catalyst pores. Concerns regarding a slightly lower than desirable inlet temperature, however, can be resolved by installing equipment to ensure a desired temperature of 600°F or greater going into the SCR system. Such control systems are commonly used on boiler air supply systems and economizer bypass ducts. Note that the SCR reactor should also have an automatically activated bypass duct around the SCR reactor, so that in the event of high temperature fluctuations (greater than approximately 800°F), automatically controlled dampers would send the hot flue gas to a reactor bypass duct, thus preventing any damage to the SCR catalyst. Therefore, temperature issues, whether involving normal operating temperatures or temperature fluctuations, should be correctable with simple process reconfigurations.

NO_x Concentration Variability and NH₃ Slip

It has been argued that unlike a coal-boiler SCR application, an SCR system applied to a cement kiln will be faced with highly variable inlet NO_x loadings and that elevated NH₃ slip levels are possible, which, coupled with possibly higher sulfur oxide levels, represent a serious risk. However, in an SCR system, the injected NH₃ is adsorbed onto the surface of the catalyst. Thus, there is a reservoir of unused NH₃ on the surface of the catalyst that is available to handle sudden peaks in inlet NO_x concentrations and thereby enable SCR systems to control fluctuating levels of NO_x. SCR systems do not have to overfeed ammonia to handle surges in inlet NO_x concentration and so tend to have very low NH₃ slip levels.

Coal-fired boilers have been operating SCR systems successfully for years despite considerable NO_x fluctuations in their flue gases. SCR suppliers typically guarantee a NH₃ slip of no more than 2 ppmv for any coal-fired boiler SCR application. In addition, the Solnhofen plant is a cement kiln with all of the inherent variability and has nevertheless been achieving a high degree of NO_x control with a low ammonia slip level. Data at Solnhofen indicates that the SCR inlet NO_x concentration varies considerably, from less than 1000 mg/Nm³ to 2030 mg/Nm³ while the outlet NO_x concentration varies from approximately 300 to 726 mg/Nm³, but maintains an average outlet NO_x concentration of less than 500 mg/Nm³. At these variable conditions, however, NH₃ slip has been maintained in the 1-2 ppmv range.

Undesirable Byproduct Formation in the SCR Causing Adverse Effects on Downstream Equipment

Concerns have been raised regarding the generation and release of SO₃ that could cause corrosion of downstream equipment, or that the SO₃ may react with unused NH₃ to form ammonium salts (ABS and AS), which could plug or corrode downstream equipment. In addition it is argued that ammonium salts could increase condensable particulate matter levels, making it difficult for a facility to meet its particulate matter emission limit. In SCR systems with SO₃, NH₃ and moisture present, ammonium salts will form at temperatures below 580-590°F. The best way to prevent their formation is to continuously control the SCR inlet temperature such that it is always 600°F or greater. Regarding the possible release of SO₃, catalyst manufacturers report that the SO₃ gas is totally captured by conversion to particulate

calcium sulfates and sulfites as it is contacted by free lime upstream, within, and downstream of the SCR catalyst. Thus, the formation of undesirable byproducts should be inherently controlled by the free lime in the system and can be further controlled by controlling the SCR inlet temperature.

General Conclusions

The experience of coal-fired power plants and the one cement plant with SCR offers the following lessons. First, the success of coal-fired power plants shows that catalyst deactivation from alkali poisoning is not expected to be a significant problem for cement kiln applications. Second, the success of SCR systems on a number of coal-fired boilers reveals that even when flue gases have significant levels of both calcium oxide (CaO) and sulfur dioxide (SO₂), the condition can be handled in SCR systems without the occurrence of pore masking from calcium sulfate (CaSO₄) formation. Third, the power plant experience shows that SCR systems can be designed to achieve at least 85% NO_x reduction despite extremely large gas flow rates with significant NO_x variability and relatively high particulate loadings. Last, the power plant experience shows that equipment can be designed and operated such that the flue gas entering the SCR catalyst will always be in the proper temperature range. For wet kiln applications, this can lead to a requirement for significant gas re-heat.

Site-Specific Analyses

The follow sub-sections are specific to TXI, Holcim, and Ash Grove. In what follows, the additional NO_x associated with gas re-heat, if required, has not been added, as the level of additional NO_x would be below 10 tons per year and 85% of that would be removed.

SCR at the TXI Kilns

To consider SCR at the TXI facilities, one must perform separate analyses for Kiln 5 (the dry kiln with pre-heater/pre-calciner, as found at the Solnhofen plant) and Kilns 1-4 (the long wet kilns, which usually operate as kilns 1 and 4 in tandem, or 2 and 3 in tandem). Neither the alkali percentages, the sulfur fuel percentages nor the stack concentrations (extrapolated to

uncontrolled for TXI #5) would be considered high for SCR utilization in coal-fired power plants (see Confidential Attachment – TXI).

With respect to the dry kiln (TXI 5), it would be expected that an SCR system would be installed downstream of the pre-heater, where the temperature would be in the range required. With respect to process economics, this temperature is assumed to be 700°F (the temperature utilized in all the cases at all the plants studied). With respect to this particular kiln, the present data indicates a low NO_x level in the 150-ppm range. For conservatism, it is therefore assumed that an SCR system for this kiln would operate at an 80% reduction efficiency, as opposed to a significantly higher level (85%) to be expected at the other kilns at TXI and at the other facilities in Ellis County.

The economic analysis for this case is found in the confidential attachments. It is found that the cost effectiveness, based on NO_x removed (\$/ton NO_x removed) is approximately \$2,200/ton. With respect to cost effectiveness based on metric tonnes of clinker produced (\$/tonne clinker), the cost is approximately \$0.87/tonne.

The wet kilns have been economically modeled based on a number of possible scenarios. The reported stack gas temperature 160°C (320°F) was utilized in the reheat calculations (to 700 °F at the SCR inlet) in all cases, and natural gas, at \$12.00/therm is utilized. Three different scenarios were studied. In the first scenario, one SCR system serves kilns 1 and 4 consistent with TXI's operation (85% of the time). In the second scenario, one SCR system serves kilns 2 and 3 again consistent with TXI's operation (15% of the time). In the third scenario, one SCR system serves all four wet kilns with piping and controls to match the normal operating scenarios. These three scenarios were again modeled based on the possibility that TXI might introduce mid-kiln firing as a method of NO_x control in its four wet kilns. Therefore, a total of six economic analyses for the TXI wet kilns are found in the confidential attachment.

For the scenario without mid-kiln firing in kilns 1 and 4, the cost effectiveness based on NO_x removal (\$/ton NO_x removed) is approximately \$5,500/ton. The cost effectiveness based on metric tonnes of clinker produced (\$/tonne clinker) is approximately \$8.90/tonne. These estimates are based on the assumption that mid-kiln firing is in place as required under the

existing Texas regulations. Mid-kiln firing is currently required at Ash Grove, but has not been installed due to permit issues. Assuming mid-kiln firing avoids possible double counting of the emissions reductions achieved by mid-kiln firing.

The scenarios involved with kilns 2 and 3 with SCR lead to what must be considered unacceptable economics, since capital cost is essentially equal to that for kilns 1 and 4, but operation (both from the standpoints of NO_x removed and clinker produced) is only 15% of the total. Therefore, without mid-kiln firing, the economics yields a cost effectiveness based on NO_x removal of approximately \$96,000/ton, while the cost effectiveness based on clinker produced is in the \$13.50/tonne range. Mid-kiln firing is also assumed for kilns 2 and 3.

Based on economies of scale, utilizing one large SCR unit to service all four kilns (the model assumes a capacity equivalent to approximately 3 kilns in operation at any time) should lead to the most cost effective manner of control. With mid-kiln firing, the cost effectiveness based on NO_x removal is approximately \$5,300/ton, while the cost effectiveness based on clinker produced is about \$5.90/tonne.

It is clear that while the reheat required in the wet kilns significantly increases the costs associated with NO_x control with the utilization of SCR, the cost effectiveness is best when one SCR unit is installed for all four wet kilns. For the dry kiln, the economics is, of course, significantly better and assuming space for the catalyst beds and ancillary equipment is available, SCR must be seriously considered.

SCR at the Holcim Kilns

To consider SCR at the Holcim facilities, separate analyses are performed for each of the two dry units. Each is equipped with precalciners and preheaters, but Holcim 2 is a newer, more efficient unit, emitting 26% less NO_x (in mg/m³). The temperature after the preheater for both Holcim 1 and 2 is expected to be adequate (i.e. 700°F), so no reheat would be required, and 85% NO_x removal is assumed. Neither the alkali percentages, the sulfur fuel percentages, nor the stack concentrations extrapolated to uncontrolled would be considered high for SCR utilization

in coal-fired power plants (see Confidential Attachment – Holcim). The utilization of SCR is, therefore, not precluded.

The annual cost spreadsheets are found in the confidential attachments for each cement plant. The cost effectiveness based on NO_x removal (\$/ton NO_x removed) for Holcim 1 is approximately \$1,950/ton. The cost effectiveness based on metric tonnes of clinker produced (\$/tonne clinker) is about \$2.00/tonne.

For Holcim 2, which is more efficient, the NO_x removed is less (since less NO_x is produced) and the clinker production is greater. Therefore, the cost efficiency based on NO_x removal is slightly greater for Holcim 2, at approximately \$2,000/ton, and the cost effectiveness based on tonnes of clinker produced is approximately \$1.70/tonne.

SCR at the Ash Grove Kilns

Ash Grove has three wet kilns with mid-kiln firing: Ash Grove 1, Ash Grove 2 and Ash Grove 3. Data indicate nearly identical operating conditions and NO_x emission levels (in the 350 ppm to 400 ppm range). Neither the alkali percentages, the sulfur fuel percentages nor the stack concentrations would be considered high for SCR utilization in coal-fired power plants (see Confidential Attachment – Ash Grove). In addition, Ash Grove reports temperatures at the air pollution control device (APCD) inlets of 330°F to 370°F. Assuming the installations of SCR between the APCDs and the stacks, these temperatures indicate that Ash Grove can install SCR at each of their kilns with reheat required, and 85% NO_x removal can be expected.

Four scenarios are presented, that of the installation of an SCR at each of the three wet kilns, the fourth being the installation of one SCR for all three units. For Ash Grove 1, the cost effectiveness based on NO_x removal (\$/ton NO_x removed) is about \$5,800/ton (all reheat at \$12.00/therm). The cost effectiveness based on clinker produced (\$/tonne clinker) is approximately \$9.20/tonne.

For Ash Grove 2, the cost effectiveness based on NO_x removal is approximately \$5,800/ton. The cost effectiveness based on clinker produced is about \$9.90/tonne.

For Ash Grove 3, the cost effectiveness based on NO_x removal is approximately \$6,100/ton. The cost effectiveness based on clinker produced is approximately \$10.60/tonne clinker.

If space is available and operation is not impeded, one SCR unit can be installed to service all three kilns. In this case, the cost effectiveness based on NO_x removal improves to about \$4,600/ton. The cost effectiveness based on clinker production improves to approximately \$7.70/tonne.

It is clear that if space is available for one SCR unit and its ancillary equipment, in order to serve all three kilns, the economics is far more favorable than if three SCRs are installed. SCR, therefore, for these wet kilns is an available technology at 85% NO_x control, albeit at a high cost/tonne of clinker removed.

Table 4-1.1. Summary of Modeling Results for SCR on Ellis County Kilns – Performance Results

Existing Unit	Control Technology	Emissions Rate tpy before	Emissions Rate tpy after (a)	Controlled Emissions Rate ppm	Controlled Emission Rate lb./tonne clinker	Control Efficiency %	Reduction tpy
Ash Grove #1- wet	SCR	702	301.6	60	0.84	85%	400.4
Ash Grove #2- wet	SCR	750	322.2	58	0.89	85%	427.8
Ash Grove #3- wet	SCR	764	328.3	53	0.91	85%	435.7
Ash Grove #1,2,&3 (c)	SCR	2205	947.4	57	0.88	85%	1,257.6
TXI #1 and #4–wet (b)	SCR	838	155.3	109	0.85	85%	478.0
TXI #2 and #3–wet (b)	SCR	121	52	109	0.51	85%	69.0
TXI #1,2,3,4 –wet (c)	SCR	1802	774.2	109	0.85	85%	1,027.8
TXI#5 – dry	SCR	1710	734.7	29	0.30	80%	975.3
Holcim #1 – dry	SCR	2222	954.7	108	0.56	85%	1,267.3
Holcim #2 – dry	SCR	1778	763.9	80	0.45	85%	1,014.1

(a) NO_x emission rate after SCR does not reflect SCR efficiency reduction due to adjustment by the ozone season factor of 0.671 (NO_x reduction is modeled to occur only during the ozone season).

(b) The results for TXI 1 & 4 and #2 & #3 are average per kiln – for example, total emissions reductions for controlling both TXI #1 & #4 are double the value listed in the table.

(c) A large single SCR was modeled for the Ash Grove and TXI wet kilns with the capacity of 3 wet kilns.

(d) Models assume mid-kiln firing installed at TXI as required under current SIP.

Table 4-1.2. Summary of Modeling Results for SCR on Ellis County Kilns – Economic Results

Existing Unit	Control Technology	Capital Cost	Annual Cost	Cost Effectiveness \$/ton NO _x	Energy Penalty or Benefit	Emissions Penalty or Benefit	Burden Cost \$/tonne clinker
Ash Grove #1- wet (e)	SCR	\$5.0MM	\$2.3 MM	\$5,800	(a)	(b)	\$9.20
Ash Grove #2- wet (e)	SCR	\$5.2MM	\$2.5MM	\$5,800	(a)	(b)	\$9.90
Ash Grove #3- wet (e)	SCR	\$5.3MM	\$2.7MM	\$6,100	(a)	(b)	\$10.60
Ash Grove #1,2,&3(d)	SCR	\$11.8MM	\$5.7 MM	\$4,600	(a)	(b)	\$7.70
TXI #1 & #4–wet (c,e)	SCR	\$5.7MM	\$2.6MM	\$5,500	(a)	(b)	\$8.90
TXI #2 & #3–wet (c,e)	SCR	\$5.7MM	\$0.6MM	\$96,000	(a)	(b)	\$13.50
TXI #1,2,3,4 –wet (d,e)	SCR	\$11.2MM	\$5.4MM	\$5,300	(a)	(b)	\$5.90
TXI#5 – dry	SCR	\$8.4MM	\$2.2MM	\$2,200	(a)		\$0.87
Holcim #1 – dry	SCR	\$7.5MM	\$2.4MM	\$1,900	(a)		\$2.00
Holcim #2 – dry	SCR	\$6.7MM	\$2.0MM	\$2,000	(a)		\$1.70

(a) Increased fan power due to pressure drop across catalyst bed included in the models

(b) Increase in NO_x from gas reheat occurs, but is controlled by the SCR

(c) The results for TXI #1 & #4 and #2 & #3 are average per kiln – for example, total capital costs for controlling both TXI #1 & #4 are double the value listed in the table.

(d) A large single SCR was modeled for the Ash Grove and TXI wet kilns with the capacity of 3 wet kilns.

(e) Costs for wet kilns include cost of RTO to reheat flue gas.

4.1.2 Selective Noncatalytic Reduction (SNCR)

This control technique relies on the reduction of NO_x in exhaust gases by ammonia or urea, without using any catalyst, with the same reactions as in the case of the SCR process. Because of low capital and maintenance costs associated with this technology vis-à-vis other end-of-pipe technologies like SCR and oxidative methods, it is likely to command attention in the near future within the industry. This approach combines a low initial capital cost and avoids the problem related to catalyst fouling and replacement associated with SCR technology. SNCR requires injection of the reagents in the kiln at a temperature between 870 to 1,090°C (1,600 to 2,000°F). In principle, any of a number of nitrogen compounds may be used as SNCR reagents (e.g., cyanuric acid, pyridine, and ammonium acetate). However, for reasons of cost, safety, simplicity, and by-product formation, ammonia and urea have been used in most of the SNCR applications. The selection of reagents is process and temperature specific. At higher temperatures, urea decomposes to produce ammonia, which is responsible for NO_x reduction. In cement kiln applications, ammonia typically has performed best as the reducing reagent.

Because no catalyst is used to increase the reaction rate, the temperature window is critical for conducting this reaction. At higher temperatures, the rate of a competing reaction for the direct oxidation of ammonia, which actually forms additional NO_x , becomes significant. At lower temperatures, the rates of NO_x reduction reactions become too slow resulting in too much unreacted ammonia being released to the atmosphere (i.e., ammonia slip). The effective temperature window range can be lowered to about 700°C (1,300°F) by the addition of hydrogen along with the reducing agent. (24) Addition of hydrogen can promote SNCR reactions (enhanced SNCR), but high levels of sulfur oxides may interfere with this reaction (Recent evidence tends to call into question this tentative conclusion). Nalco Fuel Tech, the producer of the SNCR technology $\text{NO}_x\text{OUT}^{\text{®}}$, has also introduced $\text{NO}_x\text{OUT}^{\text{®}}$ PLUS which is said to broaden the operating temperature window and to reduce ammonia slip and CO and NO_2 formation.

In a conventional long kiln, the appropriate temperature window is in the middle of a kiln. Until quite recently, because of the rotating nature of a long kiln, continuous injection of ammonia- or urea-based reagents had not been considered possible. The technology developed

for mid-kiln firing of containerized solid fuels allows injection of a certain amount of material once during the kiln revolution. Injection of solid ammonium or urea salts in this manner had not been used because of the assumption of rapid decomposition of such salts. Therefore, SNCR technology had not been thought applicable to date for long dry or wet kilns. There is some limited evidence from Europe, suggesting that injection of urea into long wet kilns may have promise(25). Urea injection was reportedly continued over a four month period with satisfactory results at a wet kiln in France. The publicized information does not, however, give detailed data needed to evaluate this test. The test does not stipulate:

- Location of reagent injection,
- Titration rate for reagent,
- Reagents tried and their performance (only urea is mentioned),
- NO_x reduction rate vs. titration rate,
- NO_x reduction rate vs. temperature,
- Average NO_x emissions rates for controlled and uncontrolled operation,
- Operating costs,
- Other NO_x control measures employed at the kiln, and
- A physical description of the kiln and information on feed and production materials. (25)

Without this type of detailed information, it is difficult to draw any definitive conclusions about the potential for application to wet kilns in Ellis County.

In addition, Fuel Tech Inc. is currently evaluating dry dust or pellet injection methods for direct injection into kilns. (26) The possibility of injection of ammonia or solid urea inside automobile tires that are injected into the kiln has still to be evaluated. With the known ability of mixing air fans to induce turbulence in the system, mixing combustion gases containing NO_x with ammonia, either generated from urea or from ammonium salts, may also offer possibilities. Chain gas temperatures generally are in the range of 1500-1600°F (815-871°C). The mid-kiln injection systems are usually down kiln somewhat from this point, which means that they will be higher than this in gas temperature. There is a good possibility that the correct temperature range can be achieved if mixing is induced and volatilization or decomposition of the urea can be delayed by inserting it in a solid form in a carrier such as a tire. This option needs to be explored. It will clearly be necessary to mix the NO_x with the reagent before the latter has an opportunity for decomposition. Inducing turbulence is presently conceived as a key element in this strategy.

In preheater/precalciner type cement kilns, the temperatures at the cooler end of the rotating kiln, in the riser duct, and in the lower section of the cyclone preheater tower are likely to be in the temperature window appropriate for SNCR. Such kilns are therefore good candidates for application of SNCR technology.

The NO_x reduction efficiency of SNCR depends upon the temperature, oxygen, carbon monoxide, and residence time, as well as the ammonia and NO_x concentrations in the flue gas. Injection of ammonia at a $\text{NH}_3:3 \text{ NO}_x$ proportion of 1 to 1.5 will reduce NO_x emissions between 60 to 80 percent. Using a molar ratio of 0.5 will give NO_x reductions of approximately 40 percent. (27) Work done by the German equipment supplier Polysius (28) has shown that the optimum temperature for reduction of NO_x by ammonia is about 950°C ($1,740^\circ\text{F}$), while for urea, the temperature increases to about $1,000^\circ\text{C}$ ($1,830^\circ\text{F}$). Ammonia is also somewhat more efficient, as shown in Figure 4-1.2. below.

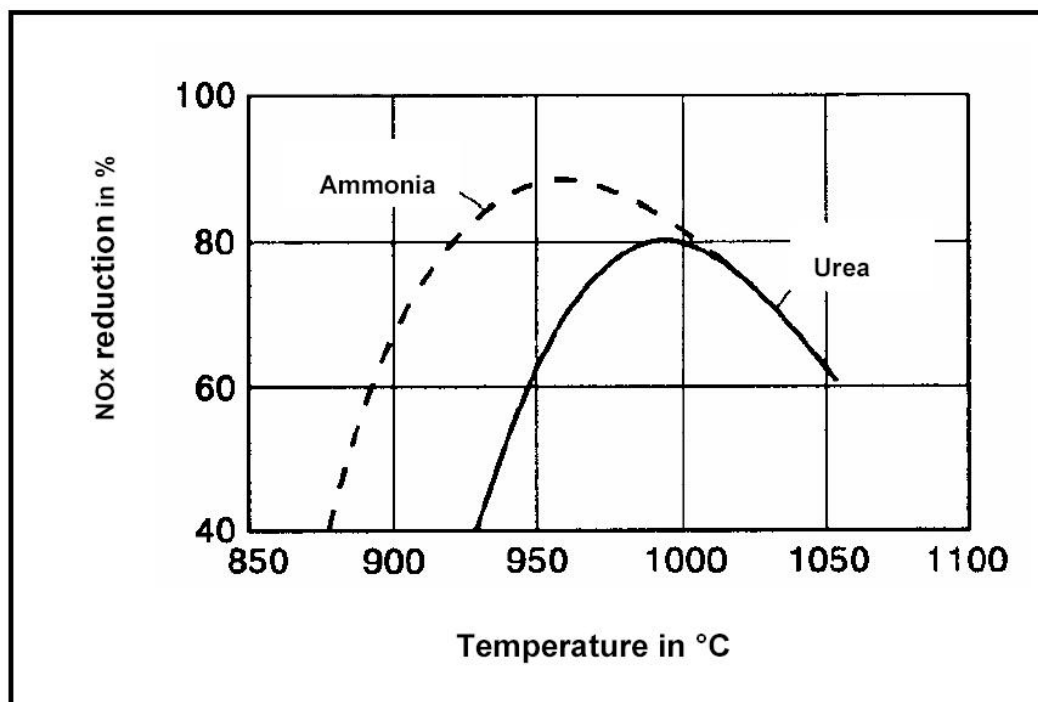


Figure 4-1.2. Dependence of NO_x Reduction on Temperature for Ammonia and Urea

Actual SNCR results with ammonia (19% aqueous solution) at one US plant employing a calciner are given in Table 4-1.3. It can be seen that the reduction was remarkably good, considering that ammonia was never added at greater than a stoichiometric equivalent to NO_x

Due in part to the fact that no excess ammonia was introduced into the system, no ammonia slip was demonstrated. The ammonia emissions were undetectable.

Table 4-1.3. Summary of Test Results for SNCR Test

Run #	Molar Ratio NH ₃ :NO	NO _x Reduction %	Average NO _x Before lb./hr	Average NO _x During SNCR lb./hr
1	0.918	65.49%	325.47	112.31
2	0.533	36.71%	322.90	204.35
3	0.425	44.93%	345.52	190.27
4	0.331	16.90%	282.70	234.91
5	0.465	15.49%	290.18	245.25
6	0.286	12.95%	269.35	234.47
7	0.534	45.06%	269.35	147.97
8	0.552	31.91%	281.71	191.81
Long term	0.368	47.78%	329.83	172.24

These results were very good. The temperature and oxygen concentrations were nearly optimum for the SNCR system. The carbon monoxide levels were somewhat higher than has been considered optimum, but according to Brouwer et al. (29), CO may promote the reaction at the lower end of the temperature range, because of the temperature increase due to the heat given off by the reaction of CO with OH radicals. Among other SNCR tests recently performed, tests have been carried out at a preheater plant and four calciner plants. Some of these tests were carried out using ammonia, and others using urea. At the preheater plant, both ammonia and urea were tested, injecting the reagents into the kiln riser duct. Ammonia proved to be considerably more effective than urea, in keeping with the Polysius plot given above.

Despite these successes, reagent consumption can be significantly higher with greater ammonia slip in SNCR systems as compared to SCR systems. Operating experience has identified several concerns with both ammonia and urea-based SNCR processes. The most frequently reported is the buildup of ammonium bisulfite or bisulfate scale, which is significant for sulfur-containing fuels. SNCR processes also appear to convert some NO_x to N₂O. (30) The rate of N₂O formation is a weak function of both the reactant and the NO concentration. However, N₂O formation seems to be inherently more prevalent in systems using urea than those using ammonia. (31)

The NO_x destruction efficiency also depends upon the flue gas residence time in the appropriate temperature window. Unlike an SCR system where the reaction temperature is controlled in a dedicated reactor, an SNCR system relies on the existing gas temperature profile to provide an adequate residence time for a desired NO_x destruction. Maximum achievable NO_x reduction in a cement kiln may thus depend upon the gas temperature profile.

The SNCR process was demonstrated in Europe in a preheater type kiln. Both ammonia- and urea-based reagents were investigated. The reagents were injected in the gas duct as shown in Figure 4-1.3. (32) With a molar ratio of reagent to NO_2 of 1:1, about 70 percent reduction in NO_x emissions was observed with ammonia-based reagent and about 35 percent NO_x reduction was obtained with urea. (32) With this reagent ratio, there was no major increase in ammonia emissions in exhaust gases over the background level of ammonia emissions generated by kiln feed material. Greater NO_x reductions were observed with more than stoichiometric amount of reagent, although there was increasing ammonia 'slip' in the exhaust gases.

Figure 4-1.3. Application of SNCR at Holcim



Albert Scheuer, of the Research Institute of the Cement Industry in Düsseldorf, Germany, reported on 148 SNCR trials carried out on five different kilns. Three kiln systems had cyclone preheaters and two had grate preheaters. A 25% molar concentration of NH_3 in water was the main reagent tested, with some additional testing done with ammonium sulfate solutions and

with urea solutions. Scheuer reported that NO reductions with the NH₃/water solution ranged from 15% to 75% and that temperature appeared to be one of the main determinants of the effectiveness of the reagent. Maximum NO reduction occurred at 980°C (1796°F). NH₃ escape occurred when temperatures were less than 900°C (1652°F) and when the NO concentration fluctuated. NH₃ utilization decreased significantly with increasing NH₃:NO molar ratio and with decreasing NO concentration in the exhaust gases, indicating that SNCR appears to be a less promising methodology at low NO emissions rates. (33,34)

SNCR is presently being used in 18 cement kilns in Europe. Fifteen kilns are in Germany, two are in Sweden, and one is in Switzerland. These kilns are either suspension preheater kilns or precalciner kilns. The names and locations of these installations have not been found in any of the European references that discuss these installations. The most common reagent used is 25% ammonia water. (35) NO_x reduction rates vary from 10 to 50 percent with NH₃/NO₂ molar ratio of 0.5 to 0.9, NO_x emissions at these reductions are 2.4 to 3.8 lb./tonne clinker. Two dry process cyclone preheater/precalciner kilns in Sweden achieve 80 to 85 percent reduction (1.0 lb./tonne clinker) at a NH₃/NO₂ molar ratio of 1.0 to 1.1. (35) One reason for the remarkable results in these kilns is the use of multiple injection points (12 in all) that ensure long enough retention time for the reaction to take place. The optimum temperature is said to be 900-1,100°C (1,650-2,010°F) in good agreement with other authors. These results suggest that some SNCR tests may have been carried out under lower-than-optimum temperatures.

F. L. Smidth and Company tested SNCR on a preheater/precalciner kiln. (36) Ammonia was injected into the lower cyclone of the preheater tower where temperatures are favorable for the reduction reactions to occur. NO_x emissions reductions during this experiment averaged 40 percent, but NO_x reductions of over 90 percent were obtained when the ammonia injection rate was 10 to 20 percent in excess of stoichiometric.

In North America, SNCR has been tested on at least nine kilns. In some of the earlier work, NOxOUT[®] technology was tested under ten different operating conditions at a preheater/precalciner kiln in Seattle, Washington during October 1993. NO_x emissions were effectively reduced from 3.5 to 6.0 lb. NO_x/tonne clinker to less than one lb. NO_x/tonne clinker. (37,38) Another test of NOxOUT[®] technology was conducted during October 1998 in

Davenport, Iowa. This test found NO_x reductions of 10 to 20 percent from a baseline of approximately 350 pounds NO_x/hour, although higher levels of reduction are thought to be achievable when the baseline is higher. (39) An evaluation of NOxOUT[®] technology was conducted in 1994 for a long dry kiln in Southern California, but the study concluded that application of the NOxOUT[®] technology at the subject kiln was technically infeasible. (40) The details of this testing are not known.

Biosolids Injection (BSI). The Mitsubishi Cement Corporation's Cushenbury plant in Lucerne Valley, CA, uses biosolids injection technology (BSI) to achieve SNCR of NO_x. The BSI process was developed by the Cement Industry Environmental Consortium (CIEC). The founding participants in the CIEC are Southdown, Inc., Riverside Cement Company, Mitsubishi Cement Corporation, California Department of Commerce (now Trade & Commerce Agency), and the San Bernardino County Air Pollution Control District (now Mojave Desert Air Quality Management District). This technology is covered under U.S. Patent No. 5,586,510 issued December 24, 1996. (33)

The basic principle is to utilize the naturally occurring ammonia content of dewatered biosolids as the reagent. The dewatered biosolids are obtained from wastewater treatment plants. Since the biosolids are mechanically dewatered without heat input, the solids content varies between 16 and 30 percent (moisture content of 84 to 70%). Depending on the moisture content, the net Btu content (after evaporating the moisture) of the biosolids varies between -750 and +2200 Btu/lb. Since the biosolids heating value is relatively small, the net effect on kiln fuel combustion is expected to be small. (41)

The same conditions that affect NO_x reduction performance in SNCR affect BSI performance: temperature (927°C / 1,700°F is optimal), residence time (> 0.5 seconds is desirable), inlet NO_x concentration, inlet CO concentration, and NH₃/ NO_x molar ratio. Another key issue is mixing effectiveness, which affects the extent of contact and, hence, reaction between NH₃ and NO_x. The BSI technology is applicable to preheater/precalciner kilns because the temperature window for BSI (927°C / 1700°F) occurs in a location where it is feasible to inject biosolids. (41)

The biosolids are injected into the mixing chamber where the flue gas stream leaves the kiln and precalciner mix. The mixing chamber offers the benefits of good residence time in the appropriate temperature window (927°C / 1700°F) and high mixing effectiveness. (41)

At the Cushenbury plant, BSI underwent long-term testing and eventual adoption in 1994 and 1995. The kiln is fueled with coal (85 percent) and tires (15 percent). The plant began using tire-derived fuel (TDF) in mid-1993, so it is difficult to isolate the effects of TDF or BSI on NO_x emissions. The company estimates that the use of TDF reduces NO_x emissions from the kiln by 30 to 40 percent. (42) Before the SNCR technology was adopted, the company estimated NO_x emissions averaged 2.4 lb./tonne clinker; afterwards, the average fell to 1.2 lb./tonne clinker, a 50 percent reduction. The effects of BSI on CO emissions varies between a large increase and no change at all, but in all cases it has remained below 500 ppm. BSI has not caused any significant changes in either metal HAP or organic HAP emissions. Using the SNCR biosolids technology, the kiln also reduced its fuel consumption by 5 percent. (41)

NOxOUT[®]. An SNCR process using aqueous urea was developed by Electric Power Research Institute (EPRI) and is now marketed by Nalco Fuel Tech, Inc., under the trade name NOxOUT[®]. In the urea reaction with NO, one mole of urea reacts with two moles of NO to complete the reaction to nitrogen, carbon dioxide and water. Normalized Stoichiometric Ratio (NSR) is used to express the reagent feed rate relative to the reaction stoichiometry. The NSR takes into account the 2:1 mole ratio of the NO:urea reaction as the “normalized” ratio. If 50% of the urea reacts to reduce NO to nitrogen, reduction of 100% NO_x occurs at NSR=2; 80% reduction at NSR=1.6; 50% reduction at NSR=1.0, etc. Performance improves with increased turbulence or mixing, residence time, and more favorable temperature conditions. A higher NO_x baseline generally leads to a higher percentage of NO_x reduction. (26)

Urea is safer to handle than anhydrous ammonia. Both ammonia and urea need to be injected in a similar temperature window, which is 870 to 1090°C (1600 to 2000°F). The Polysius results earlier noted, however, appear to suggest that the ammonia optimum may be lower than the urea optimum. Proprietary additives have been developed by Nalco to widen the temperature window. (43) One modification of the urea-based SNCR system is the addition of methanol injection downstream of the urea injection point to improve overall NO_x removal.

Nalco also introduced an improved NOxOUT[®] PLUS, which is said to further broaden the operating temperature window and to reduce ammonia slip and CO and NO₂ formation.

The Ash Grove plant in Seattle is a preheater/precalciner kiln with average processing rates of 160 tons dry feed/hour producing approximately 100 tonnes clinker/hour. NOxOUT[®] was tested on this kiln under varying conditions, including the use of different fuel types (natural gas and coal), heat input to the calciner (5 to 9 percent), and preheater O₂ (1.8 to 2.9 percent). (It is probably necessary to point out that this calciner is an example of the so-called “air through” unit which employs no tertiary air duct; all air for combustion in the calciner must be furnished through the kiln. As of the present time, this heat input is in the range of 20-30% of the total. The baseline NO_x levels varied from 350 to 550 lbs. NO_x/hour. When NOxOUT[®] was used, NO_x emission reductions varied significantly depending on the conditions, with a maximum reduction of 90 percent (less than 100 lbs. NO_x/hour). Typical reductions were greater than 50%. (38)

NOxOUT[®] was tested for one week in October of 1998 on the preheater/precalciner kiln at the Lafarge-Davenport Plant. Operating conditions were unstable most of that week and only five hours of testing produced results that could provide a reasonable indication of what may be achievable with NOxOUT[®]. The baseline NO_x rate was approximately 350 lbs. NO_x/hour. Using NOxOUT[®], emission reductions of 10 to 20 percent were achieved. (39) Operating conditions such as residence time, temperature, and the use of coal at this kiln were contrasted to conditions at the Ash Grove kiln that achieved greater reductions to explain why NOxOUT[®] may achieve better results on some kilns than others.

Nalco also has conducted a number of demonstrations and commercial projects in preheater/precalciner cement kilns. The fuels have included coal, and coal in combination with No. 6 heavy fuel oil, waste oil, and/or tire chips. The clinker capacity on these kilns ranged from approximately 1,000 metric tons to 3,200 metric tons per day. The results of two tests with average NO_x reductions of approximately 50%, were featured in a recent report (see Table 4-1.4). (26)

Table 4-1.4. Emissions Reductions From Two Kilns Using NO_xOUT[®]

	Baseline NO_x Emissions (ppm)	NO_x Emissions with NO_xOUT[®] (ppm)	Percent Reduction (%)
Kiln A, Test 1	412	203	51
Kiln A, Test 2	389	185	53
Kiln B	525	284	46

Site-Specific Analyses

SNCR at Holcim

Holcim Kiln #1

Holcim carried out trial SNCR tests on both of their precalciner kilns in Midlothian, TX. For the injection in line 1, (the older unit) the optimum location was identified to be on the riser duct, after the precalciner and before the bottom stage cyclone. This location would address NO_x formed both in the kiln (principally presumably thermal NO_x) and in the calciner (principally presumably fuel NO_x). The reports do not indicate the temperature, oxygen, or carbon monoxide concentrations of the flue gas, considered very important for optimum efficiency. There is therefore no basis for concluding that conditions had been optimized. With this condition, it proved possible to obtain about 50% removal of NO_x at a molar ratio of ammonia to NO_x of 0.75. This is not considered to be as good as obtained in the Florida kiln indicated earlier, nor for some of the Northern European kilns. However, the removal efficiency appears to be in good agreement with the data cited earlier, where a molar ratio of 0.5 is cited as achieving 40% removal, while a molar ratio of 1.0 is said to achieve 60% removal. While the conditions may not have been optimized, the results are considered acceptable compared to performance at other similar kilns. Experience at other kilns indicates further optimization may result in better performance at Holcim #1 than was achieved during the initial trial period.

Holcim Kiln #2

For the Kiln #2 system, the injection point was on the riser duct after tertiary air input and before the Pyroclon (calciner). This differs from the location for the Kiln #1 system, where the

injection point is post-calciner. This difference implies that the gases from the calciner were treated in the Kiln #1 system, but no SNCR was applied to calciner exhaust gases in the Kiln #2 system. Experience to date suggests that with normal bituminous coal fuel, roughly 70% of the system NO_x may be generated in the kiln, and 30% in the calciner as a general rule of thumb. To the extent that this supposition is justified, it appears as though an SNCR injection location that does not treat gases from the calciner may be omitting treatment of about 30% of the NO_x . In addition, the injection location for this kiln system may be experiencing a temperature decrease from the cooler tertiary air. Any residual carbon monoxide from the kiln exit gases was probably oxidized by the high O_2 content at this location, further compromising the results. If this is the case, further erosion of the efficiency of the SNCR system may be occurring.

As a result, with a molar ratio of 0.75, the efficiency of removal of NO_x was only 35%. This cannot be considered satisfactory. It proved possible to increase the NO_x removal to as high as 80%, but this was with a molar ratio of about 2.0. At this molar ratio, ammonia slip and detached plumes were severe. In addition, the plant reported a buildup of ammonium sulfate/ammonium bisulfate in the top preheater stage forming under conditions of high ammonia injection. They claim that this buildup had the potential to assume catastrophic dimensions, but was removed before this occurred.

It does not appear likely that the location for NO_x removal on Kiln #2 was optimized. The lack of any data on temperature, oxygen, and/or carbon monoxide suggests that these data were not collected. It was discovered during the Florida test that optimization of these parameters was important to the success of the experiment. We believe that if the conditions are properly optimized using the necessary temperature, oxygen, and CO data, that better results are achievable at Holcim#2.

SNCR at TXI

TXI Kiln #5

This kiln is already achieving very good NO_x control without employing any end of pipe technologies. It appears that the kiln is running at about 1.9 lb. NO_2 /tonne clinker at present –

this may be the lowest value for any Portland cement kiln in the country. The application of SNCR may be worth consideration for further reduction of NO_x. It should be recognized, however, that 35% removal may be the best achievable, and even this level may not be achievable without optimization of the location in the preheater tower for temperature, oxygen, and CO. SNCR becomes less effective at lower NO_x concentration and European experience indicates that 200 mg/m³ or approximately 100 ppm may be a lower limit for efficient application of SNCR at cement kilns. As earlier indicated, TXI has a high level of relatively nonvolatile organic carbon, a high level of total Kjeldahl nitrogen (unfortunately, the temperature profile of nitrogen release from the feed at TXI is not known), and an apparently relatively easy burning mix. All these factors mitigate in the direction of lower uncontrolled NO_x numbers.

TXI Wet Kilns

The ERG Team has estimated that the TXI wet kilns are currently operating at over 8 lb. NO₂/tonne clinker. The Texas Code (Chapter 117) requires mid-kiln injection or meeting an emissions limitation of 4.0 lbs./tonne clinker. For the purposes of modeling SNCR and other control techniques on the TXI wet kilns, a 30% reduction in NO_x emissions is assumed to result in emissions similar to the Ash Grove wet kilns when the mid-kiln firing is installed. The ERG Team understands that TXI is waiting for permit approval to convert the wet kilns to mid-kiln firing with tire injection. As discussed above, the lack of available alternative NO_x controls for wet kilns leads the ERG Team to a recommendation of trying innovative or experimental techniques involving some SNCR injection involving urea or another reagent in tires. This experimentation would determine if mixing and the proper form of ammonia might travel into the proper temperature range of the kiln to be effective. These ideas will have to be verified or disproved with experimentation. For the purposes of cost modeling, a 35% efficiency is assumed to be achievable through a mid-kiln injection of a SNCR reagent.

SNCR at Ash Grove

Ash Grove Wet Kilns

The Ash Grove wet kilns are already using mid-kiln firing and are emitting approximately 5.0 lbs./tonne clinker. Mid-kiln firing is traditionally regarded as the most

effective wet kiln method for controlling NO_x. As discussed above, it may be worthwhile considering a modification of traditional SNCR here, in which the urea is introduced inside whole tires, and mixing air is used to promote reaction with NO_x before the urea is decomposed. This is innovative and speculative, and requires testing to verify, but it should be quite inexpensive and cost effective for a plant already employing mid-kiln firing. Attempting an innovative control method for wet kilns based on SNCR seems to be a worthwhile option since other control options have not been applied to wet kilns. SCR and LoTOxTM appear to be transferable from other applications but have high costs associated with reheating the flue gas in the case of SCR and installing a spray tower in the case of LoTOxTM. As mentioned in evaluating TXI #5, there appears to be the potential for some NO_x reduction to be occurring from the materials already being fed to this kiln. With other mid-kiln injection in long kilns, NO_x reduction has occurred through feeding nitrogen containing sands at mid-kiln. It might be possible to introduce another material high in non-volatile carbon and/or TKN nitrogen at mid-kiln to see whether the foregoing explanation for the low NO_x from the TXI kilns is valid. Again, this would not be expensive as an experimental investigation. Similar to the TXI wet kilns, for the cost models, it was assumed that one of these experimental techniques could result in 35% NO_x reduction and that the costs would be similar to the costs of installing SNCR on a utility boiler.

Table 4-1.5. Summary of Modeling Results for SNCR on Ellis County Kilns – Performance Results

Existing Unit	Control Technology	Emissions Rate tpy before	Emissions Rate tpy after (a)	Controlled Emissions Rate ppm	Controlled Emission Rate lb./tonne clinker	Control Efficiency %	Reduction tpy
Ash Grove #1- wet	SNCR	702	537.1	200	3.6	35%	164.9
Ash Grove #2- wet	SNCR	750	573.9	200	3.9	35%	176.1
Ash Grove #3- wet	SNCR	764	584.6	200	3.9	35%	179.4
TXI #1 and #4-wet (b)	SNCR	838	641.2	250	3.7	35%	196.8
TXI #2 and #3-wet (b)	SNCR	121	92.6	250	3.7	35%	28.4
TXI#5 – dry	SNCR	1710	1,308.4	100	1.0	35%	401.6
Holcim #1 – dry	SNCR	2222	1,476.5	190	1.9	50%	745.5
Holcim #2 – dry	SNCR	1778	1,181.5	150	1.5	50%	596.5

(a) NO_x emission rate after SNCR does not reflect SNCR efficiency reduction due to adjustment by the ozone season factor of 0.671 (NO_x reduction is modeled to occur only during the ozone season).

(b) The results for TXI 1 & 4 and #2 & #3 are average per kiln – for example, total emissions reductions for controlling both TXI #1 & #4 are double the value listed in the table.

Models assume mid-kiln firing installed at TXI as required under current SIP.

Table 4-1.6. Summary of Modeling Results for SNCR on Ellis County Kilns – Economic Results

Existing Unit	Control Technology	Capital Cost	Annual Cost	Cost Effectiveness \$/ton NO _x	Energy Penalty or Benefit	Emissions Penalty or Benefit	Burden Cost \$/tonne clinker
Ash Grove #1- wet	SNCR	\$1.2 MM	\$0.4MM	\$2,500	(a)	(b)	\$1.70
Ash Grove #2- wet	SNCR	\$1.3MM	\$0.4MM	\$2,400	(a)	(b)	\$1.70
Ash Grove #3- wet	SNCR	\$1.4MM	\$0.4MM	\$2,400	(a)	(b)	\$1.70
TXI #1 and #4–wet (c)	SNCR	\$1.4MM	\$0.5MM	\$2,400	(a)	(b)	\$1.60
TXI #2 and #3–wet (c)	SNCR	\$1.4MM	\$0.3MM	\$13,000	(a)	(b)	\$5.00
TXI#5 – dry	SNCR	\$2.3MM	\$1.0MM	\$2,900	(a)		\$0.45
Holcim #1 – dry	SNCR	\$2.3MM	\$1.1MM	\$1,500	(a)		\$1.00
Holcim #2 – dry	SNCR	\$2.3MM	\$1.0MM	\$1,700	(a)		\$0.90

(a) SNCR should not have energy impacts.

(b) Ammonia slip can be significant for SNCR when not properly optimized.

(c) The results for TXI 1 & 4 and #2 & #3 are average per kiln – for example, total capital costs for controlling both TXI #1 & #4 are double the value listed in the table.

4.2 Combustion Optimization

This section of the report is taken from the EPA 2000 Report and is included, with minor editing by the ERG Team. This information is included to provide the Texas environmental communities with the comprehensive background information necessary to understand the parameters that dictate NO_x control options at cement kilns. Combustion optimization is largely in place in the Ellis County kilns, with the exception of the TXI wet kilns that are awaiting permits for mid-kiln firing to comply with the requirements of 30 TAC Chapter 117.

Combustion optimization is generally applicable to all types of kilns and is an efficient way to reduce the formation of thermal NO_x. The combustion modifications discussed in this section focus on staging the combustion to minimize combustion at the maximum temperatures. This can be accomplished by modifying the way oxygen or fuel is provided for combustion. For the purposes of this report, the level of emissions reduction contained in 30 TAC Chapter 117 is the level associated with combustion and process optimization. As such, the techniques below have largely been already required and implemented at the Ellis County cement plants. However, the differing performance of the kilns may indicate that more combustion and process optimization could be implemented as part of the effort to reach higher NO_x emissions reductions levels.

4.2.1 Staged Combustion of Air

Staging of combustion air allows combustion of fuel to proceed in two distinct zones. In the first zone, the initial combustion is conducted in a fuel-rich, oxygen-poor flame zone. This zone provides the high temperatures necessary for completion of the clinkering reactions, but the lack of available oxygen minimizes the formation of thermal and fuel NO_x . The lack of sufficient oxygen leads to only partial combustion of the fuel.

In the second, fuel-lean zone, additional (secondary) combustion air is added to complete the combustion process. However, the temperature in this second zone is much lower than the first zone because of mixing with the cooler secondary air, so the formation of NO_x is minimized in spite of the excess available oxygen. This staged approach can be used for combustion of all fossil fuels. Staged combustion is typically achieved by using only a part of the combustion air (primary air) for fuel injection in the flame zone, with remaining secondary air being injected in the subsequent cooler zone.

For effective staging of combustion air to reduce NO_x emissions, cement plants must have indirect-fired kilns. In a direct-fired cement kiln, air used for conveying pulverized coal from a coal mill, i.e., primary air, is typically 17 to 20 percent of the total combustion air. The amount of primary air may be reduced by separating the coal mill air from coal. A cement kiln using less than 10 percent of primary air is an indirect-fired kiln. Conversion of a direct-fired kiln to an indirect-fired kiln involves adding particle separation equipment such as a cyclone or a baghouse and a fan to provide the primary air used to transport the powdered coal from storage to the kiln. An indirect-firing system increases overall energy efficiency by allowing a greater proportion of hot clinker cooler air to be used as secondary combustion air.

4.2.2 Flue Gas Recirculation

In addition to changing the combustion air distribution, the oxygen content of the primary air may be reduced to produce a fuel-rich combustion zone by recycling a portion of the flue gas into the primary combustion zone. (44) The recycled flue gas may be premixed with the primary

combustion air or may be injected directly into the flame zone. Direct injection allows more precise control of the amount and location of the flue gas recirculation (FGR). In order for FGR to reduce NO_x formation, recycled flue gas must enter the flame zone. The FGR also reduces the peak flame temperature by heating the inert combustion products contained in the recycled flue gas.

The use of FGR may not be a viable method of reducing NO_x in a full-size cement kiln burning zone. FGR's effectiveness relies on cooling the flame and generating an oxygen-deficient (reducing) atmosphere for combustion to reduce NO_x formation, conditions that may not be compatible with cement kiln operation. High flame temperature and an oxidizing atmosphere are process requirements to produce a quality clinker product. A cement kiln differs from a utility boiler and other combustion devices because minimum temperatures and an oxidizing atmosphere are required to initiate chemical reactions in a cement kiln in addition to providing the required heat (Btu/tonne clinker). Reduced flame temperatures and reducing conditions in the burning zone of a cement kiln may not be compatible with the production of cement clinker. (33)

Coupling a low-NO_x step burner with flue gas recirculation has been shown to reduce NO_x emissions further in a cement kiln. (45) The additional NO_x reduction attributable to FGR was estimated to be about 15 to 38 percent depending upon the proportion of FGR used. (45) Incorporation of FGR in a cement kiln also results in somewhat increased power consumption and reduced kiln output.

4.2.3 Low-NO_x Burners

Some cement kiln burners, specifically marketed as low- NO_x, burners, typically use 5 to 7 percent primary air (46,47) and thus can be used only on indirect-fired kiln systems. Low-NO_x burners can be installed on any type of kiln. Low-NO_x burners are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The longer, less intense flames resulting from the staged combustion lower flame temperatures and reduce thermal NO_x formation. Some of the burner designs produce a low pressure zone at the burner center by injecting fuel at high velocities along the burner edges. Such a low pressure

zone, as shown in Figure 4-2, (46) tends to recirculate hot combustion gas which is retrieved through an internal reverse flow zone around the extension of the burner centerline. The recirculated combustion gas is deficient in oxygen, thus producing a similar effect as FGR. Combustion of the fuel in the first stage thus takes place in an oxygen-deficient zone before the fuel is diluted in the secondary air. Installing such a burner reduces NO_x emissions from the kiln-burning zone by up to 30 percent. (46,48,49)

Low- NO_x burners have been used by the cement industry for twenty years. (50) Many suppliers offer low-NO_x burners and most of these systems focus on lowering the NO_x formation in the calciner by air or fuel staging, by reburning, or by high temperature combustion. (51) Test data from several different low-NO_x burners are now available. Thomsen, Jensen, and Schomburg reported on tests of a F.L. Smidth in-line calciner low-NO_x system in a preheater/precalciner kiln where different percentages of coal were added to the reduction zone of the precalciner (the remaining coal was added to the oxidizing zone). (51) When 100 percent of the coal was added to the reduction zone of the precalciner, the NO_x content at the preheater exit was reduced by 44 percent relative to when zero coal was added (see Table 4-2.1).

Table 4-2.1. NO_x Emissions from a Precalciner Equipped with a Low-NO_x Burner

Percent Coal Added to Reduction Zone^a (lb. NO_x/tonne clinker)	Nox Emissions^b (lb. NO_x/tonne clinker)	Percent Reduction^c (%)
0	2.8	-
50	1.9	31
100	1.6	44

^aThe remaining percentage of the coal was added to the oxidizing zone.

^bEmission measurements were taken at the preheater exit.

^cPercent reductions are relative to emissions when zero percent of the coal was added; the original measurements were in kg NO_x/tonne clinker to the hundredth place - the percent reductions were calculated using the original measurements, which results in slightly different values than when lb. NO_x/tonne clinker are used.

Steinbiß, Bauer, and Breidenstein reported emissions changes for five kilns before and after the installation of Pyro-Jet low-NO_x burners (see Table 4-2.2). (50) The emission reductions ranged from 15 to 33 percent. Information on kiln-type was not provided.

Table 4-2.2. NO_x Emissions Before and After Installation of Pyro-Jet Low-NO_x Burners

Kiln	Before Installation (ppm)	After Installation (ppm)	Percent Reduction (%)
A	970	650	33
B	not given	not given	30
C	650	460	29
D	900	730	19
E	not given	not given	15

There are two new data sources on emissions reductions from the use of Rotaflam[®] low-NO_x burners. The Pillard Combustion Equipment and Control Systems published data on four kilns, comparing NO_x emissions with a 3 channel burner to emissions when a Rotaflam[®] burner was used (see Table 4-2.3). (52) The emission reductions ranged from 23 to 47 percent. Information on kiln-type was not provided.

Table 4-2.3. NO_x Emissions with 3 Channel and Rotaflam[®] Low-NO_x Burners

Kiln	With 3 Channel Burner (ppm)	With Rotaflam [®] Burner (ppm)	Percent Reduction (%)
A	774	409	47
B	865	664	23
C	484	350	28
D	487	336	31

Emissions data are also available before and after a Rotaflam[®] low-NO_x burner was installed on a long-wet kiln (see Table 4-2.4). (53) The average emissions decreased 14 percent.

Table 4-2.4. Emissions Before and After Installation of a Rotaflam[®] Burner on a Wet Kiln

Year	Average Emissions (lb. NO _x /tonne clinker)	Percent Reduction ^a (%)
1990	277	-
1992 ^b	288	-
1993	269	-
1994	275	-
1995 (Rotaflam [®] installed)	239	14

^a Percent reduction is relative to the 1990, 1992-1994 average NO_x emissions, 277.25 lb. NO_x/hr.

^b 1991 data were not provided.

The Fuller Company low NO_x In-Line Calciner was installed in an RMC Lonestar kiln, which reported 30-40 percent reductions in the amount of thermally formed NO_x after installation. (54)

In January 2000, the PCA provided results of a survey of cement facilities where the respondents indicated 14% of the operating U.S. kilns (22 kilns) have already installed a low-NO_x burner (81% of the facilities representing 81% of the operating U.S. kilns responded to the survey). The remaining 139 kilns that are represented by the survey have not installed low- NO_x burners. (55,56)

4.2.4 Staged Combustion of Fuel

In conventional long (wet or dry) rotary kilns, all heat required for the cement-making process is supplied in the primary kiln burning zone, where the combustion occurs at the hottest temperature in the kiln. In the cement-making process, the preheating and calcination of the raw materials requires a large amount of heat but are typically at a temperature of 600 to 900°C (1,100 to 1,650 °F) which is much lower than the kiln's clinker-burning temperature of 1,200 to 1480 °C (2,200 to 2,700 °F). (57) In the secondary combustion method, part of the fuel is burned at a much lower temperature in a secondary firing zone to complete the preheating and calcination of the raw materials.

4.2.5 Preheater/Precalciner and Tire Derived Fuel

This concept of a secondary firing zone is the basis of the preheater/precalciner cement kiln design. Almost all new cement kilns have a preheater/precalciner-type design. In the preheater kilns, the primary emphasis is on efficient heat recovery from kiln exhaust gases (see Figure 4-4.1). (58) However, up to 15 to 20 percent of the fuel may be fired in the riser duct in preheater designs. (58)

Precalciner systems typically employ a tower of four-stage cyclones for efficient gas-solids contact, which improves the energy efficiency of the overall process (see Figure 4-4.2).

(58) In a typical precalciner kiln almost 40 to 50 percent of the fuel is burned at a lower (calcination) temperature which reduces the thermal NO_x formation considerably.

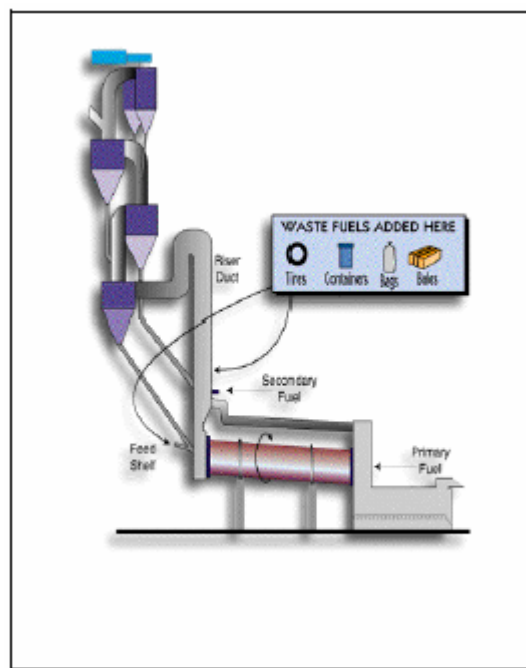
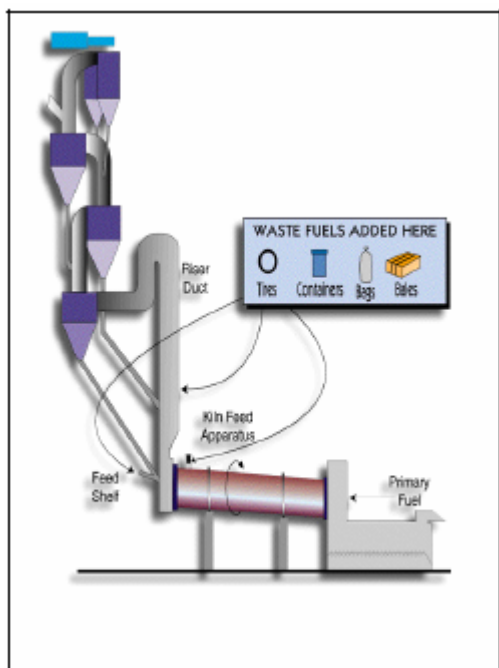


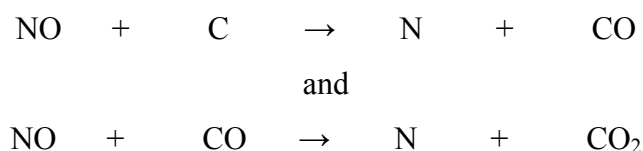
Figure 4-2.1. Schematic of Preheater (58) Figure 4-2.2. Schematic of Precalciner(58)

Tire-derived fuel can also be added to the feed end of a preheater or precalciner kiln. The Mitsubishi Cement Company's Cushenbury Plant in Lucerne Valley, CA began using whole waste tires as a fuel supplement in 1993. The waste tires are delivered in enclosed container trucks and dumped into the plant's automated handling system. A live bottom hopper and singulator place the waste tires on a conveyor system. This conveyor system transports the tires to the feed end of the kiln and drops the tire into an airlock system that allows the waste tire to fall onto the feed plate inside the kiln at a rate of five to six tires per minute.

Currently, 8,000 to 9,000 tires are burned per day, totaling about 13 percent of the fuel. Tires have a fuel content of approximately 14,000 Btu/lb. and a sulfur content that is roughly the same as the coal that would be used. The steel belting in the waste tires supplements the iron requirements and approximately two percent of the iron in the final product comes from the tires. The addition of waste tires reduces NO_x emissions from the kiln by 30 to 40 percent, and there is no significant change in toxic, hydrocarbon, or metal emissions. (59,60,61)

4.2.6 Low- NO_x Precalciners

Most of the major cement kiln suppliers are now offering “low NO_x” precalciner designs for new kilns. These designs typically inject a portion of the fuel into the feed end of the kiln, countercurrent to the exhaust gas flow.(62) This fuel is burned in a substoichiometric O₂ environment to create a strongly reducing atmosphere (relatively high concentrations of CO) by following the simplified reactions:



This reducing atmosphere inhibits the formation of fuel NO_x and destroys a portion of the NO_x formed in the kiln burning zone. In some designs, additional fuel is then added, again with insufficient O₂ for complete combustion, to create another reducing zone. Several precalciner kilns in the US have recently been retrofitted with these “low NO_x” precalciners and preliminary information indicates a noticeable reduction in NO_x per ton of clinker. (33) Up to 46 percent reduction of NO_x emissions has been reported without causing excessive coating difficulties in the kiln. (62)

Nitrogen present in the fuel may also participate in the reduction of NO_x. The primary NO_x formation mechanism in the secondary firing is the fuel NO_x formation that depends upon the nitrogen content of the fuel used. In order for the above reactions to proceed at reasonable rates the temperature in the reduction zone should be maintained between 1000 and 1200°C (1830 to 2190°F). These temperatures may lead to coating difficulties, particularly if the fuel used is coal with high ash content. (63)

It is not possible to use “staged combustion” on preheater kilns that are firing fuel in the riser since in staged combustion it is necessary to add the fuel in an oxygen deficient atmosphere and then supply additional combustion air to fully combust the fuel. Preheater kilns do not have tertiary air ducts to supply the additional combustion air. The air for combustion of the

secondary fuel must come through the kiln, which precludes introducing the secondary fuel into an atmosphere with insufficient oxygen for complete combustion. (33)

Emissions reductions have also been found when tire derived fuel was burned in a precalciner. In one case, when 47 percent of the coal fired in the calciner was substituted with tire-derived-fuel, a reduction in NO_x emissions of about 29 percent was observed. (64)

4.2.7 Mid-Kiln Firing

The concept of staged combustion of fuels may also be used in conventional wet and long-dry kilns by injecting solid fuel into the calcining zone of a rotating long kiln using a specially designed feed injection mechanism. (65) This system is known as mid-kiln firing (MKF) and allows part of the fuel to be burned at a material calcination temperature of 600 to 900°C (1100 to 1650°F) which is much lower than the clinker burning temperature of 1200 to 1480°C (2200 to 2700°F). (57)

To maintain continuity in the heat input, solid and slow burning fuels (such as tires) are most amenable for MKF. The Cadence feed fork MKF technology was first introduced in 1989. It can be installed during an annual maintenance shutdown. It is comprised of three primary components: (1) a staging arm or ‘feed fork’ that picks up the fuel modules and positions them for entry into the kiln, (2) two pivoting doors that open to allow the fuel modules to drop into the kiln, and (3) a drop tube that extends through the side wall of the kiln. In addition to these basic components, feed fork technology also requires a delivery system, which positions the fuel modules so they can be picked up by the feed fork and a mechanism for opening the doors so the fuel modules can enter the kiln. (66) Due to the rotation of the kiln, fuel can be conveniently injected only once per revolution from the top.

Although most feed forks today are dedicated to whole tires, one facility uses baled industrial waste as a fuel, and many others are investigating a variety of energy containing waste materials from carpet scrap to pharmaceutical waste. These energy-bearing waste materials can be containerized or dimensionalized into discrete fuel modules to be fed to the kiln using the feed fork. (66)

Inserting whole tires into mid-kiln locations can give precalciner stability to the kiln. The operators have two points of control to assist in stabilizing kiln operation. Tires burn for 15 to 20 minutes within the kiln after entry. This is deduced from observations of the rate of change in kiln exit oxygen levels after entry of tires begins. With proper instrumentation, control of the kiln can be improved by adding solid fuels midkiln. (67)

Mid-kiln firing of tires or other waste-derived fuels does not reduce the final product quality; in fact, many of Cadence's cement kiln partners have reported an improvement in the clinker burnability and mineralogy. The enhanced control has shown to impart better formation of clinker. Reductions in cement fineness have been shown while maintaining similar seven-day strengths. Several facilities also have reported an extended life of the refractory in the burn zone. (66,67)

By adding fuel in the main flame at mid-kiln, MKF changes both the flame temperature and flame length. These changes may reduce thermal NO_x formation by burning part of the fuel at a lower temperature and by creating reducing conditions at the solid waste injection point, which may destroy some of the NO_x , formed upstream in the kiln burning zone. MKF may also produce additional fuel NO_x depending upon the nitrogen content of the fuel. (68) However, as discussed in section 5.1.3, fuel NO_x is unimportant relative to thermal NO_x formation. Additionally the discontinuous fuel feed from MFK can result in increased CO emissions especially if hazardous wastes are used. To control CO emissions, the kiln may have to have increased combustion air, which can decrease production capacity. (69)

According to literature from Cadence, in tests of its feed fork technology, one kiln reduced NO_x emissions by 38%, overall particulate emissions by 14%, metal emissions by 30%, SO_2 emissions by 36%, and net emissions of all hydrocarbons by 29%. (66,67) In the research conducted for this report, test data were compiled for seven dry kilns and three wet kilns with MKF technology. In nine tests on the dry kilns, the average reduction in NO_x emissions was 33%, with a range from 11% to 55%. In three tests on the wet kilns, the average reduction in NO_x emissions was 40%, with a range from 28% to 59% (see Table 4-8). (69,70,71,72,73) It

should be noted that the three kilns that are known to have CEMS all reported emissions reductions of 45 percent or more.

Table 4-2.5. Emissions From Kilns With Mid-Kiln Firing

	Emissions (lb. NO_x/tonne clinker)	Percent Reduction (%)	Emissions Based on CEMS Data
Dry Kilns^a			
A ⁴⁰	not given	13.6	unknown
B ⁴⁰	not given	11.1	unknown
C ^{24,44}	not given	45.1	yes
C ⁴⁰	not given	55.3	yes
D ^{21,41}	2.7	not given	unknown
E ^{22,42}	10.2	13.9	unknown
F ⁴⁰	not given	46.6	unknown
F ⁴⁰	not given	50.4	unknown
F ⁴⁰	not given	28.3	unknown
Average (Dry Kilns)	6.4	33.3	
Wet Kilns			
G ^{23,43}	not given	59.0	yes
H ⁴⁰	not given	35.0	unknown
I ⁴⁰	not given	27.6	unknown
Average (Wet Kilns)	n/a	40.5	
Average (Dry & Wet Kilns)	6.4	35.1	

^a There was more than one test at some kilns.

Waste-derived fuels with high heating values represent an economical source of energy for the cement industry and its consumption has been increasing during the past decade.¹² Midkiln firing is a proven technology and so far at least 21 long kilns in the U.S. and nearly 40 kilns worldwide have been modified to allow mid-kiln firing of solid and hazardous waste. (66,74)

4.3 Lower Temperature Oxidation Based Technologies

Oxidation technologies were not evaluated in the EPA 2000 Report. One of these technologies, LoTOxTM, is currently being installed in refineries at fluidized catalytic cracking units (FCCUs). The temperatures, gas flow rates and other characteristics of FCCUs are similar

enough to cement plants that these technologies should be considered as candidates for evaluation as transferable technologies to application at cement kilns.

4.3.1 Introduction

Oxidation technologies for flue gas NO_x control developed in recent years have become commercially successful and economically viable as an alternative to ammonia and urea based technologies using reduction chemistry to remove NO_x. Commercially available technologies such as Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), which reduce NO_x to nitrogen using ammonia or urea as an active chemical are optimized to specific temperature windows and have similar reagent costs for the varying ammonia based reagents. Oxidation technologies can work in other temperature regimes and use different reagents that are not linked to ammonia costs and, thereby, provide important control options to ammonia-based NO_x reduction technologies.

Oxidation technologies convert lower nitrogen oxides such as nitric oxide (NO) and nitrogen dioxide (NO₂) to higher nitrogen oxides such as nitrogen sesquioxide (N₂O₃) and nitrogen pentoxide (N₂O₅). These higher nitrogen oxides are highly water soluble and are efficiently scrubbed out with water as nitric and nitrous acids or with caustic solution as nitrite or nitrate salts. NO_x removal in excess of 90% has been achieved using oxidation technology on NO_x sources with high sulfur content, acid gases, high particulates and processes with highly variable load conditions. Generally these technologies work at relatively low temperatures (100-950°F) and some of these technologies are likely most cost effective for use on plants with existing scrubbers. But may also prove to be cost effective options due to their potential application in lower temperature windows which can avoid expensive options like gas reheat. These technologies are used for NO_x control for a variety of NO_x emission sources but are not known to have been used to date on a cement kiln.

4.3.2 LoTOxTM

General description. The LoTOxTM System uses ozone as the oxidizing agent, which selectively oxidizes relatively insoluble NO_x to higher oxides of nitrogen. These higher oxides

are readily soluble and easily removed in a wet scrubber. The patented system, which can be installed as a stand-alone or retrofit design, provides sufficient residence time under maximum load conditions to allow complete reaction of the ozone. The system's small and adaptable footprint, as well as its ability to produce ozone on demand, provides control of the installation to maximize NO_x control and minimize capital and operating costs. The LoTOx™ System is very selective for NO_x removal, oxidizing only the NO_x and therefore efficiently using the treatment chemical, ozone, without causing any significant SO_x oxidation and without affecting the performance of the downstream SO_x scrubber.

Figure 4-3.1. is an overall process diagram of the LoTOx™ System.

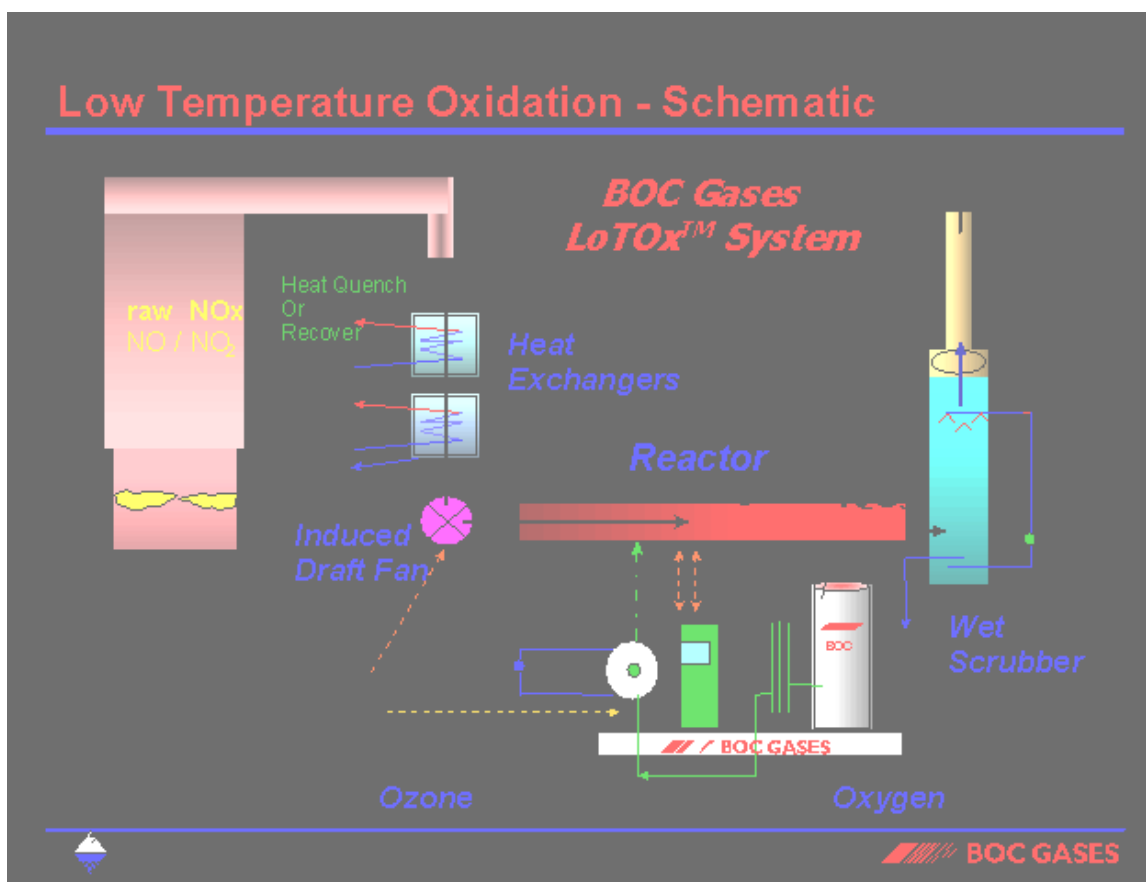


Figure 4-3.1. Overall Process Diagram of the LoTOx™ System

Figure 4-3.2. provides another example of a LoTOx™ system where the ozone injection is included in the scrubber.

EDV[®] Wet Scrubbing System With LoTOx[™] injection

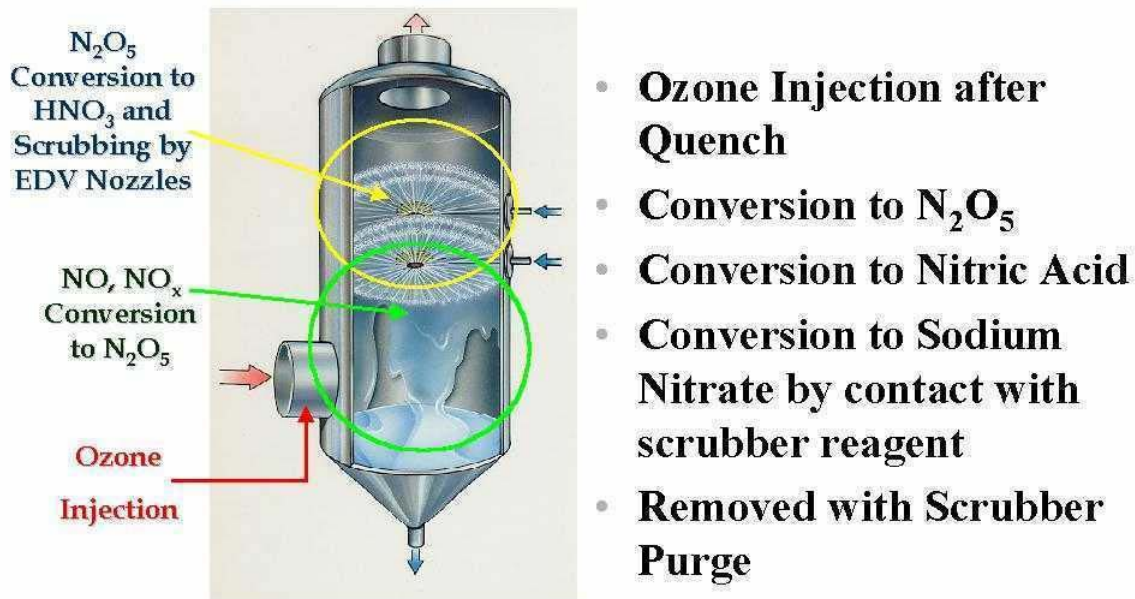


Figure 4-3.2. EDV Wet Scrubbing System with LoTOx[™] Injection

Potential applicability. The large gas volumes, high moisture levels and large quantities of dilution air needed to reach the operating temperature range in some systems may limit the applicability of the LoTOx[™] system.

Advantages. Table 4-3.1 provides an overview comparing the LoTOx[™] process with SNCR and SCR technologies.

Table 4-3.1. Comparison Of Common Post Combustion NO_x Abatement Technologies For NO_x Emissions Control

	SNCR	SCR	LoTOx™
Mode of Treatment	Reduction	Reduction	Oxidation
Active Chemical	NH ₃ / Urea	NH ₃ / Urea	Ozone
Gas Temperature Required °F	1650 - 2000	500 - 900	150 – 250
Pressure Required, psig	0+	0++	0+
Placement in Exhaust System	Near Combustion Chamber	Between Air Pre-Heater and Economizer (boiler)	Tail End
Catalyst Bed	No	Yes	No
Gas Phase Reaction Duct	Yes	No	Yes
Scrubber	Optional	Optional	Yes
NO _x Reduction Achieved	40 - 70 Percent	60 - 95 Percent	90 - 95 Percent
Slip of Active Agent	NH ₃ – Yes	NH ₃ - Yes	Ozone - No
CO Emissions After Treatment	May Increase	May Increase	No Effect
SO _x Emissions After Treatment	Little Effect – Maybe H ₂ S	Little Effect - Maybe H ₂ S	No Effect or Significantly Reduced
Gas Temperature Outside Operating Range - Overshoot	More NO _x Emissions Through NH ₃ Oxidation	More NO _x Emissions Through NH ₃ Oxidation, Ammonia Slip	Increased O ₃ Consumption for the Time Period of Overshoot
Gas Temperature Outside Operating Range - Undershoot	More NO _x Emissions Through Reduced Reduction by NH ₃	More NO _x Emissions Through Reduced Reduction by NH ₃ , Ammonia Slip	No Effect

An additional advantage is the control of SO_x emissions that would likely be achieved if the LoTOx™ system were added to any system that currently does not have a wet scrubber if joint control of SO_x and NO_x is required. Lower cost spray towers that do not appreciably control SO_x can be installed at lower cost than flue gas desulfurization scrubbers. The cost models for application of LoTOx™ at wet kilns are based on installing simple spray towers that do not control SO_x.

Disadvantages. It is likely that for most applications, the LoTOx™ option would be an add-on to existing APCD systems. Because of high electrical power usage, costs are reported to be high. Electricity and oxygen costs alone are estimated to be greater than \$1,600/ton of NO_x controlled.

Additional nitrate captured in the existing sulfate scrubber could impact the quality of the plant's artificial gypsum although, with a typical dewatering system, this should not be a problem because of the much higher solubility of the nitrates relative to sulfates. High nitrate wastewater could be used by local farmers as fertilizer or could be used at the plant to fertilize grass areas as well as water/fertilize in quarry reclamation areas. Lowering the exit gas temperature and adding moisture may result in problems with condensation in the stack.

Emissions performance. There are three primary process variables which impact the NO_x control capabilities of the LoTOxTM process: temperature of the flue gas (T), residence time of the flue gas in the reactor duct (RT) and amount of ozone (O₃ Factor) injected into the reactor duct. Based on the results of LoTOxTM demonstration testing, the most efficient control parameters for a full scale system on the Quemetco, Inc., furnace are a temperature of 175 °F or less, a residence time of four seconds, and an ozone injection factor of 80 to 90. The O₃ Factor represents the O₃ to NO_x ratio at the inlet to the reaction duct. The presented data uses O₃ Factor for the sake of clarity and to provide meaningful data while maintaining confidentiality of proprietary intellectual information. Figure 4-3.3. depicts the performance conditions of the LoTOxTM process for the design conditions of RT = 4 seconds, T = 175 °F and O₃ Factor = 70 to 90. Under these design conditions the NO_x removal achieved ranges from 80 percent at an O₃ Factor of 70 to 95 percent at an O₃ Factor of 90.

This technology should be considered transferable in nature. It has not been used on a cement kiln but it has been used on similar large sources. Discussions with this technology's vendors reveals that existing SO_x and CO levels at the cement plants in Midlothian should not be a factor in the use of this technology. Applications or tests have already been performed at CO and SO_x levels well above those seen in any of these cement plants.

Ideal Operating Conditions for NO_x Removal from 80% to 95%

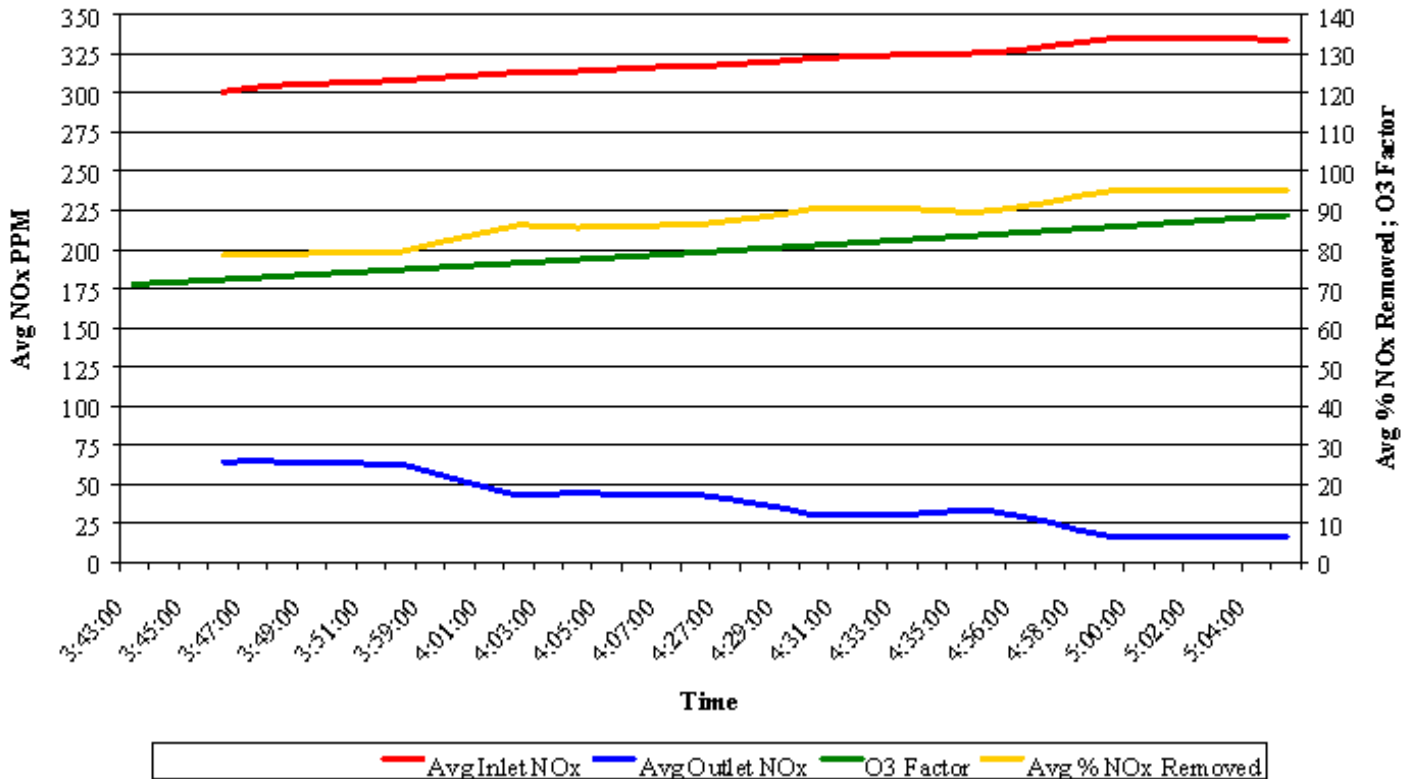


Figure 4-3.3. Ideal Operating Conditions for NO_x Removal from 80% to 95%

Cost. Ohio Coal Development Office (OCDO) provided 65 percent of the capital to install a \$6.3 million LoTOxTM unit at the Medical College of Ohio. The project includes two processes: LoTOxTM for NO_x and particulate material control and Rapid Absorption Process (RAP, another BOC licensed process) for sulfur dioxide control. The controls are for 25 megawatt capacity boilers burning Ohio coal containing 3 percent sulfur. According to the BOC Company literature, the unit is designed to remove about 90 percent of the NO_x in emission gases. The RAP process uses a slurry of lime injected into the flue gas to capture SO₂ and a fabric filter (baghouse) to remove the calcium sulfate particles. Cost effectiveness has been estimated to be in the range of \$1,700 to \$1,950 per ton NO_x removed. (54)

In June 2001, BOC announced that they had installed, started up and commissioned a LoTOxTM unit at J & L Specialty Steel's Midland, PA plant. Details of the installation are not

published in any detail. However, Robert Ferrell, BOC Vice President of Business Development, said, “We were able to modify the system to achieve a higher level of control than was originally anticipated. We have been able to reduce NO_x emissions by more than 95 percent.” No costs or capacity numbers were available.

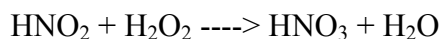
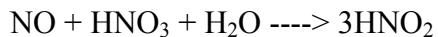
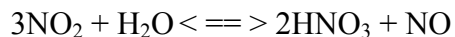
A subsequent search of EPA’s RBLC27 Database indicates that at least two other plants in the U.S. are using (or are planning to use) BOC’s LoTOxTM process in their facilities. These plants are Lion Oil Company in El Dorado, AR and Marathon-Ashland Oil in Texas City, TX. Both plants use (or will use) the LoTOxTM on their Fluidized-Bed Catalytic Cracking Units (FCCU) for NO_x control. Operating conditions and performance results are not available.

Another article, written by a BOC employee, stated, “The capital (recovery) and operating costs for the (LoTOxTM) system have been evaluated for various system sizes and (they) fall well within the costs per ton of NO_x removed typical for post-combustion treatment technologies in non-utility applications.” Unfortunately, this information is not very helpful for determining cost for the cement industry since a paper published by NESCAUM gives the cost effectiveness range for NO_x removal from \$390 to \$5,450 per ton NO_x. Cost effectiveness is heavily dependent on each individual facility’s situation. This includes their existing control equipment, extent of modifications necessary to install new control equipment, and the degree of DRE required to achieve the desired results.

Based on the data available, capital costs for adding LoTOxTM to a system that does not have a wet scrubber such as the wet kilns in Midlothian are likely to be much more costly than the kilns that already have wet scrubbers. Vendor information was used to calculate costs associated with the application of LoTOxTM to the cement plants in Midlothian. Estimated costs associated with the precalciner kilns which already have scrubber systems in place are \$2,300-\$2,600/ton of NO_x controlled. Estimated costs associated with the wet kilns which do not have scrubber systems in place are \$3,000-\$3,700/ton of NO_x controlled. The costs for the wet kilns include installation of a spray tower to remove the soluble NO_x oxidation products produced by the LoTOxTM system. (74a, 74b, 74c, 74d, 74e, 74f, 74g, 74h, 74i, 74j, 74k, 74l, 74m, 74n)

4.3.3 Hydrogen Peroxide

General description. There are several methods for controlling NO_x emissions. Gas scrubbing is one of the most common forms of NO_x treatment, with sodium hydroxide being the conventional scrubbing medium. However, the absorbed NO_x is converted to nitrite and nitrate, which may present wastewater disposal problems. Scrubbing solutions containing hydrogen peroxide are also effective at removing NO_x, and can afford benefits not available with NaOH. For example, H₂O₂ adds no contaminants to the scrubbing solution and so allows commercial products to be recovered from the process, e.g., nitric acid or nitrate salts (for use as fertilizer). In its simplest application, H₂O₂ (0.5-1 wt.%) and nitric acid (35-45 wt.%) are used to scrub both nitric oxide (NO) and nitrogen dioxide (NO₂) -- the chief components of NO_x from many industrial sources. The reactions are rapid at moderate temperatures (30-80 °C), with about 1.7 and 0.37 lb. H₂O₂ required per lb. NO and NO₂, respectively. The chemistry controlling the process is outlined below:



There are several other processes that also use hydrogen peroxide to remove NO_x. The Kanto Denka process employs a scrubbing solution containing 0.2% hydrogen peroxide and 10% nitric acid while the Nikon process uses a 10% sodium hydroxide solution containing 3.5% hydrogen peroxide. A fourth process, the Ozawa process, scrubs NO_x by spraying a hydrogen peroxide solution into the exhaust gas stream. The liquid is then separated from the gas stream, and the nitric acid formed is neutralized with potassium hydroxide. The excess potassium nitrate is crystallized out, and the solution reused after recharging with hydrogen. In addition to the methods cited above in which NO_x is oxidized to nitric acid or nitrate salts, a series of Japanese patents describe processes and equipment for reducing NO_x to nitrogen using hydrogen peroxide and ammonia. The processes are efficient but must be carried out at higher temperatures than the processes cited earlier.

The injection of hydrogen peroxide (H_2O_2) into hot flue gases to prevent emissions of nitrogen oxides (NO_x) has been demonstrated at the pilot scale at a boiler at Kennedy Space Center (KSC). That project was an outgrowth of research funded by the Gulf Coast Hazardous Substance Research Center from the years 1993-1996. The H_2O_2 is injected into hot boiler flue gases to oxidize the NO into NO_2 , HNO_2 and HNO_3 , which can then be removed in a wet or dry scrubber (see Figure 4-3.4). (74o)

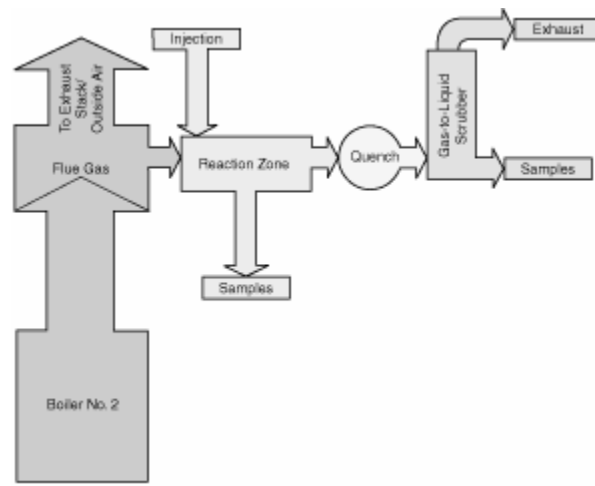
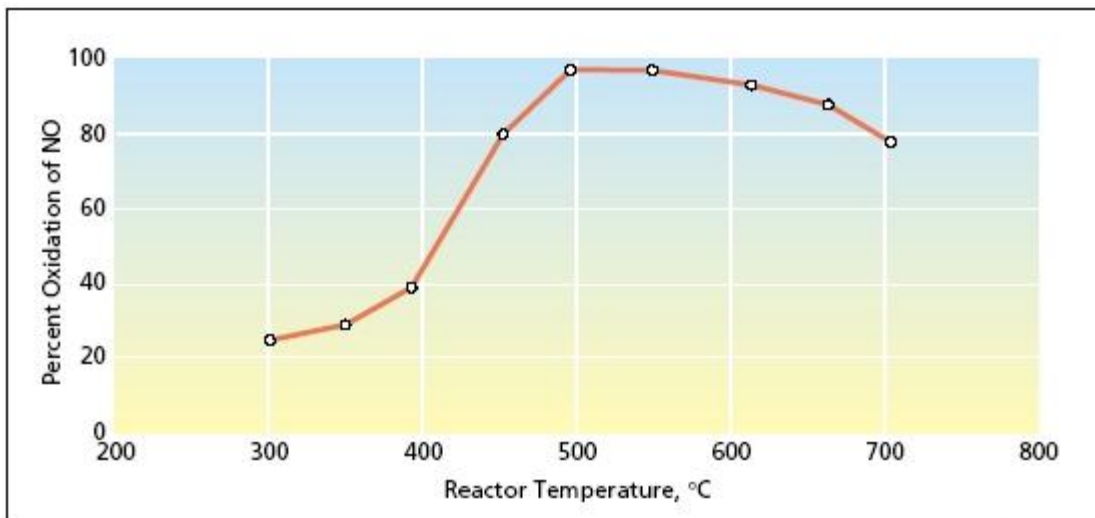


Figure 4-3.4. Conceptual Design of Hydrogen Peroxide NO_x Control System

In one of several sets of experiments to demonstrate the feasibility of the method, the optimum temperature for conversion of NO to HNO_2 , HNO_3 , and NO_2 by use of injected H_2O_2 was found to be about 500 °C (see Figure 4-3.5).

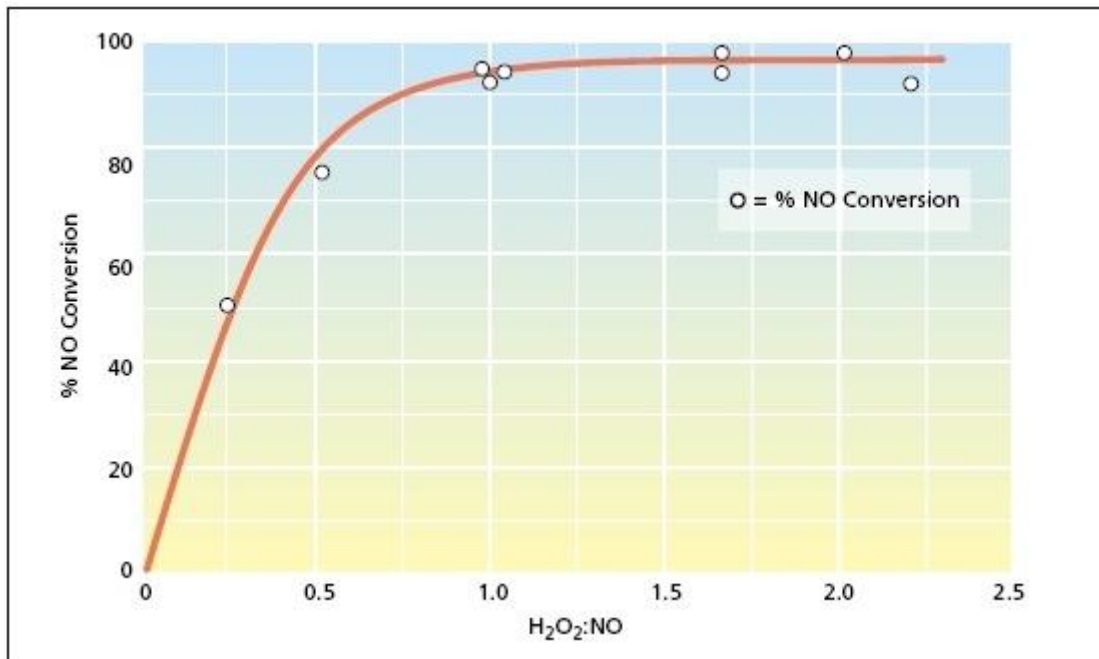


The conversion of NO by oxidation to other species was measured as a function of reactor temperature. The reactor inlet conditions for the points shown here were 400 ppm NO and 400 ppm H₂O₂ for a molar ratio of 1:1.

Figure 4-3.5. Effect of Temperature on Peroxide Oxidation of NO

In a study performed under guidelines of the EPA, EPRI compared the economics of SCR and the experimental H₂O₂-injection/scrubbing method for a design base case and a variety of alternative cases. This study illustrated the tradeoff between capital and operating costs for the two methods. The single largest factor in determining the total cost of one method relative to the other method was found to be the H₂O₂:NO molar ratio. At the H₂O₂:NO molar ratio of 1.92, which was previously demonstrated in the laboratory, the H₂O₂-injection/scrubbing method was shown to be uneconomical. However, it was also concluded that the molar ratio in a full-size coal-fired power plant could be lower than that found in the laboratory, and that on the basis of all the assumptions of the study, at an H₂O₂:NO molar ratio of 1.37, the H₂O₂ injection/scrubbing method could be an economically feasible alternative to SCR.

Pilot-scale tests run at Kennedy Space Center demonstrated the feasibility and competitiveness of this new technology. The H₂O₂ to NO molar ratio, at 500 °C shown to achieve a NO conversion efficiency of greater than 90 percent was 1:1, which is significantly lower than the required 1.37:1 (See Figure 4-3.6). (741)



The outlet concentration of the O was significantly reduced when the H₂O₂ was injected. At 500 °C, 400 ppm NO, and various inlet concentrations of H₂O₂ (represented as the molar ratios), 90 percent conversion of NO was achieved at the reactor outlet for a molar ratio of 1:1.

Figure 4-3.6. Effect of Molar Ratio on Peroxide Oxidation of NO

Potential applicability. This option is a solution that may have particular applicability to kilns with existing scrubber systems. Data suggests it may work over a wide range of temperatures depending on the specific version of this technology that is implemented. For the high temperature version of this process, injection of the hydrogen peroxide into the upper portion of the preheater tower of a precalciner kiln at the appropriate temperature may be possible.

Advantages. The biggest advantage of this technology may be a relatively low capital investment for plants with existing scrubbers. An additional advantage is that there are indications that hydrogen peroxide based scrubbers may also enhance SO_x scrubbing and may lower hydrocarbon emission depending on the operating temperature, reagent system and retention time of the system.

An additional advantage of this technology is that it operates in a unique temperature window that is slightly below the temperatures commonly used for SCR. The optimal technology for any specific cement kiln process may be the technology that installs best in the

existing temperature windows of the process with the least potential adverse impact on downstream processes and equipment. Prices of ammonia-based reagents fluctuate with natural gas prices and are currently relatively high. Cement plants may elect to use more than one NO_x control technology to take advantage of changes in the market for reagents. Hydrogen peroxide currently appears to be a more cost effective reagent than ammonia-based reagents.

Disadvantages. For plants without scrubbers, add on systems are required. An additional factor is that the cost of hydrogen peroxide has risen significantly in recent years with increased natural gas prices and fluctuating supplies. Hydrogen peroxide has become a major commodity chemical as a bleaching agent for paper production free of chlorine. Recent production capacity increases appear to be stabilizing prices.

Additional nitrate captured in the existing sulfate scrubber could impact the quality of the plant's artificial gypsum although, with a typical dewatering system, this should not be a problem because of the much higher solubility of the nitrates relative to sulfates. High nitrate wastewater could be used by local farmers as fertilizer or could be used at the plant to fertilize grass areas as well as water/fertilize in quarry reclamation areas.

Emissions performance. At 500 °C and with a molar ratio of 1:1 H₂O₂/NO_x removal efficiencies of greater than 80% appear to be achievable. Scrubber efficiency data for the wet low temperature process was not available. Either of these technologies should be considered investigative in nature. Application of this technology would clearly be an innovative approach that does not have a history of commercial application compared to SCR, SNCR or LoTOxTM. Testing in a cement plant application would clearly be required to determine performance and process impacts.

Cost. Assuming a cost of \$0.50/lb. of hydrogen peroxide the reagent cost would be approximately \$739/ton of NO₂ removed (depending on the existing oxidation state of the NO in the system). This might be offset to some extent by the sale of solutions of nitrate salts as fertilizer. This cost appears to be favorable relative to the electrical and oxygen costs of the LoTOxTM that exceed \$1,600/ton of NO_x controlled. It is also favorable to the current ammonia cost of about \$1,200/ton of NO_x controlled using SNCR.

4.3.4 OXONE (Dupont – potassium monopersulfate)

General description. Scrubbing with strong aqueous oxidants promises to be less expensive than competing post-combustion methods for NO_x removal such as selective catalytic reduction (SCR) and thermal NO_x removal. The goal of a project by Yusuf G. Adewuyi at North Carolina A&T State University is to develop an innovative and cost-effective aqueous scrubber for the simultaneous removal and destruction of oxides using strong oxidizing agents such as oxone. Oxone (2KHSO₅·KHSO₄·K₂SO₄) is a triple salt of potassium and may be regarded as a mono-substituted derivative of hydrogen peroxide. However, it has an oxidation potential greater than that of hydrogen peroxide ($E \text{ HSO}_5^-/\text{HSO}_4^- = 1.82 \text{ eV}$ compared to $E \text{ H}_2\text{O}_2/\text{H}_2\text{O} = 1.77 \text{ eV}$). The aqueous absorption and kinetics of oxidation of nitrogen oxides (NO_x) and SO₂ by OXONE in a bubble column operated as batch or continuous OXONE was presented at an AIChE meeting in October of 2005. Table 4-3.2 provides a breakdown of the chemical constituents of the Oxone reagent. (74p)

Table 4-3.2. Oxone Constituents

Material	CAS Number	%
"Oxone" Monopersulfate Compound	70693-62-8	
Potassium Peroxymonosulphate	10058-23-8	34-43
Potassium Bisulfate	7646-93-7	18-23
Potassium Sulfate	7778-80-5	23-29
Potassium Peroxydisulfate	7727-21-1	2-3
Sodium Carbonate	497-19-8	0-20
Magnesium Carbonate	546-93-0	1-2

Potential applicability. Applicability is similar to the wet low temperature hydrogen peroxide option.

Advantages. Advantages are similar to the hydrogen peroxide option. Costs may be lower.

Disadvantages. This is an experimental technology. Additional nitrate captured in the existing sulfate scrubber could impact the quality of the plant's artificial gypsum although with a typical dewatering system this should not be a problem because of the much higher solubility of the nitrates relative to sulfates. High nitrate wastewater could be used by local farmers as fertilizer or could be used at the plant to fertilize grass areas as well as water/fertilize in quarry reclamation areas.

Emissions performance. As an experimental technology performance is not clear but is likely to be similar to the hydrogen peroxide technology. This technology should be considered investigative in nature.

Cost. Oxone is a commercial product manufactured by Dupont. Inquiries to Dupont about cost have not been responded to at this time.

4.3.5 Sodium Acetate Process

General description. This process involves absorption and subsequent reaction of NO_x in the aqueous phase. Direct absorption involves a reaction chain that achieves both SO_x and NO_x removal. One form involves an SO_2 reaction step, a subsequent NO reaction, and a termination step that produces gypsum. Table 4-3.3 shows the different steps involved in the process.

Table 4-3.3. Reaction Steps and Pathway Equations for the Sodium Acetate Direct Absorption Process For Simultaneous NO_x And SO_x Removal (OECD, 1983).

Absorption and Gypsum Formation
Absorption $\text{SO}_2 + 2\text{CH}_3\text{COONa} + \text{H}_2\text{O} \rightarrow \text{Na}_2\text{SO}_3 + 2\text{CH}_3\text{COOH}$ $2\text{NO} + 5\text{Na}_2\text{SO}_3 + 4\text{CH}_3\text{COOH} \rightarrow 2\text{NH}(\text{NaSO}_3)_2 + \text{Na}_2\text{SO}_4 + 4\text{CH}_3\text{COONa} + \text{H}_2\text{O}$
Gypsum formation $\text{Na}_2\text{SO}_4 + \text{Ca}(\text{OH})_2 + 2\text{CH}_3\text{COOH} \rightarrow \text{CaSO}_4 \cdot 2\text{H}_2\text{O} + 2\text{CH}_3\text{COONa}$
Imide Treatment Step
Hydrolysis $\text{NH}(\text{NaSO}_3)_2 + 2\text{H}_2\text{O} \rightarrow \text{NH}_4\text{HSO}_4 + \text{Na}_2\text{SO}_4$ Release of NH ₃ $\text{NH}_4\text{HSO}_4 + \text{Ca}(\text{OH})_2 \rightarrow \text{NH}_3 + \text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ Nitrogen gas formation $4\text{NH}_3 + 3\text{O}_2 \rightarrow 2\text{N}_2 + 6\text{H}_2\text{O}$

Potential applicability. Applicability is likely to be similar to the wet low temperature hydrogen peroxide process.

Advantages. The advantage of this process is its ability to eliminate gaseous NO_x and SO_x simultaneously. For plants with existing SO_x scrubbers the application may be as simple as adding selected reagents to the recirculating scrubber solution and subsequent scrubber treatment tanks. For plants with cooling towers the option of adding the reagents to the cooling tower water feed may be functional.

Disadvantages. SO_x is required in adequate quantities to maintain the chain-reaction mechanism. Also, this process turns an air-pollution problem into a wastewater problem. Additional nitrate captured in the existing sulfate scrubber could impact the quality of the plant's artificial gypsum although with a typical dewatering system this should not be a problem because of the much higher solubility of the nitrates relative to sulfates. High nitrate wastewater could be used by local farmers as fertilizer or could be used at the plant to fertilize grass areas as well as water/fertilize in quarry reclamation areas.

Emissions performance. Unknown. Data for application of this technology to cement kilns and similar emission sources was not found in the literature. This technology should be considered investigative in nature.

Cost. Costs are not clear at this time but may be lower than the hydrogen peroxide option.

4.3.6 Potential Applicability of Oxidation Technology to Ash Grove Plant

General Discussion. The Ash Grove plant has three wet process kilns without any existing wet scrubber system. That would require them to place a complete oxidation system in place as an add-on technology including the scrubber or alternatively just a spray tower after the existing ESPs. Assuming that all of the available options would have a similar capital cost for a spray tower/scrubber system careful evaluation of the alternative reagent systems is warranted.

A trial system for evaluating the reagent systems may be warranted. As an example, three one-month trials using alternative reagents in a skid-mounted scrubber could be performed prior to scaling up to a full system. It may be possible to combine the gas flows from the three kiln systems into a single flow to minimize the cost of the scrubber system.

Because of the high moisture levels in the gasses from wet kilns it may be necessary to bypass a portion of the stack gasses around the spray tower/scrubber for use as reheat gas after the spray tower/scrubber to prevent condensation problems in the stack. To the extent that such a strategy is required the efficiency of the NO_x removal would be proportionately impacted.

Conclusions. SCR at the Ellis County wet kilns would require reheat of the exhaust gas. This suggests that further investigation of the oxidation technologies is likely to be a cost effective option. As these technologies would require a scrubber, consideration of the benefits of control of sulfur oxides should also be considered in evaluating scrubber options. The cost modeling for oxidation technologies is based on a simple spray tower that does not control sulfur oxides. However, additional air quality benefits, including reduction in fine PM precursors would occur should a source choose to install flue gas desulfurization. A combination of midkiln

combustion, midkiln SNCR and a low temperature oxidation technology may provide exceptional NO_x control at the most effective aggregate cost per ton of NO_x controlled for wet kilns.

4.3.7 Potential Applicability of Oxidation Technology to Holcim Plant

General Discussion. The Holcim Plant has two large precalciner kiln systems with existing scrubbers. An oxidative control technology for these kiln lines has significant potential to provide NO_x control using the existing scrubber system.

A variety of low temperature oxidation reagent systems could be tested for efficiency in the existing wet scrubber system. It should also be relatively simple to set up a temporary system to test the high temperature hydrogen peroxide control option in a manner similar to the set up that was used to test SNCR. The critical factor in the successful use of the high temperature hydrogen peroxide control technology will be determining the best location for injection. Careful gas phase temperature measurements and modeling should help determine the optimum location.

Conclusions. It may be possible to add a hydrogen peroxide injection system to the preheater tower at the correct location with a relatively low capital expenditure. By combining SNCR and the high temperature hydrogen peroxide system, an effective control system could be put in place at a minimal capital expenditure that would then allow the plant to use more or less of the hydrogen peroxide and ammonia reagents based on their current costs – thus optimizing the long term cost per ton of NO_x control.

4.3.8 Potential Applicability of Oxidation Technology to TXI Plant

General Discussion. The TXI plant has 4 wet process kilns without any existing wet scrubber system. That would require them to place a complete oxidation system in place as an add-on technology including the scrubber for these systems. Assuming that all of the control options would have a similar capital cost for a spray tower/scrubber system careful evaluation of the alternative reagent systems is warranted.

A trial system for evaluating the reagent systems may be warranted. As an example, three one-month trials using alternative reagents in a skid-mounted scrubber could be performed prior to scaling up to a full system. It may be possible to combine the gas flows from the kiln systems into a single flow to minimize the cost of the scrubber system.

Because of the high moisture levels in the gasses from wet kilns it may be necessary to bypass a portion of the stack gasses around the spray tower/scrubber for use as reheat gas after the spray tower/scrubber to prevent condensation problems in the stack. To the extent that such a strategy is required the efficiency of the NO_x removal would be proportionately impacted.

TXI also has a large modern precalciner kiln with a scrubber system on-site. An oxidative control technology for the precalciner kiln has significant potential to provide NO_x control using the existing scrubber system. A variety of low temperature oxidation reagent systems could be tested for efficiency in the existing wet scrubber system. It should also be relatively simple to set up a temporary system to test the high temperature hydrogen peroxide control option. The critical factor in the successful use of the high temperature hydrogen peroxide control technology will be determining the best location for injection. Careful gas phase temperature measurements and modeling should help determine the optimum location.

For TXI the added benefit of the high temperature hydrogen peroxide control technology might be the added control of hydrocarbons. There is the real potential that at the temperatures, which the hydrogen peroxide system operates at, those hydrocarbons will also be oxidized. Because these hydrocarbons may be evolved from the raw feed at a lower temperature this is not a certainty but, if it were to occur, the potential does exist for such a system to replace the existing catalytic control system. In that event, the savings on natural gas costs would be substantial.

Conclusions. For the precalciner the addition of the high temperature hydrogen peroxide oxidation control technology to the preheater tower has significant potential. In addition to controlling NO_x emissions this oxidation technology has the potential to control hydrocarbon emissions and eliminate the need for the existing catalytic control system and the associated

operating costs. These potential cost savings could more than offset the cost of the hydrogen peroxide and capital investment for this kiln line to achieve even greater NO_x control than its already relatively low levels. Tests of this technology should be able to be conducted with minimal investment. Alternatively tests of various wet scrubber reagent systems could also be conducted in the existing SO_x scrubber system.

In the wet kilns, because of the reheat costs, further investigation of the low temperature oxidation technologies is likely to be the most cost effective and is therefore recommended for further investigation. Combination of midkiln combustion, midkiln SNCR and a low temperature oxidation technology may provide exceptional NO_x control at the most effective aggregate cost per ton of NO_x controlled for these kilns.

Table 4-3.4. Summary of Modeling Results for LoTOxTM on Ellis County Kilns – Performance Results

Existing Unit	Control Technology	Emissions Rate tpy before	Emissions Rate tpy after (a)	Controlled Emissions Rate ppm	Controlled Emission Rate lb./tonne clinker	Control Efficiency %	Reduction tpy
Ash Grove #1- wet	LoTOx TM	702	301.6	60	0.84	85%	400.4
Ash Grove #2- wet	LoTOx TM	750	322.2	58	0.89	85%	427.8
Ash Grove #3- wet	LoTOx TM	764	328.3	53	0.91	85%	435.7
TXI #1 and #4-wet (b)	LoTOx TM	1197	514.3	109	1.21	85%	682.7
TXI #2 and #3-wet (b)	LoTOx TM	121	52	109	0.49	85%	69.0
TXI#5 – dry	LoTOx TM	1710	734.7	29	0.30	80%	975.3
Holcim #1 – dry	LoTOx TM	2222	954.7	73	0.38	85%	1,267.3
Holcim #2 – dry	LoTOx TM	1778	763.9	53	0.30	85%	1,014.1

(a) NO_x emission rate after SCR does not reflect SCR efficiency reduction due to adjustment by the ozone season factor of 0.671 (NO_x reduction is modeled to occur only during the ozone season).

(b) The results for TXI #1 & #4 and #2 & #3 are average per kiln – for example, total emissions reductions for controlling both TXI #1 & #4 are double the value listed in the table.

(c) Models assume mid-kiln firing installed at TXI as required under current SIP.

Table 4-3.5. Summary of Modeling Results for LoTOxTM on Ellis County Kilns – Economic Results

Existing Unit	Control Technology	Capital Cost	Annual Cost	Cost Effectiveness \$/ton NO _x	Energy Penalty or Benefit	Burden Cost \$/tonne clinker
Ash Grove #1- wet (c)	LoTOx TM	\$4.8 MM	\$1.4 MM	\$3,400	(a)	\$5.00
Ash Grove #2- wet (c)	LoTOx TM	\$5.2MM	\$1.5MM	\$3,500	(a)	\$5.40
Ash Grove #3- wet (c)	LoTOx TM	\$5.8MM	\$1.6MM	\$3,700	(a)	\$5.70
TXI #1 & #4–wet (b,c)	LoTOx TM	\$5.4MM	\$1.6MM	\$3,300	(a)	\$4.70
TXI #2 & #3–wet (b,c)	LoTOx TM	\$2.8MM	\$0.5MM	\$11,000	(a)	\$10.50
TXI#5 – dry	LoTOx TM	\$5.2MM	\$2.4MM	\$2,600	(a)	\$0.90
Holcim #1 – dry	LoTOx TM	\$6.7MM	\$3.1MM	\$2,400	(a)	\$2.35
Holcim #2 – dry	LoTOx TM	\$5.4MM	\$2.5MM	\$2,300	(a)	\$1.90

(a) Increased fan power due to pressure drop across scrubber included in the models

(b) The results for TXI 1 & 4 and #2 & #3 are average per kiln – for example, total capital costs for controlling both TXI #1 & #4 are double the value listed in the table.

(c) Costs for wet kilns include addition of spray tower to scrub oxidation products.

4.4 Process Modification

Process modifications are applicable to any type of kiln and are usually done to reduce heat consumption, to improve clinker quality, and to increase the lifetime of the equipment (such as the refractory lining) by stabilizing process parameters. Reduction of emissions, such as NO_x, SO_x, and dust, are secondary effects of these modifications. Smooth and stable kiln operation close to design values for process parameters is beneficial for all kiln emissions. Process modifications can include many elements, such as instruction and training of the kiln operators, homogenizing raw material, ensuring uniform coal dosing, improving the cooler's operation, and installing new equipment. Process modifications are primarily done to reduce operating costs, increase capacity, and improve product quality. Adopting process modifications usually results in a reduction of operating costs for a kiln. The savings result from reduced fuel and refractory consumption, lower maintenance costs, and higher productivity, among other factors. (35)

This section describes process modifications that improve fuel efficiency and kiln operational stability with an emphasis on reducing NO_x formation. Since NO_x formation is directly related to the amount of energy consumed in cement-making, improving fuel efficiency and productivity will reduce NO_x emissions.

4.4.1 Combustion Zone Control of Temperature and Excess Air

Continuous monitoring of O₂ and CO emissions in the cement kiln exhaust gases indicates the amount of excess air. At a given excess air level, NO_x emissions increase as the temperature of the combustion zone increases. A typical kiln combustion zone solids temperature range is about 1,430 to 1,540 °C (2,600 to 2,800 °F) for completion of clinkering reactions and to maintain the quality of the cement produced. (75) The corresponding gas-phase temperature is usually greater than 1,700 °C (3,100 °F). (76) Maintaining the combustion zone temperature at a necessary minimum value would minimize both the process energy requirement and the NO_x emissions.

Along with the appropriate temperature, it is also necessary to maintain an oxidizing atmosphere in the clinker burning zone to ensure the quality of the clinker produced. Although a kiln could be operated with as little as 0.5 percent kiln exhaust oxygen level, typically the kiln operators strive for an oxygen level of one to two percent to guarantee the desired oxidizing conditions in the kiln burning zone. An experimental test on a cement kiln showed that by reducing excess air from 10 to 5 percent (i.e., reducing exhaust oxygen levels from two to one percent) NO_x emissions per unit time can be reduced by approximately 15 percent. (77,78)

With state-of-the-art continuous emissions monitoring systems (CEMS) and feedback control, excess air can be accurately controlled to maintain a level that promotes optimum combustion and burning conditions in addition to lowering NO_x emissions. Reducing excess air level also results in increased productivity per unit amount of energy consumed and thus results in an indirect reduction of NO_x emissions per unit amount of clinker product.

4.4.2 Feed Mix Composition

Heat requirements for producing clinker are dependent on the composition of the raw feed which varies among cement plants. Experiments have demonstrated that by improving the burnability of the raw feed, the heat requirement of clinker can be reduced by 15 percent (79) If the raw feed composition can be formulated to require less heat input per ton of clinker, less fuel

is burned and less NO_x per unit product is produced. This approach of changing the feed composition may, however, be highly site specific and may not be applicable at all locations.

Reduction of Alkali Content of Raw Feed. The alkali content of finished cement generally needs to be below a certain acceptable level. Low alkali requirements need higher kiln temperatures and longer residence times at high temperatures to volatilize the alkali present in the semi-molten clinker. Raw materials with greater alkali content need to be burned longer at higher temperatures to meet alkali requirements and thus may produce greater NO_x emissions. Increased volatilization of alkali also results in increased alkali emissions in kiln exhaust gases. To control alkali emissions, a part of the kiln exhaust gases may be bypassed around a downstream unit, e.g., a precalciner. The bypassed gases are quenched to remove alkali and sent through a particulate collector. The bypass of kiln exhaust gases typically involves a fuel penalty, e.g., about 20,000 Btu/tonne clinker for every one percent gas bypass. The additional heat requirement may also contribute to increased NO_x emissions; thus, reducing the alkali content of the raw feed mix may contribute to a reduction in the NO_x emissions.

4.4.3 CemStar Process

Another feed modification that can reduce NO_x emissions is the addition of a small amount of steel slag to the raw kiln feed. This patented technique is known as the CemStar Process and was developed by TXI Industries. Steel slag has a low melting temperature and is chemically very similar to clinker. Since many of the chemical reactions required to convert steel slag to clinker have already taken place in a steel furnace, the fuel needed to convert steel slag into clinker is low. The decreased need for limestone calcination per unit product and improved thermal efficiency of the process both contribute to reduced thermal NO_x and CO₂ emissions. (80)

Eleven facilities are using or in the process of incorporating CemStar. (81) CemStar requires little extra equipment and the addition of steel slag to the feed mix can result in a reduction or elimination of the need for some mineral sources, such as shale or clay. This process can also increase production by 15 percent. (80)

According to the Entellect Environmental Services “Evaluation of the Effects of the CemStar Process on a Wet Process Cement Kiln” report, the CemStar process reduces the kiln material temperature in the region of the flame by an average of 200°F (from 2,610°F to 2,405°F); the lower gas temperature of the flame results in lower NO_x emissions. (82) Another test of CemStar technology found an average reduction in burn zone temperature of 160°F, a six percent reduction. (82) The amount of NO_x emissions reductions achievable with CemStar varies by kiln type but ranges from over 20 to 60 percent. (80) Short- and long-term tests of CemStar were conducted at two different types of TXI cement kilns in 1999. Short-term tests (two days) on a preheater/precalciner kiln found NO_x emissions reductions in lbs. NO_x/tonne clinker of 44 percent when operated at maximum capacity, and between 9 and 30 percent when operated at normal capacity, depending on the quality of the raw feed mix (see Table 4-4.1).

Table 4-4.1. Results of Short-Term Cemstar Tests on a Preheater/Precalciner Kiln

	Poor Quality Feed Mix (lb. NO _x /tonne clinker)	Percent Reduction ^a (%)	Ideal Quality Feed Mix (lb. NO _x /tonne clinker)	Percent Reduction ^a (%)
Without CemStar	4.98	-	5.59	
With CemStar at normal feed rate ^b	4.51	9	3.89	30
With CemStar at maximum feed rate ^c	(no test)	-	3.15	44

^a Percent reductions are relative to the emission rate without CemStar.

^b The normal feed rate is 170 - 180 tons per hour of dry feed.

^c The maximum feed rate is 195 tons per hour of dry feed.

Andover Technologies also reported on short-term and long-term tests of a wet kiln using CemStar Technology. The short-term tests (one day) found emission reductions of 36 to 55 percent in lbs. NO_x/tonne clinker, and the long-term tests (approximately two and a half months) found reductions of 24 percent (see Table 4-4.2). (80)

Kilns with lower initial baseline NO_x emissions would have less NO_x reduction with CemStar than those with higher baseline emissions. Wet and long-dry kilns would have greater NO_x reductions with CemStar because more energy is used per ton of clinker produced than preheater/precalciner kilns. Wet kilns may achieve the greatest NO_x reductions with CemStar because the addition of steel slag would reduce the amount of water needed to create the slurry and consequently decrease the amount of heat needed to dry it. (80)

Table 4-4.2. Results of Cemstar Tests on a Wet Kiln

	Test 1 (lb. NO _x /tonne clinker)	Test 2 (lb. NO _x /tonne clinker)	Percent Reduction ^a (%)
Short-Term Test			
Without CemStar	17.53	24.7	-
With CemStar	11.24	no 2 nd test	Test 1 = 36 Test 2 = 55
Long-Term Test			
Without CemStar	5.23	no 2 nd test	-
With CemStar		no 2 nd test	24

^a Percent reductions are relative to the emission rate without CemStar.

4.4.4 Kiln Fuel

Changing the primary kiln fuel from natural gas to coal can reduce the flame temperatures significantly, resulting in lower thermal NO_x emissions. (83,84) Although nitrogen present in coal may provide greater fuel NO_x contribution, switching the fuel burned in kilns from natural gas to coal has been shown to provide substantial reduction in the total NO_x emissions in one experimental study. (83) In the dry process kilns tested in this study the average NO_x emissions decreased from 20.4 lb./tonne clinker to 6.2 lb./tonne clinker when the fuel was changed from natural gas to coal. A number of cement kilns have already made the switch from natural gas to coal and currently 87 percent of cement kilns in the United States use coal as the primary fuel. (85)

When natural gas (with no nitrogen in the fuel) is used in the burning zone of a cement kiln, the NO_x emissions are significantly higher than when coal is used. There may be additional environmental impacts when coal is burned as opposed to natural gas (e.g., sulfur dioxide and sulfate emissions may increase). Although switching to a lower nitrogen fuel in a precalciner may reduce NO_x, the fuel nitrogen content in the burning zone has little or no effect on NO_x generation. Some researchers have found no relationship between fuel nitrogen content and the NO_x emissions from a cement kiln. (86)

Switching to a fuel with a higher heating value and lower nitrogen content may reduce NO_x emissions in a cement kiln, e.g., petroleum coke has a lower nitrogen content per million Btu than coal. Petroleum coke is also more uniform in terms of heat value, lower in volatile matter content and burns with a lower flame temperature. However, some claim that petroleum coke cannot be burned alone because it does not provide enough volatile matter. (87)

4.4.5 Increasing Thermal Efficiency

The thermal efficiency of the cement-making process has improved substantially as energy costs have increased and new technology has been developed. Although there are a variety of cement process technologies used in the US, the kilns in this study are all either 1960's wet kiln technologies that are not energy efficient or modern dry process kilns with preheat and precalcination that represent the most energy efficient process for making Portland cement. Both Holcim #2 and TXI #5 are new and energy efficient units. Holcim #1 began operation in 1987 and is slightly less efficient and could potentially be upgraded by options such as calciner modification discussed below. In addition, there are interim steps that improve the efficiency of wet process to semi-wet or semi-dry process. However, the main opportunity for substantial reductions in NO_x emissions in Ellis County from energy improvements comes from closing the wet process units and replacing them with modern, dry-process production.

Calciner Modifications

A study for the Department of Energy (88) evaluates use of low pressure drop cyclones for suspension preheaters. Worrell reports, "Cyclones are a basic component of plants with pre-heating systems. The installation of newer cyclones in a plant with lower pressure losses will reduce the power consumption of the kiln exhaust gas fan system. Depending on the efficiency of the fan, 0.6-0.7 kWh/ton clinker can be saved for each 50 mm W.C. (water column) the pressure loss is reduced. For most older kilns this amounts to savings of 0.6-1.0 kWh/ton (89). Fujimoto (1994) discussed a Lehigh Cement plant retrofit in which low-pressure drop cyclones were installed in their Mason City, Iowa plant and saved 4 kWh/ton clinker (90). Installation of the cyclones can be expensive, however, since it may often entail the rebuilding or modification of the preheater tower, and the costs are very site specific. Also, new cyclone systems may

increase overall dust loading and increase dust carryover from the preheater tower. However, if an inline raw mill follows it, the dust carryover problem becomes less of an issue. A cost of \$2.7/annual ton clinker is assumed for a low pressure drop cyclone system.”

The only candidate for a calciner upgrade among the Ellis County kilns is Holcim #1. This process line represents a slightly older version of the technology than Holcim #2 or TXI #5. Low-NO_x and low energy consumption performance is largely inherent in the design and Holcim #1 would appear to be the unit that could best benefit from this upgrade. Cost modeling has been provided based on the assumption that this unit could move to a level of performance similar to TXI #5 after the upgrade. The expert panel reviewed the current performance of the Holcim kilns in comparison to TXI #5. Although Holcim #2 and TXI #5 were both built near the year 2000, TXI #5 has typical NO_x emissions that are substantially lower than Holcim #2. It was the judgment of the expert panel that an intrinsic low- NO_x redesign of Holcim #1 should produce performance more similar to that of TXI #5 than Holcim #2. These results are provided in Table 4-4.5.

Semi-Wet Upgrades to Wet Kilns

Hendriks and Worrell (91) report that conversion from a wet to a semi-wet process can save between 0.8 and 1.6 GJ/tonne clinker. There is a penalty of increased electrical energy use of approximately 3 to 5 kWh associated with this conversion.

Worrell (88) also reviews this option and describes it as a filter press system. “In the wet process the slurry typically contains 36% water (range of 24-48%). A filter press can be installed in a wet process kiln in order to reduce the moisture content to about 20% of the slurry and obtain a paste ready for extrusion into pellets (92). In the U.S. several plants have tried slurry filters, but have not been very successful. Currently, there seem to be no plants in the U.S. using this technology (93). Additional electricity consumption is 3-5 kWh/ton clinker (94). In this analysis it is assumed that energy use increases by 4 kWh/ton clinker to reduce the moisture content to 20%. The corresponding fuel savings are 1.0 MBtu/ton (94). Jaccard and Willis (1996) estimate the conversion cost to run \$1.6/annual ton clinker capacity with increased operation costs of \$0.1/ton clinker (95).”

Semi-Dry/Semi-Wet Upgrades to Wet Kilns

Hendriks and Worrell (91) report that conversion from a wet to a semi-dry process can save approximately 2.0 GJ/tonne clinker. They report a “small” increase in electrical energy use associated with this conversion of approximately 3 to 5 kWh.

Buzzi-Unicem operates a semi-dry/semi-wet system in Greencastle, IN, which had been converted from a large wet kiln system. While anticipated increases in production capacity were achieved, predicted improvements in thermal efficiency were not fully realized. Actual thermal efficiency improvement was only about 15%. Capital cost for this type of conversion are likely to be in the range of \$75-85/tonne. Significant NO_x improvements have been observed in this conversion although not to the levels predicted by the vendor. Even with a 50% increase in production total NO_x emissions have been significantly reduced.

Because kiln conversion economics are significantly impacted by the size of the existing kiln the conversion of any of the wet kilns at TXI or Ash Grove is not considered a feasible alternative for further analysis.

Replacement of Wet Kilns with Dry

Worrell evaluates conversion of a wet kiln to a dry preheat/precalciner process (88). This conversion is essentially a reconstruction of the main kiln and processing areas with a new, modern dry plant. Worrell reports “If economically feasible a wet process kiln can be converted to a state-of-the art dry process production facility that includes either a multi-stage preheater, or a pre-heater/pre-calciner. Average specific fuel consumption in U.S. wet kilns is estimated at 6.0 MBtu/ton clinker. Studies of several kiln conversions in the U.S. in the 1980s found fuel savings of 2.9 MBtu/ton or less (96). In Hranice (Czech Republic) a 1,050 tonne per day wet process plant was converted to a dry kiln plant with a new kiln specific fuel consumption of 2.7 MBtu/ton clinker (97). Fuel savings of 2.7 MBtu/ton clinker and an increase in power use of about 9 kWh/ton clinker (98) are assumed. The cost of converting a wet plant to a dry process

plant may be high, as it involves the full reconstruction of an existing facility. Costs may vary between \$50/annual ton clinker capacity and \$100/annual ton clinker capacity (99,100).”

This option is also discussed by Hendriks (91). Hendriks gives a cost of approximately \$133/tonne of annual capacity as the cost of building the new dry process plant. Hendriks estimates that about 2.2 GJ/tonne of energy can be saved. Increased energy use of about 10kWh/tonne is required for operation of the preheat/precalcination tower. These models do not consider any lost revenues that may be associated with wet to dry conversion. Certain types of cement, such as oilfield cement, are typically produced by wet kilns. This means that a plant that converts from a wet to dry process may lose some revenues. Companies that operate wet kilns and companies that operate preheat/calcliner kilns are likely to have differences of opinion about the magnitude of difference in cement quality. This cost impact depends on the amount of materials sold by a particular plant and may include subjective criteria regarding cement qualities that cannot be quantified as part of this project.

Wet to Dry Conversion of Ellis County Kilns

On average, dry preheat/precalcliner kilns emit substantially less NO_x per tonne of cement produced and require less energy per tonne of cement produced. Both in terms of energy use and NO_x emissions rates, the wet process units are often nearly double the modern dry process units. The cost modeling presumed that the wet kilns could obtain a value approximately that of high performing modern kilns and that would result in an approximate 65% decrease in NO_x emissions. A substantial energy savings was predicted to result in fuel savings in the cost models (see Confidential Attachment Wet to Dry Conversions).

The economics of wet kilns compared to dry kilns are very complex and involve issues such as lower production capacity of wet kilns, use of waste fuels and quality of cement products. However, as the energy costs of wet production are higher than for modern dry process units, there is a point at which the higher costs of pollution controls that may result from the final determinations of this study would trigger a decision to close the wet kilns and replace them with dry. Stating this another way, it is likely that at a certain cost of pollution controls in terms of dollars per tonne of clinker produced, the economics of the wet process including higher

fuel costs and higher pollution control costs would reach a point where replacement of the wet units with larger dry process units would be the reasonable alternative for a cement plant to continue operations at that site.

It is likely that any new kilns built to replace the wet kilns in Ellis County would include increased production capacity in the economic justification. However, for purposes of control cost modeling, the units need to replace the existing capacity for the evaluations to make sense in the context of our control option evaluations. For this reason, two dry process kiln replacement scenarios were modeled. One involved replacing the three wet kilns at Ash Grove with one new dry process unit and the second involved replacing the four wet kilns at TXI with one new dry process unit. The capacity of the new units was modeled as essentially equal to the capacity of the existing wet units combined. It is likely that Ash Grove and perhaps TXI would replace the existing kilns with a new dry preheat/precalcination process typical of current generation dry process plants with approximately twice (over two million tons per year of clinker) the capacity of the existing wet kilns (under one million tons per year of clinker) and the added production capacity would be an important part in cost justification of the expense of the new dry process unit.

The modeling, summarized in Table 4-15, shows an annualized cost of approximately \$11 per tonne clinker for the replacement dry process units. This cost includes an annual benefit of approximately \$4.0 to \$4.5 million in reduced fuel costs. An increased annual cost of electricity of approximately \$0.5 million results from the additional fan power required to move air through the preheat and precalcination tower. This information indicates that energy savings are very significant, but are not sufficient for a company to justify replacement of the wet kilns. Annual operating costs (capitalization of the new equipment) are reduced by nearly one third to approximately \$9 million dollars by energy savings; however, even with the current high costs of energy this would not by itself justify replacement of the wet kilns.

The current use of alternative fuels complicates this analysis. The fuel savings are based on an assumption that the energy for the current wet kilns is all based on coal. Lower cost alternative fuels lessen the economic benefit of the increased energy efficiency. Preserving these alternative fuel programs may be important economic considerations in company analyses of wet

to dry conversions and the overall economics of cement production on a dollars per tonne clinker basis. The realistic assumption that larger modern units of a size similar to TXI #5 are needed to achieve the energy efficiency desired and using increased production to offset the high cost of these projects both impact fuel economics. If it is assumed that the current amounts of alternative fuels are permitted to be used in a new larger kiln, the amount of coal predicted to be reduced would still be reflected in the overall reduction in fuel use.

Conversion of the Ellis County wet kilns to dry process would result in year-round emissions reductions for NO_x, SO₂, particulate matter and hazardous air pollutants. The modern dry process unit would have updated controls that would result in potentially large emissions reductions for SO₂ and other air quality benefits for the region including reduction in fine PM precursors.

Table 4-4.3. Summary of Modeling Results for Wet to Dry Conversion of Ellis County Kilns – Performance Results

Existing Unit	Replacement Unit	Emissions Rate tpy before	Emissions Rate tpy after (a)	Controlled Emissions Rate ppm	Controlled Emission Rate lb./tonne clinker	Control Efficiency %	Reduction tpy
Ash Grove #1- wet	Ash Grove #4 - dry	2,200	772	180	1.99	65%	1,428
Ash Grove #2- wet							
Ash Grove #3- wet							
TXI #1 -wet	TXI #6 – dry	1,800	630	180	1.94	65%	1170
TXI #2 -wet							
TXI #3 -wet							
TXI #4 -wet							

Table 4-4.4. Summary of Modeling Results for Wet to Dry Conversion of Ellis County Kilns – Economic Results

Existing Unit	Replacement Unit	Capital Cost	Annual Cost	Cost Effectiveness \$/ton NO _x	Energy Penalty or Benefit*	Emissions Penalty or Benefit**	Burden Cost \$/tonne clinker
Ash Grove #1- wet	Ash Grove #4 - dry	\$169 M	\$9.3 M	\$6,500	-\$4.4 M	-1,428 tpy	\$10.94
Ash Grove #2- wet							
Ash Grove #3- wet							
TXI #1 -wet	TXI #6 - dry	\$143 M	\$7.9 M	\$6,700	-\$3.7 M	-1,170 tpy	\$10.94
TXI #2 -wet							
TXI #3 -wet							
TXI #4 -wet							

* Large benefit in fuel efficiency partly offset by increased electrical use in tower

** Large benefit in reduced fuel – does not account for increased emissions at power plant for power used in tower.

Table 4-4.5. Summary of Modeling Results for Calciner Upgrade for Ellis County Kilns – Economic Results

Control Technology	Control Technology Status	Emissions Rate Before Control tpy	Emissions Rate Before Control lbsNO _x /tonne	Percent Control	Emissions Reduction from Control tpy	Controlled Emission Rate lbNO _x /tonne	Cost Effectiveness \$/ton NO _x	Burden Cost \$/tonne clinker
Holcim #1	Available	2,222	3.76	40%	888.8	2.2	\$2,795	\$2.70

40% for new low-NO_x calciner based on TXI #5 performance.

Cost effectiveness for calciner upgrade calculated by ratio of burden costs using SCR data.

Calciner upgrade is not a seasonal ozone measure – emissions benefit is for full year.

4.5 Performance of Current NO_x Control Techniques and Technologies in the Cement Industry

4.5.1 Comparison of Current Performance of NO_x Control Technologies

Table 4-5.1 is a spreadsheet that is too large for inclusion as a table in the body of this report. This table compares the performance of different technologies against a standard performance criterion of pounds of NO_x per tonne (lbs./tonne) of clinker produced. Only information on complete references is included in this table. When sufficient information could be located to identify the plant and calculate performance of the control technology in lbs./tonne clinker, the information was included in this table. There are additional, less complete references to performance in this report that could not be included in this table because insufficient information was available to compare performance.

4.5.2 Summary of Current Regulations

This report focuses on evaluating the NO_x control measures for Portland cement manufacturing that go beyond current 30 TAC Chapter 117 requirements. In the US, it appears that several areas of the country are in a similar position to Texas in that they are currently evaluating more stringent active controls of NO_x for ozone attainment under the 8-hour standard. While active NO_x controls may be required under New Source Review requirements, current State SIP requirements are less stringent. ERG reviewed and summarized current US NO_x control requirements for cement kilns and this summary is presented in Attachment D as Table D-1. This review showed that four states had performance standards that were similar in stringency to Texas (Maryland, Illinois, Indiana and Michigan). Five states (Pennsylvania, South

Carolina, Tennessee, Ohio and Alabama) had technology based standards that were similar in stringency to the option under Texas regulations to comply by installing a technology such as mid-kiln injection instead of meeting a specific performance standard. Kentucky and California's South Coast Air Quality Management District has standards that appear to be less stringent than Texas. New York uses a case-by-case approach so that the stringency of the regulation is not clear. States are currently considering more stringent measures to comply with the NO_x SIP Call and with projected noncompliance with the 8-hour ozone standard. Both the State of Georgia and the Great Lakes States are considering more stringent control requirements of cement kilns; these measures are discussed below.

Control requirements in Europe are generally moderately stringent emissions limitations based on a performance requirement such as 500 mg/m³. These requirements have prompted use of SNCR (recent documents report as many as 50 installations), but generally are not stringent enough to require higher performing technologies. One exception is Sweden, that has a very stringent performance requirement of 200 mg/m³ (approximately 98 ppm). There are currently two cement plants in Europe capable of meeting this 200 mg/m³ limit. The Solnhofen Portlandzementwerke in Germany (using SCR) and Scancem Slite in Sweden (using SNCR with multi-point injection). European control requirements are presented in Tables 4-5.2 and 4-5.3

Japan has a national standard for NO_x from cement plants and divides the emissions limits into those that apply to plants built before 1975 and those built after 1975. For pre-1975 plants the NO_x standard is 480 ppmv and for those built after, the standard is 250 ppmv. The 250 ppmv standard is very similar to the German standard of 500 mg/m³. For the purposes of evaluating the particulate matter standards table, a US standard of 0.02 grains per dry standard cubic foot would be equivalent to a European standard of 50 mg/Nm³.

As noted above, the US is somewhat behind Europe in requiring active controls on Portland cement manufacturing plants. Communications between TCEQ and EPA Region 6 indicate that recent BACT determinations typically require 1.95 lbs./tonne clinker (2.15 lbs./tonne) and SNCR. Other recent US studies include planning studies for compliance with the 8-hour ozone standard.

Two recent documents that recommend measures beyond current 30 TAC Chapter 117 requirements are the Midwest Regional Planning Organization's "Identification and Evaluation of Candidate Control Measures, April, 2005" and the "Fall Line Air Quality Study. November, 2004". Both of these studies are evaluations of potential measures to reduce ozone and recommend consideration of SCR for control of cement kilns. The Fall Line Study was conducted for the State of Georgia and recommends SCR for wet kilns as well as dry process kilns and provides estimates of cost effectiveness per ton of NO_x controlled. The Midwest RPO Study also discusses the potential for control of wet kilns with SCR, particularly for low-dust applications (after pollution controls) and mentions the high cost of gas reheat as a limitation in application of this technology. SCR costs are only estimated for long dry and dry preheat/precalcination process kilns. The cost information from these two studies is summarized in Tables 4-5.4 and 4-5.5.

Table 4-5.2. National SO₂ and NO_x Emission Limits for the Production of Cement Within the European Union (EU 15), in mg/Nm³, Around 2000

Country	Data Based on	New/Modified or Existing Plant	SO ₂ Normal Situation	SO ₂ S-rich Raw Materials	NO _x	PCDD/Fs* ng TEQ/Nm ³
Austria	Na (a)	New/modified	200	400	500	
		Existing	200	400	1000	
Belgium	P	New/modified	1000		1800	
		Existing	1000		1800	
Denmark	P (a)	Existing	5/250/450 (b)	No limit	1200/2500/850 (c)	no limit
Finland	P (d)	Existing	150–400		1200–1800	
France	Na	New/modified	500	1200/1800 (f)	1200/1500/1800 (g)	
		Existing	500 (e)	1200/1800 (e)(f)	1200/1500/1800 (g)	
Germany	Na	New/modified	400	400	500	
		Existing	400	400	800	
Greece						
Ireland	Na	New/modified	400	700	1300	n.a.
		Existing	400	700	1300	n.a.
Italy	Na/P	New/modified	600		1800	10000 (h)
		Existing				10000 (h)
Luxembourg	P	Existing	100 (i)		80(j)	0.1 (k)
Netherlands	P	Existing	(l)		1300(j)	0.1
Portugal	Na	New/modified	400	1300		0.1
		Existing				0.1
Spain	Na	New/modified	2400/6000 (m)	2400/6000 (m)	1300-1800 (n)	
			600 (n)	1800 (n)		
		Existing	2400/6000 (m)	2400/6000 (m)		
		600 (n)	1800 (n)			
Sweden	P	Existing	-	<200	<200	0.1
UK	Na (o)	New/modified	200 (p)(q)	600-2500 (r)	900 (p)	
		Existing			500-1200 (q)(s)	

Source: EIPPC Cement BREF (2000). Based on Cembureau report (1997) and information provided by experts of the Technical Working Group set up in order to support the production of the BREF

* Polychlorinated dibenzo dioxins and furans (total emitted quantity in nano g/ Norm m³).

Na = National law; R=Regional law; P=Typical permit; in mg/ Norm m³.

a) Daily averages and reference condition of 273 K, 101.3 kPa, dry gas and 10% O₂.

b) 5 for semi-dry process, 250 for wet process and 450 for wet process with wet scrubber and heat recovery. Limits under discussion.

c) 1200 for semi-dry process, 2500 for wet process and 850 for wet process with wet scrubber and heat recovery. Limits under discussion.

d) Monthly averages, reference condition of 10% O₂ and dry gas.

e) Existing plant must meet limit for new plant by 2001.

f) 1200 mg/Nm³ if ≥ 200 kg/h; 1800 mg/Nm³ if < 200 kg/h.

g) 1200 mg/Nm³ for dry process with heat recuperation, 1500 mg/Nm³ for semi dry and semi wet processes, and 1800 mg/Nm³ for wet and dry processes without heat recuperation.

h) General rule for any kind of industrial emission.

i) Half hour average.

j) Daily average value.

k) 6 hour average.

l) 90 kg/h as daily average, maximum 375 tonne/year.

m) Current limits.

n) Limits under discussion.

o) IPC Guidance Note S2 3.01.

p) 'Benchmark releases'.

q) Benchmark releases are, in particular, not applicable to existing plant but are a factor in considering appropriate limits.

r) Limit values reflect the actual levels of releases. Daily averages and reference condition of dry gas and actual O₂ content.

s) Actual releases, daily averages, not all plants currently have limits.

Table 4-5.3. National Emissions Standards for PM of the European Union Countries for Cement Manufacturing in mg/Nm³

Country	Data Based on	New/Modified or Existing Plant	Kiln Stack	Clinker Cooling	Cement Grinding	Other Point Sources
Austria	Na (a)	New/modified	50	50	50	50
		Existing	50	50	50	50
Belgium	P	New/modified	50	50	50	50 – 300
		Existing	50 - 150	50 - 400	50 - 150	
Denmark	P	Existing	50 (b)	50 (b)	50 (b)	50 (b)
Finland	P	New/modified	50	50	30 – 50	30 – 50
		Existing	50 (c)	50	30 - 50	30 – 50
France	Na	New/modified	50	100	50	30
		Existing	50 (d)	100 (d)	50 (e)	30
Germany	Na	New/modified	50	50	50	50
		Existing	50	50	50	50
Greece	Na/R	New/modified	100	100	100	
		Existing	150	150	150	
Ireland	Na	New/modified	50	100	75	50
		Existing	50	100	75	50
Italy	Na/P	Existing	50	50	50	50
Luxembourg	P	Existing	30 (f)			
Netherlands	P	Existing	15 (f)	10 (f)	10 (f)	10(f)
Portugal	Na	New/modified	50	100	75	50
		Existing	100	100	75	50
Spain	Na	New/modified		170/100 (g)	300/250 (g)	300/250 (g)
				100 (h)	75 (h)	50 (h)
		Existing	400/250 (g)	170/100 (g)	300/250 (g)	300/250 (g)
			100 (h)	100 (h)	75 (h)	50 (h)
Sweden	P	Existing	50 (i)	50	50	20
UK	Na (j)	New/modified	40 (k)	50 (k)	40 (k)	50 (k)
		Existing	(l)	(l)	(l)	(l)

Na= National law; R= Regional law; P= Typical permit

a) Daily averages and reference condition of 273 K, 101.3 kPa, dry gas and 10% O₂.

b) Limits under discussion. Reference condition of 273 K, 101.3 kPa, dry gas and 10% O₂.

c) Existing plant must meet 50 mg/Nm₃ by January 1, 2001. Monthly averages and reference condition of 10% and dry gas.

d) Existing plant with emission < 150 mg/Nm₃ must meet limit for new plant by 2001.

e) Existing plant must meet limit for new plant by 2001.

f) Daily average values.

g) Current limits.

h) Limits under discussion.

i) Daily average value. A limit value of 90 mg/Nm₃, including start/stop and CO-trips, applies for monthly averages.

j) IPC Guidance Note S2 3.01.

k) "Benchmark releases."

l) Benchmark releases are, in particular, not applicable to existing plant but are a factor in considering appropriate limits.

[Based on [Cembureau report, 1997] and information provided by the Technical Working Group of the European Commission BREF Report (2000)].

**Table 4-5.4. Midwest RPO – LADCO Study
(Large Preheater Kiln SCR 1,200,000 tpy clinker 2,880 tpy uncontrolled emissions)**

	70% Removal Efficiency		90% Removal Efficiency	
	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment – TCI	\$1,760,296	\$14,668,188	\$1,760,296	\$14,668,188
Total Annual Cost	\$1,305,377	\$3,040,107	\$1,305,377	\$3,040,107
Pollutant Removal - tpy	2,016	2,016	2,592	2,592
Cost Per Ton of NO _x Removed	\$648	\$1,508	\$504	\$1,173

Table 4-5.5. Fall Line Air Quality Study (Georgia)

Medusa Cement (Houston)	In-process fuel use – coal	SNCR	\$1,726	
	Cement manufacturing dry	Mid-kiln firing	\$62	
	Cement manufacturing wet	Mid-kiln firing	\$62	
		SCR	\$3,947	Mid-kiln

In summary, current US emissions limitations indicate that 1.95 lbs./tonne clinker using SNCR is currently considered BACT for dry kilns. In order to meet 8-hour ozone standards, several areas of the country are looking at requiring more stringent NO_x controls on Portland cement plants and at least two areas are looking at requiring SCR. Experience in Europe indicates that emissions levels of approximately 200 mg/m³ (98 ppm) and less than 1.0 lb./tonne clinker are being achieved at two dry precalciner kilns, one using SNCR and one using SCR.

4.5.3 Summary of European Experiences

In Europe, many cement plants have adopted general primary measures, such as process control optimization, use of modern, gravimetric solid fuel feed systems, optimized cooler connections and use of power management systems. These measures are usually taken to improve clinker quality and lower production costs but they also reduce energy use and air emissions.¹

In March 2000, the European Integrated Pollution Prevention and Control (IPPC) Bureau issued a report on Best Available Techniques for European cement kilns. (35) The report collected emissions data from several sources. Emission rates for European kilns included in this

study range from less than 0.8 to 12 lb. NO_x/tonne clinker. A set of German kiln emission measurements presented in the European report found NO_x emissions for a cyclone preheater with heat recovery of 1.2 to 6.2 lb./tonne clinker, for a cyclone preheater without heat recovery of 1.6 to 7.0 lb./tonne clinker, and for a grate preheater of 1.6 to 8.2 lb./tonne clinker. These rates are similar to the averages for preheater and precalciner kilns found by EC/R in the new data presented in Chapter 4 (1.7 and 2.7 lb./tonne clinker respectively), but are less than those reported in the ACT document (5.9 and 3.8 lb./tonne clinker respectively). (35)

Table 4-5.5 presents a summary of NO_x control device applicability, reduction efficiency, and reported average emissions from the IPPC Bureau report on BAT for European cement kilns. (35) There are no emissions data in the IPPC report for kilns with CemStar technology or midkiln firing. For low-NO_x burners, the IPPC report found a lower average NO_x emissions rate (1.6 lb./tonne clinker) than EC/R found in the new State data (8.98 lb./tonne clinker). Both the IPPC report and the 1994 ACT document had estimated reduction efficiencies for low- NO_x burners of up to 30 percent. The reduction efficiencies in the IPPC report for SNCR (10 to 85 percent) and SCR (85 to 95 percent) are close to but slightly greater than those reported in the 1994 ACT document (30 to 70 percent and 80 to 90 percent respectively). (35)

Table 4-5.5. NO_x Control Techniques Summary From European Best Available Techniques Report (35)

Technique	Kiln Systems Applicability	Reduction Efficiency	Reported Emissions	
			mg/Nm ^{3 a}	kg/tonne ^b (lb./ton)
Flame cooling	All	0 to 50%	400	0.8 (1.6)
Low-NO _x burner	All	0 to 30%		
Staged combustion	Preheater and Precalciner	10 to 50%	<500 to 1000	< 1.0 to 2.0 (2.0 to 4.0)
Mid-kiln firing	Wet and long dry	20 to 40%	no info	no info
SNCR	Preheater and Precalciner	10 to 85%	200 to 800	0.4 to 1.6 (0.8 to 3.2)
SCR - data from pilot plants only	Possibly all	85 to 95%	100 to 200	0.2 to 0.4 (0.4 to 0.8)

^a Normally referring to daily averages, dry gas, 273 K, 101.3 kPa and 10% O₂.

^b kg/tonne clinker is based on 2000 m³/tonne clinker.

The IPPC report concludes that BAT for reducing NO_x emissions are a combination of general primary measures, primary measures to control NO_x emissions, staged combustion and SNCR. The BAT emission level associated with the use of these techniques is 0.4 to 1.0 lb./tonne clinker (200-500 mg NO_x/m³ (as NO₂)). This emission level could be seen in context of the current reported emission range of 0.4 to 6.0 lb./tonne clinker (<200-3000 mg NO_x/m³), and that the majority of kilns in the European Union is said to be able to achieve less than 2.4 lb./tonne clinker (1200 mg/m³) with primary measures. (35)

While there was support for the above concluded BAT to control NO_x emissions, there was an opposing view that the BAT emission level associated with the use of these techniques is 1.0 to 1.6 lb./tonne clinker (500-800 mg NO_x/m³ (as NO₂)). There was also a view that selective catalytic reduction is BAT with an associated emission level of 0.2 to 0.4 lb./tonne clinker (100-200 mg NO_x/m³ (as NO₂)). (35)

5.0 CHEMISTRY OF ELLIS COUNTY MATERIALS AND IMPACTS ON CONTROL DETERMINATIONS

In order to evaluate the characteristics of feed material and their potential impacts on controls, the expert panel worked together to select the parameters they determined necessary for their evaluations. During the team's site visits, it was determined which of these parameters could be supplied by the companies, and which would need to be obtained through chemical analyses. The expert panel assisted TCEQ in preparing an information request for the parameters that could be obtained from the plants and a sampling protocol for the additional chemical analyses that would be required. The additional testing that was required is discussed below under analytical results.

5.1 Analytical Results

Analysis was conducted to determine the chemical, mineral and elemental composition of limestone and other raw materials used in clinker production in Ellis County. Total organic carbon, total sulfur, various forms of sulfur including sulfite and sulfate, chloride, and total Kjeldahl nitrogen content were determined. Three samples of each type (dry powder, wet slurry, slag) were collected from representative operating kiln sites using Ellis County limestone feed material. Analyses were chosen based on the need to identify composition that was expected to affect NO_x emissions or control option performance.

Total organic carbon results are determined using a technique known as differential scanning calorimetry (DSC). Analyses are carried out in gas with a composition of 20% carbon dioxide, 3% oxygen, and 77% nitrogen similar to the basic constituents of kiln flue gas. This causes an oxidative pyrolysis, which closely parallels actual kiln conditions. The formation of char residues is very unlikely for this testing method. Several samples were also analyzed by an alternative technique that gradually heats the material electrically from an external source using nitrogen as the carrier gas. The results reflect a pyrolysis regimen and provide additional supplemental data on the temperature profile at which carbon is released.

Total Kjeldahl Nitrogen (TKN) is a measure of organic nitrogen and ammonia in any form found in the samples. Total nitrogen results are determined by a heated digestion of the

samples. The ammoniacal nitrogen is the most volatile form of nitrogen. The TKN test does not measure nitrite or nitrate. Since nitrate and nitrite nitrogen would not react with NO_x they are of little interest for the feed evaluation.

There are some distinct differences among the feed types that are independent of the incinerator site or treatment. Slag is a manufactured feed material that aids burnability and so would be expected to reduce thermal NO_x generation. It also has lower content of some of the key chemicals of concern for emissions control or new control technology application. For instance, nitrogen and total sulfur in slag is less than the amount found in wet slurry or dry powder, sulfate in slag and slurry less than sulfate in dry powder, and pyritic sulfur in slag is present at lower concentrations than pyritic sulfur in all other feed types. As a percent of total mass, organic sulfur tends to be higher in slag than other feed materials. There is a caveat: The methodology used by the laboratory lumps organic sulfur with simple sulfide (non pyrite). The sulfate in feed tends to be relatively constant compared to other compounds tested in the feed material. Site specific results of kiln feed sample chemical analysis are summarized in confidential attachments for each kiln site (Appendix A, B, and C, and Tables 1 through 5). Results are summarized in the remainder of this section.

5.1.1 Organic Carbon

One set of kiln feed materials had higher organic content than all others. Organic carbon in these dry feed materials is much greater than in all other feed material. Organic carbon in wet slurry from the same site is also higher than the organic carbon in other slurry feed materials. One kiln dry feed material had higher total organic carbon than the others in this sample set. The highest carbon containing feed material also contained higher organic nitrogen. This site also demonstrated lower NO_x emissions than other sites. Results for feed sample carbon analysis from this site are provided in confidential data Appendix A.

The lowest organic carbon content was found in dry powder limestone feed from a different site and supplier. The organic content in these feed materials is quite variable, Total nitrogen was also lower in samples from the same site. This site demonstrates higher NO_x

emission than other comparable sites. Results of percent carbon analysis in feed are shown in confidential data Appendix B.

Most of the organic material in the dry feed is released between 350 and 500 °C indicating high molecular weight organic or pure carbon material. It was noted in the DSC data that some of the samples began generating heat at temperatures below 150 °C, while others only began above 200 °C. The higher temperatures required to liberate the carbon are a function of the volatility (molecular weight) of the carbonaceous material. It is not known whether this has any effect on NO_x emissions, but could influence VOC emissions. However, NO_x emissions were lower from the site supplying samples containing higher molecular weight carbon compounds. Efforts to control VOC emission should take into account the resulting oxidative conditions that do not favor reduction of NO_x.

The pattern of organic combustion determined by DSC appears to be fairly similar for all samples, except of course the slags. Much of the exothermic activity at 400-450 °C for all kiln feeds is probably attributable to pyrite oxidation. In preheater or calciner kilns, this may be occurring in Stage 2 of the preheater. Whether this has any impact on NO_x emissions is questionable. It is possible, of course, that nascent, freshly formed SO₂ may reduce NO₂.

The results for total heat generated during carbon analysis by the alternative nitrogen purged technique appear to be higher for samples containing higher molecular weight carbon. The heat release results for these higher carbon containing samples show characteristics indicating considerable amounts of char, as evidenced by the lower heating results vis-à-vis the DSC results on samples analyzed using both approaches. If this char is produced in the kiln, it may serve as a reducing agent for NO_x assuming it was available in the hot zone of the process, or it may be oxidized to CO which itself may be acting as a reducing agent. The additional carbon could be a partial explanation for the very low NO_x emissions at this site.

5.1.2 Total Kjeldahl Nitrogen

The high carbon content feed also has the highest Total Kjeldahl Nitrogen (TKN) content. Dry powder feed from this site contains slightly more Total Kjeldahl Nitrogen (TKN)

than similar dry feed materials from other sites. While the ratio of %carbon to TKN feed materials is approximately the same for all samples, the total carbon and TKN in wet slurry from sites generating higher NO_x is less than that found in sites using dry powder limestone feed that generate lower NO_x emissions. Results sorted by TKN values are shown in separate tables in confidential Appendices A-4, B-4, and C-4. Assuming the TKN nitrogen is the nonvolatile nitrogen component of the feed, it is likely to be organic based and that nitrogen and carbon are released in the process from the feed at approximately the same time. Such nitrogen release could act as a source of ammoniacal nitrogen at high temperatures, which could establish a quasi-”SNCR/SCR” reductive path for NO, particularly in the presence of iron based catalysts, which at that point in the process have not yet been converted to the ferrite phase of cement clinker, and so may exert a catalytic action. This is admittedly unproven.

5.1.3 Total Sulfur

Total Sulfur and speciated sulfur results are shown in Appendices A, B, and C, and confidential Tables A-4 through C-4. Total sulfur in samples with higher carbon and nitrogen is generally higher than total sulfur from other kiln sites. Total sulfite in dry feed material follows the same trend with the highest carbon containing material also showing the highest sulfur as sulfite. Pyritic sulfur content in high organic samples trends higher than other kiln sites.

5.1.4 Summary of Analytical Results

As discussed above, the results of the testing conducted at the three Ellis County plants to characterize feed materials are considered confidential business information and are, therefore, reported in confidential attachments to this report. The table below summarizes testing results. All feed material is averaged together for the results below and the slag samples are omitted. Averaging the results from the three plants provides protection of confidentiality. As the slag material was understood to be obtained from only one source, this information could not be presented in a manner that protected confidentiality. Table 5-1.1 presents the results for both wet and dry feed materials averaged together, as there are only two plants running wet and two running dry, reporting the results of the averages of two plants’ data does not protect confidentiality.

Table 5-1.1. Summary of Analytical Results on Feed Materials

	Carbon Evolution Temp. range, °C	Total DH, J/g	Organic %	Organic Sulfur %	Pyritic Sulfur %	Sulfate %	Sulfite %	Sulfur %	Chloride (Water Soluble) %	Kjeldahl Nitrogen mg/kg
mean	NA	161.01	0.320	0.110	0.295	0.099	0.035	0.539	0.003	236.27
std. deviation	NA	51.73	0.1028	0.0346	0.0696	0.0296	0.0207	0.0782	0.0012	93.73
range	115-630	NA	NA	NA	NA	NA	NA	NA	NA	NA

5.2 Data from Plant Surveys

The other source of data on the composition of feed materials was an information request that the expert panel assisted TCEQ in preparing and forwarding to the plants. This information was also requested to be treated as confidential by the plants. As discussed above, data from all three plants was averaged to protect confidentiality. Although other data were requested and obtained, when less than all three plants reported a parameter, that parameter was not included in Table 5.2.1 to protect confidentiality.

Table 5-2.1. Summary of Plant Reports on Feed Materials

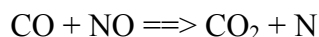
	Feed Composition (% wt typical)				Kiln Feed			Size	Sulfur
	Limestone	Shale	Silica	Other	Lime Saturation Factor	Silica Ratio	Alkali	% + 200 mesh	weight %
mean	88.1%	3.8%	5.8%	2.4%	100.9%	2.985	0.4927	29.5%	1.3%
std. deviation	0.0078	0.0359	0.0238	0.0076	0.0494	0.3066	0.1153	0.2948	0.0023

5.3 Conclusions

Total carbon nitrogen and sulfur content seem to be major factors in the difference between kiln feed materials. TKN can impact NO_x emissions by oxidation to NO, but also as a component that may reduce NO formed in the burning zone, by a reaction similar to SNCR or SCR. We do not know the temperature profile of organic nitrogen generation from these feeds, only that nitrate or nitrite nitrogen is not reflected in the values. However, process emissions tests from the site providing highest carbon organic nitrogen and sulfur also show the lowest

uncontrolled NO_x release. Other sites use dry powder feed material contains slightly lower levels of TKN but do not show the organic carbon or nitrogen content found in the lower NO_x emitting site.

Feed nitrogen under high carbon loading may be released into a reducing environment and need not generate NO. The temperatures required for organic carbon and nitrogen release are too cold for authentic SNCR, and the process doesn't have the right catalysts for SCR. However, the low NO emissions at the site with the higher carbon in feed limestone suggest that these latter reactions may be occurring. One possible conclusion from the feed analysis information is a reaction under reducing conditions, similar to SNCR or SCR, as follows:



While this site may not have the right temperature/oxygen/CO conditions in the tower for SNCR to be maximally effective, there seems to be some combination of chemistry and process conditions occurring that reduces the NO_x emissions. Further evidence of this possibility can be found in a paper from Zement-Kalk-Gips (German cement journal) written by M. Ono and co-workers, Japan, the authors show the effects of certain iron compounds in catalyzing the reaction of carbon monoxide with NO at temperatures below those usual in SNCR (the reference for this report has not been located).

It is possible that the calciner design and process conditions at the site with the lowest NO_x emissions may be better in general or that its design may produce the right conditions for reduced NO_x emissions with the higher carbon/higher organic nitrogen containing feed. Several additional feed analyses (e.g. temperature related nitrogen release, speciated metals analysis) coupled with measurement of gases in kiln emissions are necessary to validate this conclusion.

SO₂ is a high-temperature scavenger for high oxygen radicals like OH and O, and may thereby help reduce NO_x. Feed material containing higher carbon and a higher level of sulfur than other kiln feed materials may contribute to the reducing environment and lower NO_x.

emissions. The “organic sulfur” found in samples also includes sulfide (nonpyritic) sulfur. Sulfite is not usually present in materials taken directly from ore deposits. There is more sulfite in the feed at the lower NO_x emission site than in the other feed from the other sites. This may reflect the return kiln dust and its sulfite content, which in turn may reflect the effect of oxygen upstream of the dust collector. If the available O₂ is lower in the kiln process gas this may also reduce low temperature formation of NO.

6.0 REFERENCES

- (1) US Geological Survey, Mineral Industry Survey – Cement, 2004
<http://minerals.usgs.gov/minerals/pubs/commodity/cement/>
- (2) American Society for Testing and Materials. *1998 Annual Book of ASTM Standards. ASTM Volume 04.01 Cement; Lime; Gypsum*. West Conshohocken, PA. 1998.
- (3) Shreve, R.N., and J.A. Brink. *Chemical Process Industries. Fourth Edition*. New York, NY. McGraw Hill, Inc. 1977. pp. 156-162.
- (4) Dorris, V.K., A. Gerson, and M.McIntyre. Portland Cement Association. *Cement and Concrete Reference Guide*. Skokie IL. 1997.
- (5) U.S. Environmental Protection Agency. *Alternative Control Techniques Document – NO_x Emissions from Cement Manufacturing*. EPA-453/R-94-004. Research Triangle Park, NC. March 1994.
- (6) Portland Cement Association. *U.S. and Canadian Portland Cement Industry: Plant Information Summary, December 31, 1998*. Skokie, IL. 214 pp.
- (7) Helmuth, R.A., F.M. Miller, T.R. O'Connor, and N.R. Greening. *Kirk-Othmer Encyclopedia of Chemical Technology. Vol. 5. Fourth Edition*. New York, NY. John Wiley & Sons, Inc. 1992. pp. 564-598.
- (8) Kosmatka, S.H. and W.C. Panarese. *Design and Control of Concrete Mixtures, Thirteenth Edition*. Portland Cement Association. Skokie, IL. 1994.
- (9) U.S. Environmental Protection Agency. *Compilation of Air Pollutant Emission Factors. AP-42. Fifth Edition. Volume I - Stationary Point and Area Sources*. Research Triangle Park, NC. January 1995. pp. 11.6-1 - 11.6-26.
- (10) Midwest Regional Planning Organization: Identification and Evaluation of Candidate Control Measures, prepared for The Lake Michigan Air Directors Consortium, April 2005
- (11) Weber, Dr. Paul, Heat Transfer in Rotary Kiln with due Regard to Cyclic Processes and Phase Formation, Bauverlag GmbH Wiesbaden, 1963
- (12) US Environmental Protection Agency, AP-42 – Compilation of Air Pollution Emissions Factors, Chapter 11.6 Portland Cement Manufacturing.
- (13) Nielsen, P.B., and O.L. Jepsen. *An Overview of the Formation of SO_x and NO_x in Various Pyroprocessing Systems*. Presented at the IEEE Cement Industry Technical Conference XXXII. Tarpon Springs, FL. May 22-24, 1990.
- (14) Zeldovich, J. The Oxidation of Nitrogen in Combustion and Explosions: Acta. Physiochem. 21(4). 1946.

- (15) U.S. Environmental Protection Agency. *Control Techniques for Nitrogen Oxide Emissions From Stationary Sources*. Publication AP-47. National Air Pollution Control Administration. Washington D.C. 1970.
- (16) Shreve, R.N., and J.A. Brink, Jr. *Chemical Process Industries*. New York, NY. Fourth Edition. McGraw Hill, Inc. 1977.
- (17) Portland Cement Association. *U.S. and Canadian Portland Cement Industry: Plant Information Summary*. December 31, 1998. 1999.
- (18) Portland Cement Association. Website: (<http://www.Portlandcement.org/env/enviro2.asp>). Accessed on July 11, 2000.
- (19) Hilovsky, R.J. *NO_x Reductions in the Portland Cement Industry With Conversion to Coal-Firing*. Presented at the 1977 U.S. EPA Emission Inventory/Factor Workshop. Raleigh, NC. September 13-15, 1977.
- (20) Gartner, E.M. *Nitrogenous Emissions From Cement Kiln Feeds: Portland Cement Association Interim Report on Project HM7140-4330*. Skokie, IL. June 1983.
- (21) Payne, R., T. Akiyama, and J.G. Witkamp. *Aspects of NO_x Formation and Reduction in Coal Fired Combustion Systems*. International Flame Research Foundation. Report NO_x F37/a/10. Ijmuiden, Netherlands. 1981.
- (22) Johansen, V., A. Egelov, and A. Eirikson. *Emission of NO_x and SO₂, From Cement Clinker Burning Installations*. Zement-KalkGips NO_x 10. 1986.
- (23) Scheuer, A. *Theoretische und betriebliche untersuchungen zur bildung und zum abbau von stickstoffmonoxid in zementdrehofenanlagen*. Schriftenreihe der Zementindustrie, Heft 49. 1987.
- 23(a) Huag N., Sauter G., Samant G., *Einsatz der High-Dust-SCR –Technologie in der Zementindustrie*, VDI-Vortrag, 2002.
- 23(b) Fischer K., Samant G., *Der Kat fürs Zementwerk*, UmweltMagazin, Dezember, 2002.
- 23(c) Anon, *Erste Anlage Zur Katalytischen Entstickung in Einem Zementwerk*, Umweltbundesamt, July, 2003.
- (23d) Midwest Regional Planning Organization: Identification and Evaluation of Candidate Control Measures, prepared for The Lake Michigan Air Directors Consortium, April 2005.
- (23e) C. Senior, et. al., SCR Deactivation Mechanisms Related to Alkali and Earth Elements, 2003 Conference on SCR and SNCR, NETL Publications, October 2003.
- (23f) Jens, B., et. al., Deactivation Mechanisms of SCR Catalysts During the Co-Combustion

- of Bio-Residues, 2003 Conference on SCR and SNCR, NETL Publications, October 2003.
- (23g) Vredenburg, L.H.J., et. al., The Effect of Co-Firing Large Amounts of Secondary Fuels on SCR Deactivation, 2003 Conference on SCR and SNCR, NETL Publications, October 2003.
 - (23h) Nielson, M. T., On the Relative Importance of SO₂ Oxidation to High Dust SCR DeNO_x Units, 2003 Conference on SCR and SNCR, NETL Publications, October 2003.
 - (23i) Linero, A. A., Letter to Sumter Cement Company, LLC, From Program Administrator, Bureau of Air Regulation, Florida Department of Environmental Protection, October 7, 2005.
 - (24) Haas, G.A. *Selective Noncatalytic Reduction (SNCR): Experience with the Exxon Thermal DeNO_x Process*. Presented at the NO_x Control V Conference. Council of Industrial Boiler Owners. Long Beach, CA. February 10-11, 1992.
 - (25) Bilan Lumbres, Holcim France; “Bilan environnement et sécurité 2004“.
 - (26) Lin, M.L., M.J. Knenlein, Fuel Tech Inc. “Cement Kiln NO_x Reduction Experience Using the NO_xOUT® Process,” proceedings of the 2000 International Joint Power Generation Conference, Miami Beach, FL, July 23-26, 2000.
 - (27) Joseph, G.E., and D.S. Beachler. *Student Manual, APTI Course 415 Control of Gaseous Emissions*. U.S. EPA, Air Pollution Training Institute. EPA 450/2-81-006. December 1981.
 - (28) Campbell, L.M., D.K. Stone, and G.S. Shareef. *Sourcebook: NO_x Control Technology Data*. U.S. EPA, Air and Energy Engineering Research Laboratory. EPA-600/2-91-029. July 1991.
 - (29) Siddiqi, A.A., and J.W. Tenini. Hydrocarbon Processing. 115-124. October 1981.
 - (30) Kokkinos, A., J.E. Cichanowicz, R.E. Hall, and C.B. Sedman. *Stationary Combustion NO_x Control: A Summary of the 1991 Symposium*. J. Air Waste Manage. Assoc. 1252. 1991.
 - (31) Teixeira, D. *Widening the Urea Temperature Window*. In Proceedings of 1991 Joint Symposium on Stationary Combustion NO_x Control. NTIS. 1991.
 - (32) Kupper, D., and Brentrup, L. *SNCR Technology for NO_x Reduction in the Cement Industry*. World Cement 23(3):4-9. March 1992.
 - (33) Penta Engineering Corporation *Report on NO_x Formation and Variability in Portland Cement Kiln Systems Potential Control Techniques and Their Feasibility and Cost Effectiveness*. Penta Project No. 971212. Prepared for the Portland Cement Association. PCA R&D Serial No. 2227. Skokie, IL. 1999.

- (34) Scheuer, A., *Non-catalytic reduction of NO with NH₃ in the cement burning process*. Zement-Kalk-Gips, No. 3/1990, Wiesbaden, Germany.
- (35) European Integrated Pollution Prevention and Control Bureau (EIPPCB). *Reference Document on Best Available Techniques in the Cement and Lime Manufacturing Industries*. World Trade Center, Seville, Spain. March 2000.
- (36) Yee, G.M. *Suggested Control Measure for the Control of Emissions of Oxides of Nitrogen from Cement Kilns*. Presented to the State of California, Air Resources Board for Discussion on October 21, 1981.
- (37) Sun, William H., Nalco Fuel Tech. *NO_xOUT[®] Process Demonstration on a Cement Kiln/Calcliner, Ash Grove Cement, Seattle Plant, Seattle, Washington*. October 28, 1993.
- (38) Sun, et. al. *Reduction of NO_x Emissions from Cement Kiln/ Calcliner through the Use of the NO_xOUT[®] Process*. Presented at the International Specialty Conference on Waste Combustion in Boilers and Industrial Furnaces. Kansas City, MO. April 1994.
- (39) Interoffice Correspondence from McAnany, L. to H. Knopf, H, LaFarge Corporation. October 26, 1998. re: Fuel Tech NO_xOUT[®] Testing.
- (40) PSM International Inc. and Penta Engineering Corp. *Review of Nalco Fuel Tech NO_xOUT[®] Program for Mid-Kiln Injection Urea to Reduce NO_x at the Colton California Plant of California Portland Cement Company*. October 26, 1994.
- (41) Biggs, H.O., Plant Manager, Mitsubishi Cement Corporation. *Biosolids Injection Technology: An Innovation in Cement Kiln NO_x Control*. (no date). Received during December 1999 trip report.
- (42) Shumway, D.C. *Tire Derived Fuel at Mitsubishi Cement Corporation*. (no date) Received during December 1999 site report.
- (43) McInnes, R., and M.B. von Wormer. *Cleaning Up NO_x Emissions*. Chem. Eng. 130-135. September 1990.
- (44) U.S. Environmental Protection Agency. *Summary of NO_x Control Technologies and Their Availability and Extent of Application*. EPA450/3-92-004. Research Triangle Park, NC 27711. February 1992.
- (45) Xeller, H. *Reducing NO_x Formation Using a Step Burner with Exit Gas Recycling from Preheater*. World Cement. 19(3):8492. March 1988.
- (46) Bauer, C. *PYRO-JET Burners to Reduce NO_x Emissions Current Developments and Practical Experience*. World Cement. 21(4). April 1990.
- (47) The ROTAFLAM Kiln Burner. Product Information Brochure. Procedair Industries, Combustion Division, Pillard Products, Louisville, KY. 1992
- (48) Vollan, P., and L. Klingbeil. *Modernization and Capacity Increase of Kiln Line No. 6 at the Dalen Plant, Norway*. World Cement. January 1988.

- (49) Wolter, A. *Fast Gas Trace Analysis Optimizes and Reduces the Emission of Pollutants in Cement Plants*. Zement-KalkGips No. 12, 1987.
- (50) Steinbiß, V.E., C. Bauer, and W. Breidenstein. *Current state of development of the PYRO-JET® burner*. VDZ Kongress. 1993.
- (51) Thomsen, K., L.S. Jensen, and F. Schomburg. *FLS-Fuller ILC-lowNO_x calciner commissioning and operation at Lone Star St. Cruz in California*. ZKG International. October 1998. pp. 542 - 550.
- (52) Letter and attachments from M.H. Vaccaro, Pillard Combustion Equipment and Control Systems, to G.J. Hawkins, Portland Cement Association, re: Low NO_x Rotaflam® burner, dated January 20, 1999.
- (53) PSM International, "Response to USEPA Comments, 13 September 1995, on the proposed alternative NO_x RACT for a Portland cement manufacturing plant located in Thomaston, Maine and owned by Dragon Products Company," Jan 31, 1996.
- (54) Renfrew, S, Process Engineer, RMC Lonestar. *Calciner modification highly effective in meeting Northern California Plant's alkali reduction and emission control requirements*. no date.
- (55) Portland Cement Association and American Portland Cement Alliance. *Results of the NO_x Control Presurvey Results*. January 2000.
- (56) Memorandum from Battye, R.E., and S. Edgerton, EC/R Incorporated, Chapel Hill, NC, to B. Neuffer, U.S. EPA, RTP, NC. *Summary of February 4, 2000 teleconference to discuss results of NO_x Control Presurvey Results*. February 11, 2000.
- (57) Portland Cement Association. *A New Stone Age: The Making of Portland Cement*. Skokie, IL. 1992. pg. 4.
- (58) Cadence Environmental Energy, Inc. www.cadencerecycling.com.
- (59) Battye, R., and S. Edgerton, EC/R Incorporated. "December 2, 1999 Trip Report to Mitsubishi Cement Corporation, Cushenbury Plant." Lucerne Valley, CA. Submitted to Dave Sanders, US EPA, under contract No. 68-D-98-026, work assignment No. 2-28. August 31, 2000.
- (60) Shumway, D.C. "Tire Derived Fuel at Mitsubishi Cement Corporation." Received during December 2, 1999 visit to Mitsubishi.
- (61) Shumway, D.C. *Mitsubishi Cement Corporation's Cushenbury Plant* presented at the IEEE West Coast Cement Industry Conference. Victorville, CA. Oct 1995.
- (62) Rother, R. and D. Kupper. *Staged Fuel Supply - An Effective Way of Reducing NO_x Emissions*. Zement-Kalk-Gips. No. 9. 1989.

- (63) Nielsen, P.B., and O.L. Jepsen. *An Overview of the Formation of SO_x and NO_x In Various Pyroprocessing Systems*. Presented at the IEEE Cement Industry Technical Conference XXXII. Tarpon Springs, FL. May 22-24, 1990.
- (64) Facsimile from Bennett, J., California Portland Cement Company, to Damle, A.S., Research Triangle Institute. August 4, 1993. Process modifications in cement kilns.
- (65) Benoit, M.R., E.R. Hansen, and T.J. Reese. *Method for Energy Recovery from Containerized Hazardous Waste*. U.S. Patent No. 4974529. December 1990.
- (66) Walquist, C., Cadence Environmental Energy. "Cadence system leads to fall in NO_x emissions," *World Cement*, Dec 1997, pp. 26, 27.
- (67) Cadence Environmental Energy and Ash Grove Cement. "Mid-Kiln Fuel Entry Benefits," section 3 of the report, *Emission, Reduction, Technology: Resource Conservation & Recovery*. (no date).
- (68) Hansen, E.R. *New Way to Burn Hazardous Waste*. Rock Products. April 1990.
- (69) Letter from Edgerton, S. and T. Stobert, EC/R Inc., to Bill Neuffer, EPA, Feb 8, 2000. Minutes from Dec 16, 1999 meeting with representatives from EPA and Cadence.
- (70) Texas Natural Resources Conservation Commission. A list of permitted NO_x levels for cement plants in the state, CEMS data as reported by the facilities for 1994 - 1999, and information on the control technology in use at each facility.
- (71) May, M. and L. Walters, Jr. "Low NO_x & Tire-derived Fuel for the Reduction of NO_x from the Portland Cement Manufacturing Process." *Cement Americas*, August 1999, pp. 10-1.
- (72) Letter and attachments from Bramble, Kim, Cadence, to Bill Neuffer, USEPA, re: NO_x Emission Reducing Technology, dated Feb 14, 2000.
- (73) Radian Corporation, "MDE Air Permit Test Report for Lehigh Portland Cement Company, Union Bridge, Maryland Facility," January 1996.
- (74) Email transmission from Hawkins, G., PCA, Skokie, IL to B. Neuffer, U.S. EPA. Results of PCA Survey - Preliminary NO_x Control Technology Questionnaire. January 2000.
- (74a) The BOC Group-LoTO_xTM.
http://www.boc.com/markets/environment/bulk_gasses/lotox.asp.
- (74b) "Pilot Demonstration Testing of LoTO_xTM Report" EPRI: Pilot Demonstration Testing of LoTO_xTM. http://www.epri.com/OrderableItemDesc.asp?product_id=0000000.
- (74c) "Innovative Clean Air Technology Grant Report Low Temperature Oxidation System Demonstration." RSR Quementco, Inc., City of Industry, California. BOC Process Gas Solutions, 575 Mountain Avenue Murray Hill, NJ 07974. Event: 2000-12-08

Demonstration for Low Temperature Oxidation.
<http://www.arb.ca.gov/research/icat/projects/boc.htm>.

- (74d) “Status of Multi-Pollutant Process Development: LoTOx/BOC, GSA/FLS, Pahlmanite Cost Projections Report”. EPRI: Status of Multi-Pollutant Process Development: LoTOx/BO... http://www.epri.com/OrderableItemDesc.asp?product_id=0000000.
- (74e) “Multi-Pollutant Control Technologies: cost Projections of LoTOx/BOC, GSA/FLS, and Pahlmanite.” EPRI: Fossil Steam Plants & Combustion Turbines>Integrated En... <http://www.epri.com/targetHigh.asp?program=262194&value=03...>
- (74f) “Status and Performance of Best Available Control Technologies Report” EPRI: Status and Performance of Best Available Control Technologies.
http://www.epri.com/OrderableItemDesc.asp?product_id=0000000/.
- (74g) “A Report on the Application of Low Temperature Oxidation for Control of NOx Emissions.” R. Ferrell, N. Suchak, S.C. Hwang, J. Tsens, R. Kelton. The BOC Group, Inc., Process Gas Solutions 575 Mountain Ave., Murray Hill, NH 07974. W. Goss, Beaumont Environmental Systems 108 Lintel Drive, McMurray, PA 15317. R. Lutwen, SFT, Inc. 6629 W. Central Ave., Toledo, OH 43617
- (74h) “Low Temperature Oxidation System Demonstration at RSR/Quemetco, Inc. City of Industry, California. <http://www.arb.ca.gov/research/icat/projects/boc.htm>.
- (74i) “LoTOX™ Technology Demonstration at Marathon Ashland Petroleum LLC’s Refinery in Texas City, TX.” Marathon Ashland Petroleum LLC, Jeffrey Sexton, 539 South Main St., Findlay, OH 45840. Belco Technologies Corporation, Nicholas Confuorto, 7 Entin Rd., Parsippany, NJ 07054. BOC Process Gas Solutions, Michael Barrasso/Naresh Suchak, 575 Mountain Avenue, Murray Hill, NJ 07974.
- (74j) “Applications and Economics of Low Temperature Oxidation NOx Control.” BOC Gases 575 Mountain Avenue Murray Hill, NJ 07974. M.H. Anderson, R.J. Ferrell, Dr. S.C. Hwang, Dr. N. Suchak, Dr. James Tseng, R. Kelton
- (74k) “Application of Low Temperature Oxidation for NOx Emissions Control on a Lead Recovery Furnace.” R. Ferrell RJF Consultants 196 Hollister Avenue, Rutherford, NJ 07070. Dr. N. Suchak, R. Kelton The BOC Group, Inc., Process Gas Solutions 575 Mountain Ave., Murray Hill, NJ 07974. H. Hine, RSR Corporation, Dallas, TX M. Vondersaar, Quemetco, Inc., City of Industry CA. Shyam Nadkarni, 144 Woodmere Blvd., Woodmere, NY 11598.
- (74l) “New Process and Equipment for Waste Minimization: Conversion of Nitrogen Oxide (NOx) Scrubber Liquor to Fertilizer.” Conversion of Nitrogen Oxide (NOx) Scrubber Liquor to Fertilizer. http://rtreport.ksc.nasa.gov/techreports/95_report/envirnof/envirno0.
- (74m) “Using Non-Thermal Plasma to Control Air Pollutants.” EPA-456/R-05-001. The Clean Air Technology Center (CATC). U.S. Environmental Protection Agency (E143-03). Research Triangle Park, North Carolina 27711.

- (74n) "ETV for Add-On NO_x APT Update." Douglas VanOsdell.
- (74o) "Nitrogen Oxides (NO_x) Abatement With Hydrogen Peroxide." Reference Library/Applications: Industrial Wastewater
<http://www.h2o2.com/applications/industrialwastewater/nox.html>
- (74p) "Kinetics of NO_x Absorption into Aqueous Solutions of Oxone." Kinetics of NO_x Absorption into Aqueous Solutions of Oxone.
<http://aiche.confex.com/aiche/2005/techprogram/P15564.HTM>
- (75) Helmuth, R.A., F.M. Miller, T.R. O'Connor, and N.R. Greening. *Kirk-Othmer Encyclopedia of Chemical Technology. Vol. 5. Third Edition*. New York, NY. John Wiley & Sons, Inc. 1979. pp. 163-193.
- (76) Yee, G.M. *Suggested Control Measure for the Control of Emissions of Oxides of Nitrogen from Cement Kilns*. Presented to the State of California, Air Resources Board for Discussion on October 21, 1981.
- (77) Miller, F.M. *Oxides of Nitrogen*. GTC Presentation, Kansas City, MO, September 20, 1977.
- (78) Hansen, E.R., "The Use of Carbon Monoxide and Other Gases for Process Control," 27th IEEE Cement Industry Technical Conference Proceedings, May 1985.
- (79) Mehta, P.K. *Energy, Resources and the Environment - A Review of the U.S. Cement Industry*. World Cement Technology. July/August 1978.
- (80) Andover Technology Partners. *NO_x Reduction from Cement Kilns Using the CemStar Process*, Evaluation of CemStar Technology - Final Report to Texas Industries. Dallas, Texas. April 18, 2000.
- (81) Battye, R., and S. Edgerton, EC/R Incorporated. "December 2, 1999 Trip Report to Texas Industries (TXI) Riverside Cement, Oro Grande facility." Oro Grande, CA. Submitted to Dave Sanders, US EPA, under contract No. 68-D-98-026, work assignment No. 2-28. August 31, 2000.
- (82) En-tellect Environmental Services, Inc., "Evaluation of the Effects of the CemStar Process on a Wet Process Cement Kiln," (no date, but includes data for July-Sept 1999).
- (83) Hilovsky, R.J. *NO_x Reductions in the Portland Cement Industry With Conversion To Coal-Firing*: Presented at the 1977 U.S. EPA Emission Inventory/Factor Workshop. Raleigh, NC. September 13-15, 1977.
- (84) Radian Canada, Inc. *Assessment of NO_x Emission Control Technologies for Cement and Lime Kilns*. Radian Report No. 714-061-01. Prepared for Environment Canada, Contract No. K2035-3-7044. October 1994. Pg.iv.

- (85) Portland Cement Association. *U.S. and Canadian Portland Cement Industry Plant Information Summary*. Skokie, IL. December 31, 1998.
- (86) Penta Engineering Corporation *Report on NO_x Formation and Variability in Portland Cement Kiln Systems Potential Control Techniques and Their Feasibility and Cost Effectiveness*. Penta Project No. 971212. Prepared for the Portland Cement Association. PCA R&D Serial No. 2227. Skokie, IL. 1999.
- (87) Comments on *Alternative Control Techniques Document - NO_x Emissions from Cement Manufacturing* submitted by Greer, W.L. to William Neuffer, U.S. EPA through T.B. Carter, APCA. October 27, 1999.
- (88) Worrell, Ernst and Galitsky, Christina, “Energy Efficiency Improvement Opportunities for Cement Making An ENERGY STAR Guide for Energy and Plant Managers”, Energy Analysis Department, Environmental Energy Technologies Division., Ernest Orlando Lawrence Berkeley National Laboratory, University of California, January 2004.
- (89) Birch, E., “Energy Savings in Cement Kiln Systems” Energy Efficiency in the Cement Industry, London, England, 1990.
- (90) Fujimoto, S., “Modern Technology Impact on Power Usage in Cement Plants, 1994.
- (91) Hendriks, C.A., E. Worrell, D. de Jager, K. Blok, and P. Riemer. 1998. Emission Reduction of Greenhouse Gases from the Cement Industry Lawrence Berkeley National Laboratory, Berkeley, California. IEA.
- (92) COWIconsult, Internahsauon and the External Cost of Transport Lyngby, Denmark Danish Ministry of Energy, EFP-91, 1993.
- (93) Young, Gerald L. “Review of NO_x Control Technologies for Cement Kilns, Associated Costs and NO_x Reduction Efficiencies, 2002.
- (94) COWIconsult, Internahsauon and the External Cost of Transport Lyngby, Denmark Danish Ministry of Energy, EFP-91, 1993.
- (95) Jaccard and Willis Energy Services, “Industrial Energy End-Use Analysis and. Conservation Potential in Six Major Industries in Canada, 1996.
- (96) Venkateswaran, SR and HE Lowitt, “The US Cement Industry: an Energy Perspective, DOE, Washington, DC, USA, 1988.
- (97) Anonymous, “Cement Plant Modernization in Central Europe,” World Cement, November 1994.
- (98) Vleuten, Cement in Development: Energy and Environment. Petten, Netherlands: Netherlands Energy, 1994.
- (99) van Oss, US Geological Survey, Communication with authors (see reference 88) , 1999.

- (100) Nisbet, M., 1996. "The Effects of New Climate change Commitments on Energy Intensive Industries, The Cement Industry", 1996.

Attachment A
ERG SUMMARY OF EPA 2000 NO_x CONTROLS FOR CEMENT KILNS

Attachment A – Table A-2

Table A-1. Summary of EPA Reported NO_x Control Technologies for Cement Kilns – EPA 2000

NO _x Control Strategies		Applicability	NO _x Reduction Efficiency (%)	Estimated Costs	Number of Installations
Process modifications	Excess air and temperature optimization (using CO and O ₂ CEMS and feedback control)	All kiln types	15 ^a	Capital cost = ~\$750,000 ^s	Unknown
	Reduce alkali content of feed where feasible	All kiln types	Not available	Not available	Unknown
	CemStar (addition of steel slag)	All kiln types although higher NO _x reductions expected from wet and long-dry kilns due to greater heat input offsets	9 - 60 ^b	Capital cost = \$200,000 - \$500,000 ^t Annual costs are highly site-specific (e.g., slag injection rate, potential cost savings due to increased production)	11
	Fuel switching (natural gas to coal)	All kiln types	70 ^c	Not available	~ 87% of existing kilns use coal
	Improving thermal efficiency	All kiln types	Not available	Not available	Unknown
Combustion modification	Staged air combustion - staged fuel combustion	All kiln types (most effective with indirect fired kilns)	Not available	Not available	Unknown
	Staged air combustion - flue gas recirculation	May not be suitable for cement kilns. Incorporation of FGR in a cement kiln also results in somewhat increased power consumption and reduced kiln output.	Not available	Not available	Unknown
	Staged air combustion - flue gas recirculation w/low-NO _x burner		15 - 38 ^d	Not available	Unknown
	Staged air combustion - Low-NO _x burner	All kiln types (burners that use 5-7% excess air are only for indirect-fired kilns)	44 ^e 15 - 33 ^f 23 - 47 ^g 14 ^h	Capital cost = \$511,000 - \$966,000 ^u Annual cost = \$136,000 - \$204,000 ^u	~ 22 existing kilns use low-NO _x burners

Attachment A – Tables A-1 (continued)

NO _x Control Strategies		Applicability	NO _x Reduction Efficiency (%)	Estimated Costs	Number of Installations
Combustion modification (cont.)	Staged fuel combustion - Tire-derived fuel (TDF)	All kiln types	30 - 40 ⁱ		Unknown. Approximately 53,300,000 tires are burned in cement kilns annually http://www.epa.gov/epaoswer/non-hw/muncpl/tires/tdf.htm#cement
	Staged fuel combustion - Low-NO _x precalciner	Not applicable to preheater kilns that fire fuel in the riser	≤46 ^j	Not available	Unknown
	Staged fuel combustion - Mid-kiln firing	Wet and long-dry kilns	38 ^k 11 - 55 ^l 28 - 59 ^m	Capital cost = ~ \$3,000,000 ^v Annual cost = (\$370,000) - \$189,000 ^v	21 long kilns (US), 40 kilns (worldwide)
Post-formation removal	Selective catalytic reduction (SCR)	No cement kilns had SCR at the time of the EPA Study prior to 2000.		Not available in 2000.	No installations were reported on cement kilns in EPA 2000.
	Selective non-catalytic reduction (SNCR)	Best application is for preheater/precalciner kilns. Generally not applicable to long-dry or wet kilns	71 -98 ⁿ 10-20 ^o	Not available	2 kilns (US), 18 in Europe
	Biosolids (SNCR)	Preheater/precalciner kilns	Not available	Capital cost = \$240,000 ^w Annual cost = (\$322,000) ^w	Unknown
	NO _x OUT (SNCR)	Preheater/precalciner kilns	> 50 - 90 ^p 10 - 20 ^q 46 - 53 ^r	Capital cost = ~\$1,200,000 ^x Annual cost = \$560,000 - \$2,000,000 ^x	None
	Low Temperature Oxidation (LoTOx TM , Hydrogen Peroxide, OXONE (Dupont) & Sodium Acetate)	Oxidation technologies were not discussed or considered in the EPA 2000 report.	Not considered	Not considered	Oxidation technologies were not discussed or considered in the EPA 2000 report.

^aResults based on experimental test on one kiln.

^bResults derived from short- and long-term tests on two different kiln types.

^cResults based on emission tests of dry kilns.

^dResults based on a single 1988 study. The percent reduction depends on degree of flue gas recirculation.

^eResults based on emission tests of a preheater/precalciner kiln.

^fResults based on emission tests of five kilns.

^gResults based on emission tests of four kilns.

Attachment A – Tables A-1 (continued)

^hEmission test of one kiln.

ⁱResults based on tests conducted at one California facility.

^jResults based on a test conducted by the Portland Cement Association.

^kResults based on one study.

^lResults based on testing of seven dry kilns.

^mResults based on testing of three wet kilns.

ⁿBased on emission tests of a preheater/precalciner kiln at one facility.

^oResults based on emission test at one facility

^pResults based on emission tests of a single kiln.

^qResults based on a emission tests of a single kiln (operating conditions during most of the test were unstable).

^rResults based on emission test of two kilns.

^sEstimate for a commercially available process control system.

^tCost estimates obtained from Texas Industries (TXI).

^uCosts derived for retrofitting low-NO_x burners to eight model kilns with clinker production capacities ranging from 25 to 150 tons of clinker per hour.

^vCosts derived for retrofitting low-NO_x burners to four model kilns with clinker production capacities ranging from 25 to 50 tons of clinker per hour. Annual costs reflect the fuel credit associated with using tire-derived fuel.

^wCosts based on a clinker production rate of 215 tons per hour.

^xCosts based on two preheater/precalciner kilns with a clinker production rates of 92 tons per hour and 133 tons per hour.

**ATTACHMENT B
SAMPLING PLAN**

Sample Acquisition and Handling

Clean, clear, pre-labeled, one (1) liter sample bottles were shipped to each Kiln site on August 23, 2005 via Federal Express. The nine (9) samples returned on August 25 in good condition from Texas Industries Inc. included three wet slurry, three dry powder and three slag samples. The six (6) samples returned from Ash Grove Cement on August 26 included three (3) wet slurry and (3) slag samples. The 6 samples returned from Holcium on August 31 included three (3) samples from line 1 and 3 samples from line 2.

All were samples returned to ERG's analytical laboratory with chain of custody and security seals. ERG consulted with three cement kiln experts, F. MacGregor Miller, Gabriel Miller, and David Gossman on the analyses required to determine key features of the kiln feed chemistry important to NO_x emissions and control. Recommendations were sought from the experts on laboratories experienced in each analysis. Three laboratories were ultimately selected on the basis of expertise and price. Table 1 summarizes the analyses requested for each sample.

ERG repackaged samples for distribution to the specialty analysis laboratories scheduled to perform feed material composition analysis. Repackaged samples were give unique identification numbers to keep Kiln identity anonymous to the analysis laboratories.

Table B-1. Feed Chemical Composition

Plant Name	Samples Received	Sample Type	Total Sulfur	Sulfate	Sulfite	Pyritic Sulfur	Organic Sulfur	Chloride	Nitrogen (TKN)	VOCs
Texas Industries Inc (TXI)	3	Wet Slurry	X	X	X	X	X	X	X	X
Texas Industries Inc (TXI)	3	Dry Powder	X	X	X	X	X	X	X	X
Texas Industries Inc (TXI)	3	Slag	X	X	X	X	X	X	X	X
Holcim US Inc	0	Dry Power Line 1	X	X	X	X	X	X	X	X
Holcim US Inc	0	Dry Power Line 2	X	X	X	X	X	X	X	X
Ash Grove Cement Inc	3	Wet Slurry	X	X	X	X	X	X	X	X
Ash Grove Cement Inc	3	Slag	X	X	X	X	X	X	X	X

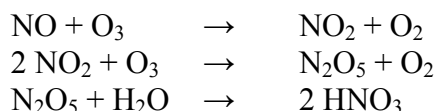
ATTACHMENT C
ERG Report on LoTOxTM Application to Refineries

ERG Report - Refinery Application of Low Temperature Oxidation Emissions Controls

LoTOx™

LoTOx™ is a trademark of the BOC Group Inc. for an end-of-pipe process that uses ozone to oxidize insoluble species of NO_x, such as NO and NO₂, to highly soluble species, primarily N₂O₅. N₂O₅ then reacts with moisture in the flue gas to form nitric acid (HNO₃) and is removed from the gas in a wet gas scrubber. LoTOx™ is a developing technology for NO_x control, and there are currently only about three commercial applications of LoTOx™. Another three installations are planned in the next two years. LoTOx™ has been demonstrated using slipstream testing at ten types of facilities, including a smelting plant, a glass furnace, a lead furnace, a petroleum coke and high sulfur coal fired boiler, a chemical plant, a steel pickling bath process, a gas-fired boiler, a composite fuel fired boiler, a petroleum refinery fluid catalytic cracking unit (FCCU), and a lignite-fired boiler. No cement plants have tested LoTOx™.

In the LoTOx™ process, ozone is formed from oxygen using a corona-discharge ozone generator. The resulting concentration of ozone is between 7 and 15 weight percent (1). The ozone/oxygen mixture is injected into the flue gas stream as it enters either a wet gas scrubber or a reaction vessel adjacent to a wet gas scrubber. The ratio of ozone to NO_x is 0.2-2.8:1, and varies with factors such as flue gas temperature and residence time. The principal reactions for NO_x oxidation are:



The maximum temperature for the oxidation reactions is 325 °F (163 °C), while the optimal temperature is generally less than 300 °F (149 °C). The NO_x oxidation reactions become unstable over 325 °F. Trials at a coal-fired power plant and a steel pickling process found the optimal temperature was in the range of 160 to 250 °F (1). A trial at a battery lead recovery furnace found the optimal temperature was 175 °F or less, although the temperature could be increased up to 225 °F without sacrificing NO_x removal, but at the cost of increased ozone demand (2). A trial at Marathon Ashland Petroleum's (MAP) Texas City refinery FCCU found the optimal temperature was 140 to 150 °F (3). These temperatures are lower than typical cement kiln flue gas temperatures. In addition to cooling using heat recovery systems, quenching with water is typically used to lower the gas temperature to the adiabatic saturation temperature.

After NO_x is oxidized to N₂O₅, it is absorbed from the flue gas by water spray in a wet gas scrubber. The relative solubility of N₂O₅ compared to other flue gas species is presented below.

Relative Solubility of Flue Gas Components

Species	Relative Solubility at 25 °C
NO	1
NO ₂	20
SO ₂	2000
N ₂ O ₅	>>2000
HNO ₃	Mixes with water in all proportions

Ferrell 2003, p. 4

N₂O₅ reacts immediately and irreversibly with water to form nitric acid. The nitric acid then is neutralized with caustic or lime in the scrubber liquor to form sodium or calcium nitrates.

Potential Advantages of LoTOxTM

The potential advantages of LoTOxTM are as follows.

LoTOxTM can provide a high degree of NO_x removal. Based on slipstream testing, 70 to 90 percent NO_x removal is typical, with greater than 95 percent NO_x removal achievable.

LoTOxTM can respond quickly to variable NO_x emissions. Since ozone is produced on demand, changes in NO_x load can be met without loss of NO_x removal efficiency. Swings in NO_x concentration by 100 percent or more over the course of minutes have been accommodated using combined feed-forward/feed-back control schemes (Ferrell 2000, pp. 8-9; Ferrell 2003, pp. 13-14). Although most LoTOxTM trials have been for combustion processes (90:10 NO to NO₂ ratio), the steel pickling process had variable NO to NO₂ ratios, with NO₂ sometimes higher than NO. Ozone production was decreased since less ozone was required to oxidize NO_x to N₂O₅, while NO_x removal was maintained above 95 percent (1).

LoTOxTM does not emit excess reactant. Unlike SCR and SNCR, which can emit excess ammonia, the ozone that does not react with NO_x in the LoTOxTM process is scavenged by sulfite in the scrubber solution. A trial at a lead furnace examined the potential for unreacted ozone to be emitted from the process. It was found that the ozone addition had to be increased by a factor of eight over what was required for NO_x removal to cause 0.6 ppm of ozone to be measured in the stack gas (2).

LoTOxTM is highly selective for NO_x. Although ozone can oxidize SO₂ and CO, the presence of SO₂ and CO does not impact NO_x removal. This is due to the faster reaction rates for NO_x oxidation compared to oxidation of other gas species.

Relative Reaction Rates of Flue Gas Components with Ozone

Species	Relative Reaction Rates
$\text{NO} + \text{O}_3 \rightarrow \text{NO}_2 + \text{O}_2$	62,500
$2 \text{NO}_2 + \text{O}_3 \rightarrow \text{N}_2\text{O}_5 + \text{O}_2$	125
$\text{SO}_2 + \text{O}_3 \rightarrow \text{SO}_3 + \text{O}_2$	5
$\text{CO} + \text{O}_3 \rightarrow \text{CO}_2 + \text{O}_2$	1

Ferrell 2003, p. 3

LoTOx™ does not interfere with other pollution control technologies. The trial at MAP's Texas City refinery FCCU indicated LoTOx™ does not have a negative impact on SO₂ scrubbing efficiency. The scrubber maintained SO₂ removal in excess of 99 percent during the LoTOx™ trial (3).

Areas of Concern

Wet Gas Scrubber Required

A wet gas scrubber is necessary to take advantage of the increased solubility of N₂O₅ over NO and NO₂. For cement plants with an existing wet gas scrubber for SO₂ and particulate matter removal, LoTOx™ can be installed as an upstream retrofit. For plants that do not require a scrubber for SO₂ or particulate matter removal, installing a scrubber for NO_x removal only may not be cost effective.

Gas Temperature

Cement kiln flue gases typically have temperatures greater than the LoTOx™ maximum temperature of 325 °F. If the flue gas temperature is greater than 325 °F after useful heat has been recovered, quenching with water is required prior to ozone injection. BOC indicates that water quenching can be used on gas streams with temperatures up to 650 °F and moisture contents of 30 to 35 percent.

Nitrates in Wastewater

Sodium nitrate is typically the primary byproduct of the LoTOx™ process. This may be a concern for treatment and/or discharge of the wastewater. MAP examined the possible problems of increased nitrates in the study at the Texas City refinery (3). Regarding sodium toxicity, MAP found that the contribution of sodium nitrate from LoTOx™ was small compared to sodium sulfate from SO₂ scrubbing. Regarding wastewater treatment impacts, monovalent cations, such as sodium, can have a destabilizing effect on bioflocculation by displacing divalent cations, such as calcium or magnesium. This can lead to decreased biofloc settling and increased suspended solids. This problem does not occur if the monovalent to divalent cation ratio is maintained at 2:1 or less (by addition of divalent cations if necessary). In addition, nitrogen gas produced by denitrification in the secondary clarifier sludge bed can cause the bed to rise, increasing suspended solids. In this case, a holding tank can be installed to shift the denitrification reactions out of the secondary clarifier.

Cost

BOC indicates NO_x removal of 70 percent or greater must be required for LoTOx™ to be cost effective. In ERG's experience, the estimated cost effectiveness for LoTOx™ installations at refineries has ranged from approximately 2,500 to 10,000 dollars per ton of NO_x (as NO₂) removed. In general, the cost per ton of NO_x removed was lower for units with high NO_x removal (greater than 85 percent), due to economy of scale. Similarly, the annual operating cost was at least 50 percent of the total annualized cost for those units with the lowest cost per ton of NO_x removed. The costs of oxygen and electricity for the ozone generator accounted for 80 to 90 percent of the annual operating costs.

For a 200 MW coal-fired power plant, BOC estimated the cost to be only 1,696 dollars per ton of NO_x removed (1). This application was designed for 95 percent NO_x removal, and the annual mass of NO_x removed was 4 to 46 times larger than the refinery applications.

References Cited

- (1) (Ferrell 2000). Ferrell, R., M.H. Anderson, S.C. Hwang, N.J. Suchak, R. Kelton, J.T. Tseng. "Applications and Economics of Low Temperature Oxidation NO_x Control." Paper presented at Power-Gen 2000, November 14, 2000, Orlando, FL.
- (2) (Ferrell 2003). Ferrell, R., N. Suchak, R. Kelton, H. Hine, Shyam Nadkarni. "Application of Low Temperature Oxidation for NO_x Emissions Control on a Lead Recovery Furnace." Paper presented at ACE 2003, June 22-26, 2003, San Diego, CA.
- (3) (Sexton 2004). Sexton, J., N. Confuorto, M. Barrasso, N. Suchak. "LoTOx™ Technology Demonstration at Marathon Ashland Petroleum LLC's Refinery in Texas City, Texas." Paper presented at NPRA Annual Meeting, March 21-23, 2004, San Antonio, TX.

ATTACHMENT D
SUMMARY OF CURRENT US REGULATIONS FOR NO_x

Table D-1. Summary of US NO_x Control Regulations for Cement Kilns – EPA 2004

State	Effective Date	Source Type	Description	Emission Limit	Applicability	Avg. Time	Test/CEM	Rule
NY	5/1/03	NO _x Budget Trading Program	EGUs ≥ 15 MW; non EGUs ≥ 250mmBtu/hr; Portland Cement Plants ≥ 250mmBTU/hr	Allowances & Trading Program	All statewide	Ozone season	CEM	Part 204
	05/31/95	Portland cement kilns	Sources with PTE 25 TPY in NYC and lower Orange county metro areas; PTE 100 TPY elsewhere in State	Analysis of RACT controls; select control; NY approves RACT emission limit & submits to EPA as a SIP revision				Part 220 RACT
MD	11/24/03	Cement kilns	Capacity no more than 600,000 TPY	0.5 tons per hour		30 day rolling avg	CEM	COMAR 26.11.09.08
	11/24/03		Capacity greater than 600,000 TPY	0.9 tons per hour		30 day rolling avg	CEM	COMAR 26.11.09.08
	05/1/03	Non-trading source	Cement Kilns	Long wet-6.0 lb./T of clinker; long dry-5.1; preheater/precalciner or pre-calciner-2.8			CEM	26.11.29.15
PA	Proposed	Cement	Kilns Long dry -12 TPH; Long wet -10TPH; Preheater-16TPH ; Precalciner & PH/PC-22 TPH	LNB or mid-kiln firing or alt. that achieves 30% reduction	Statewide	Season	CEM	Chapter 145-Subchapter C-proposed
AL	04/06/01	Cement kilns	Process rates at least(TPH)-long dry-12; long wet-10; preheater-16; PH/PC-22	LNB or mid-kiln firing or equivalent controls	Various counties	Ozone season		335-3-8-.01
KY	08/15/01	Cement kilns	16; PH/PC-22	6.6 lbs./T of clinker	Statewide	30 day rolling avg-ozone season	CEM	401 KAR 51:170

Table D-1. Summary of US NO_x Control Regulations for Cement Kilns – EPA 2004

SC	05/31/04	Cement kilns Early Action Compact (EAC)	Process rates at least(TPH)-long dry-12;long wet-10;preheater-16;PH/PC-22 or NO _x >1 TPD	LNB or mid-kiln firing or similar controls	All Statewide	ozone season	CEM or annual source test	61-62.99 Subpart B
			Cement kilns Process rates(TPH) at least-long dry-12;long wet-10;preheater-16;PH/PC-22	LNB or equivalent capable of achieving 30% reduction				Reg 61-62.5;Standard No.5.2
TN	05/31/04	Cement kilns		LNB or mid-kiln firing or similar controls or RACT	Statewide	ozone season		1200-3-27-.04
IL	05/30/04	Cement kilns	Long dry kilns at least 12 TPH	5.1 lb./T or 30% reduction or LNB or mid kiln firing	Statewide	Ozone season	Annual stack test	Part 217; Subpart T
	05/30/04	Cement kilns	Long wet kilns at least 10 TPH	6.0 lb./T or same as above	Statewide	Ozone season	Annual stack test	Part 217; Subpart T
	05/30/04	Cement kilns	Preheater kilns at least 16 TPH	3.8 lb./T or same as above	Statewide	Ozone season	Annual stack test	Part 217; Subpart T
	05/30/04	Cement kilns	Preheater/precalciner kilns at least 22 TPH	2.8 lb./T or same as above	Statewide Clark, Floyd Cos;may avg among plants statewide	Ozone season	Annual stack test	Part 217; Subpart T
IN	08/04/97	Emission limits	Cement kilns - long dry-at least 20 TPH	Daily – 10.8 lb./T; Rolling 30 day - 6.0 lb./T	under same owner	ozone season	CEM	326 IAC 10-1-4
	08/04/97		Preheater kilns at least 20 TPH	Daily - 5.9 lb./T; Rolling 30 day – 4.4 lb./T	Same as above	ozone season	CEM	326 IAC 10-1-4

Table D-1. Summary of US NO_x Control Regulations for Cement Kilns – EPA 2004

MI	03/01/04	Reduction - certain categories	Cement kilns - long dry at least 12 TPH; long wet- 10 TPH	5.1, 6.0 lb./T or LNB or mid kiln firing or 30%control	Statewide	ozone season	CEM unless LNB or mid-kiln	326 IAC 10-3
	03/01/04		Preheater kilns at least 16 TPH;precalciner and PH/PC - 22 TPH	3.8, 2.8 lb./T; same as above	Statewide	ozone season	same as above	326 IAC 10-3
	12/04/02	Non SIP Call	Cement kilns Long dry -12 TPH; Long wet - 10TPH;Preheater-16TPH	LNB or mid-kiln or 25% red from 1995	Statewide	ozone season		336.1801
	12/04/02	Cement kilns		LNB or mid-kiln or long wet - 6.0 lbs./T; long dry - 5.1 lbs./T	Fine grid	ozone season	Annual stack test or CEM	336.1816
	12/04/02	Cement kilns	Precalciner & PH/PC-22 TPH Long dry -12 TPH; Long wet - 10TPH;Preheater-16TPH	Preheater - 3.8 Lb/T; PH/PC-2.8 lb./T or 30%red	Fine grid	ozone season		336.1816
OH	04/30/04	Cement kilns		LNB or mid-kiln firing or similar controls	Statewide	ozone season	Annual stack test or CEM	3745-14-11
	04/30/04	Cement kilns	Precalciner & PH/PC-22 TPH	LNB or mid-kiln firing or similar controls	Statewide	ozone season	Annual stack test or CEM	3745-14-11
TX *	03/27/03	Cement kilns	Wet kilns	6.0 lb./T of clinker	Bexar, Hays, Comal and McLennan Cos	30 day rolling avg	CEM or PEMS	Chap.117; Sec.265
	03/27/03	Cement kilns	Wet kilns	4.0 lb./T	Ellis Co.	30 day rolling avg	CEM or PEMS	Chap.117; Sec.265
	03/27/03	Cement kilns	Long dry kilns	5.1 lb./T	Bexar, Hays, Comal and McLennan Counties	30 day rolling avg	CEM or PEMS	Chap.117; Sec.265

Table D-1. Summary of US NO_x Control Regulations for Cement Kilns – EPA 2004

	03/27/03	Cement kilns	Preheater kilns	3.8 lb./T	Above counties	30 day rolling avg	CEM or PEMS	Chap.117; Sec.265
	03/27/03	Cement kilns	Preheater/precalciner or precalciner kilns	2.8 lb./T	Above counties	30 day rolling avg	CEM or PEMS	Chap.117; Sec.265
						24 cons. Hrs/30 consecutive days		
SCAQMD	07/01/86	Cement kilns	Any gray cement kiln	11.6 lbs./T; 6.4 lbs./T	Districtwide			Rule 1112

TPH refers to tons of clinker per hour of cement production.

* Texas has the option of complying with the following technical standard:

Each long wet or long dry kiln for which the following controls are installed and operated during kiln operation is not required to meet the NO_x emission limits of subsection (a) of this section, provided that each owner or operator choosing this option submits written notification of this choice to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction before the appropriate compliance date in §117.524 of this title:

(1) a low-NO_x burner and either:

(A) mid-kiln firing; or

(B) some other form of secondary combustion achieving equivalent levels of NO_x reductions; or alternatively;

(2) other additions or changes to the kiln system achieving at least a 30% reduction in NO_x emissions, provided the additions or changes are approved by the executive director with concurrence from EPA.

(d) Each preheater or precalciner kiln for which either a low-NO_x burner or a low-NO_x precalciner is installed and operated during kiln operation is not required to meet the NO_x emission limits of subsection (a) of this section. Each owner or operator choosing this option shall submit written notification of this choice to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction before the appropriate compliance date in §117.524 of this title.

ERG reviewed US EPA's Summary of State / Local NO_x Regulations for Stationary Sources and selected and reviewed those control measures that apply to cement kilns to create this table. This file is located at : www.epa.gov/ttn/naaqs/ozone/ozonetech/statenoxregs518.pdf

EXHIBIT 22

0

Like 22

Tweet

[Share](#)

Polluting the Poor

TEP's southside coal plant keeps on pumping out noxious gases

by [Tim Vanderpool](#)

The coal pile rises like a black tide, spreading long and deep in the flats along Interstate 10. If Tucson Electric Power has its way, this fuel will eventually feed the Sundt Generating Station, contributing to a haze in our skies and, according to two new reports, more death and illness in the predominantly poor, mostly minority communities that surround it.

"The coal you can see stockpiled from I-10, they want to burn it," says Tucson-based Sierra Club organizer Dan Millis. "We want to keep it on the ground, and out of Tucson's lungs."

Unfortunately, that may not happen anytime soon. Due to the plant's age (the Arizona Department of Environmental Quality concluded that it came online in 1962), Sundt, at 3950 E. Irvington Road, has been exempted from requirements to install costly, emissions-cutting upgrades. The rationale is that those upgrades are unnecessary for plants nearing the end of their productive lives.

The Sierra Club and other groups have questioned that exemption from the state's haze-rule implementation plan, and called upon the U.S. Environmental Protection Agency to review the ADEQ decision.

"The plant should be held to more-stringent standards," says Millis, adding that representatives from environmental groups have met with TEP "to see what we can do to get fewer emissions in our air."

In the meantime, the Sierra Club and other groups want the Sundt generator to switch from coal to natural gas—which it is equipped to do—and save that enormous black pile as an emergency reserve.

Calls to TEP spokesman Joe Salkowski for comment on the Sundt generator were not returned. But two recent reports speak volumes about the toxicity of this plant in Tucson.

One is from the National Association for the Advancement of Colored People, and the other from the Union of Concerned Scientists. Both rank Sundt high on a national list of outdated coal burners that need to be shut down.

According to the Union report, *Ripe for Retirement: The Case for Closing America's Costliest Coal Plants*, 42 percent of our nation's electricity last year was generated by coal-burning plants like Sundt. And like Sundt, more than three-quarters of those plants have outlived their 30-year life spans.

"Most are inefficient," says the report, "operating far below both their power generation potential. ... They lack essential modern pollution controls," it continues, "so they damage public health. The sulfur they emit causes acid rain. The mercury they release poisons waterways and fish and causes neurological damage in children. ... The soot they emit creates smog that causes lung disease, premature death, and triggers asthma attacks. ... Burning coal demands billions of gallons of cooling water from vulnerable rivers and lakes, and leaves behind vast quantities of toxic ash residuals, while coal-mining causes extensive and lasting damage both to human health and the natural environment."

The report goes on to describe coal-fired power plants as "our nation's largest single source of heat-trapping carbon dioxide (CO₂) emissions, the primary contributor to global warming."

And according to the NAACP report, the burden of living with dirty old plants like Sundt disproportionately affects minority neighborhoods. While Rachel Carson's groundbreaking 1962 book *Silent Spring* helped prod America out of its apathy regarding toxic pollutants, that shift did not immediately filter down to working-class minority communities.

There was an awakening in 1982, however, when African-American residents in one rural North Carolina community learned that the toxin polychlorinated biphenyl was being dumped in a nearby landfill. Their outrage resulted in massive civil disobedience and more than 500 arrests. Today's powerful environmental-justice movement is largely attributed to that watershed event.

With the publication of the NAACP's *Coal Blooded: Putting Profits Before People*, that movement is now turning its

[click to enlarge](#)

TIM VANDERPOOL

Dan Millis: "The plant should be held to more-stringent standards."

attention to dirty, aging plants such as Sundt, and highlighting the health toll they exact on surrounding, often-minority communities.

The study looked at 378 coal-fired plants across the country, evaluating their impacts upon minorities and the poor. It also singled out a dozen companies for an "F" rating based on their poor performance in relation to social- and environmental-justice issues.

Among those failing companies was UNS Energy, the parent company of Tucson Electric Power. Like the others, UNS was targeted for having a coal plant "sited ... in densely populated areas with high proportions of low-income people and people of color."

The Sundt plant certainly fits that bill. According to the report, it emits more than 2,000 tons of sulfur dioxide and 1,400 tons of nitrogen oxide each year into the air over some of Tucson's poorest minority neighborhoods. Another study, published by the Clean Air Task Force in 2010, concluded that pollution from Sundt is responsible for six heart attacks, 68 asthma attacks and four deaths each year.

Yet the plant continues burning coal, and polluting neighborhoods that lack the clout to stop it.

"Often, you find there's more political power in communities that *aren't* low income, or communities of color," says Jacqui Patterson, director of the NAACP's Climate Justice Initiative and a co-author of the study.

As a result, polluting plants are "disproportionately in communities of color and low-income communities," Patterson says. "One reason is that property values tend to be lower in areas that have toxic facilities. When someone is low-income, they would look to buy in a place that has lower property costs."

The other factor, she says, "is that political piece, in terms of not having the political power to be able to fight to get something out of the community."

Those communities subsequently suffer from what Patterson calls "clusters" of health concerns. For instance, "across the board, you'll see higher rates of asthma," she says. "African-American children are three times as likely to go into the hospital from asthma, and twice as likely to die from it."

Patterson says tighter federal regulations are in the pipeline. "But meanwhile, these plants have been spewing out toxins for years. How many lives have been lost or compromised without those standards?"

[Currents Feature archives »](#)

Like

Send

22 people like this. [Sign Up](#) to see what your friends like.

4

0

5

Tweet

Facebook Recommendations

Sign Up

Create an account or [log in](#) to see what your friends are recommending.



Certain AZ Legislators Want High Schoolers to Recite a Loyalty Oath Before Graduating

36 people recommended this.



An Amphi High Teacher's Aide Got a Bit Too Friendly With Six(!) Male Students

12 people recommended this.



Pima County, FC Tucson Announce Stadium Deal

25 people recommended this.



James Franco Outdoes Himself With "Obama" Poem

7 people recommended this.

Facebook social plugin